



Westario Power Inc.

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August 22, 2008

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

Dear Ms. Walli,

**Westario Power Inc. – License #ED-2002-0515
2009 Cost of Service Rate Application # EB-2008-0250**

Westario Power Inc. is pleased to submit to the Ontario Energy Board ("OEB") its 2009 Rate Application, in compliance with the OEB Filing Requirements for Transmission and Distribution Applications.

Further to the Board's RESS filing guidelines, an electronic copy of our application will be submitted through the OEB's e-Filing Services. Two hard copies of the application and one electronic version will be supplied to the Board.

We would be please to provide any further information or details that you may require relative to this application.

Respectively submitted,

WESTARIO POWER INC.

Lisa Milne, CGA
Chief Financial Officer
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Westario Power

Westario Power Inc.

2009 EDR Application

EB-2008-0250

Submitted: 22 August, 2008

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Respectively submitted,

WESTARIO POWER INC.

Lisa Milne, CGA
Chief Financial Officer
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Fax: (519) 507-6787
E-mail: lisa.milne@westario.com

Application

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 Westario
Power Inc. ("WPI") 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 commencing May 1, 2009.

APPLICATION

Introduction

The Applicant is Westario Power Inc. (referred to in this Application as the "Applicant" or
"WPI"). The Applicant is a corporation incorporated pursuant to the Ontario Business
Corporations Act with its head office in the Municipality of Walkerton.

The Applicant hereby applies to the Ontario Energy Board (the "OEB") pursuant to section 78
of the Ontario Energy Board Act, 1998 as amended (the "OEB Act") for approval of its
proposed distribution rates and other charges, effective May 1, 2009.

Except where specifically identified in the Application, the Applicant followed Chapter 2 of the
Filing Requirements for Transmission and Distribution Applications dated November 14, 2006
(the "Filing Requirements") in preparing this Application.

Proposed Distribution Rates and Other Charges

The Schedule of Rates and Charges proposed in this Application is identified in Exhibit 1 Tab
1, Schedule 5 of this Summary, and the material being filed in support of this Application sets
out WPI's approach to its 2009 distribution rates and charges.

Proposed Effective Date of Rate Order

The Applicant requests that the OEB make its Rate Order effective May 1, 2009 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:

- I. the proposed rates for the distribution of electricity have been prepared in accordance with the Filing Requirements;
- II. the proposed adjusted rates are necessary to meet the Applicant's Market Based Rate of Return ("MBRR"), Debt Rate and Payments in Lieu of Taxes ("PILs") requirements;
- III. there are no impacts to any of the customer classes or consumption level subgroups that are so significant as to warrant the deferral of any adjustments being requested by the Applicant or the implementation of any other mitigation measures; and
- IV. 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 set out in this Application as just and reasonable rates and charges pursuant to section 78 of the OEB Act, to be effective May 1, 2009, or as soon as possible thereafter. If delays are expected in processing the application and issuing a rate order, WPI is asking for its current rates to be made interim effective May 1, 2009.

DATED at Walkerton, Ontario, this 15 day of August, 2008.



Summary of Application

Introduction

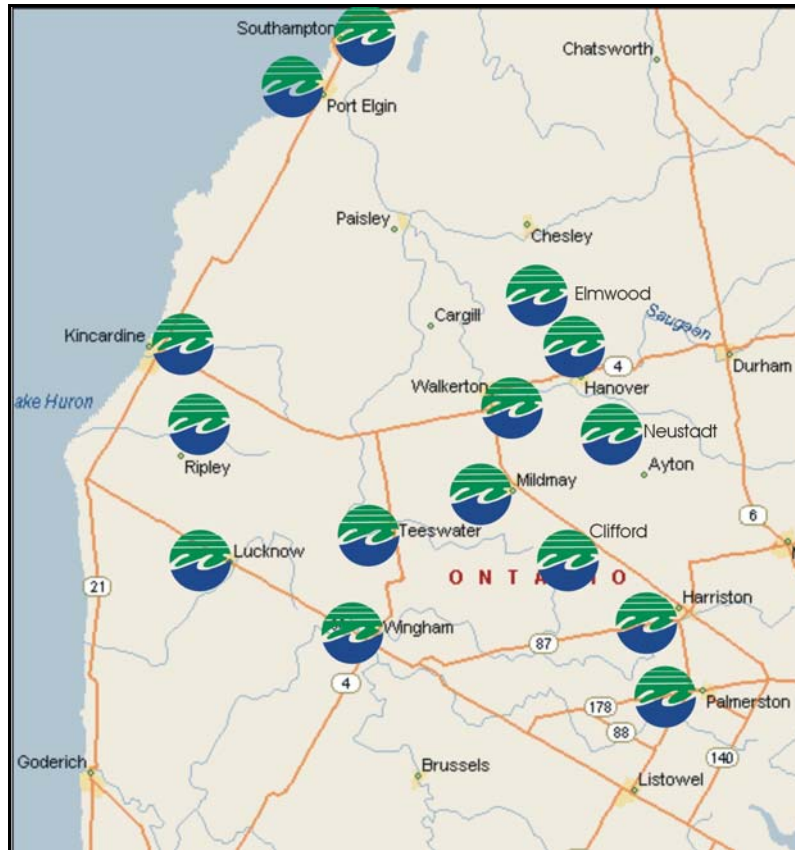
Westario Power Inc. is submitting a cost of service rate application, based on a forward test year, for 2009 Electricity Distribution Rates to be effective from May 1, 2009 to April 30, 2010. This application has been prepared in accordance with the Board's Filing Requirements. The Board's *2006 Electricity Distribution Rate Handbook* ("2006 EDR Handbook") was also used to guide certain elements of the application, such as the grouping of accounts.

Westario Power's Unique Characteristics

On November 1, 2000 Westario Power Holdings Inc. (holding company) and its affiliates Westario Power Services Inc. (services company) and Westario Power Inc. (LDC) were incorporated as new business entities. The shareholders of Westario Power Holdings Inc. included eight municipal shareholders, and one private entity. The service territory of Westario Power Inc. consisted of the territory previously served by the eight (8) municipal entities previously owned by the eight municipal shareholders of Westario Power Holdings Inc. This service territory encompasses fifteen (15) communities.

In 2007, application was made to the Ontario Energy Board (OEB) to amalgamate the holding company, the services company and the LDC into one company, Westario Power Inc. OEB approval was received on July 17, 2007, and the amalgamation took place on January 1, 2008.

The fifteen (15) communities that Westario Power serves are spread over a large geographical area spanning approximately 60 kilometres east/west by 80 kilometres north/south. The area between these service territories is served by Hydro One Networks Inc. A map of the communities that Westario Power services is below.



1
2
3 In addition to being disbursed over a large area, each service territory has a relatively small
4 customer base. In November 2000, there was a total of 17,810 customers. The greatest single
5 customer population is in the towns of Port Elgin/Southampton at 30% of the total. Customer
6 growth is low – averaging approximately 1 percent over all 15 communities.

8 **WPI's Distribution Systems Investment Requirements**

9 Commencing in 2008 WPI began a three-year program to collect data on all installed distribution
10 system assets. This program will permit the development of an effective asset management
11 plan that addresses growth, line loss minimization, reliability performance measures, and
12 financial capabilities of the Company. Westario Power is planning to submit this plan with its
13 next rate application. In the absence of this plan, there are some serious concerns that need to
14 be addressed immediately.

1 As set out in the following sections, as a result of the condition of the state of the existing
2 systems within Westario Power's service area, Westario Power has been increasing its capital
3 investments in order to maintain system safety and reliability. The urgency of this work was
4 apparent to management prior to the initiation of the project to develop a system asset
5 management plan.

6 7 **State of the Inherited Infrastructure**

8 The state of the infrastructure and the types of systems in place vary considerably across the
9 service territories. Some areas were in reasonably good condition prior to the 2000
10 amalgamation, while others were in extremely poor condition.

11
12 In an effort to kept rates down, some predecessor utilities reduced the amount of preventative
13 maintenance undertaken, choosing to focus instead on correcting problems as they arose. The
14 condition of the inherited distribution systems in some communities was poor, while others had
15 made reasonable investments in their systems.

16
17 The lack of investment in capital and maintenance projects is most evident in a variety of areas
18 both small and large. The most serious maintenance issues relate to:

- 19
20 • Tree Trimming – which was minimal and needed to be performed every year;
21 • Substation Maintenance – where regular schedule of maintenance did not exist in most
22 communities;
23 • Pole Replacements – where many poles are beyond their useful life and need replacing,
24 affecting the reliability of the distribution system.
25 • #6 Copper – there was a time when #6 Copper was an inexpensive solution for extending
26 power lines to areas with small energy demand. These areas are now experiencing load
27 growth and feeder extensions off the #6 primary wire. The wire has grown brittle and is
28 undersized for the average load.
29

Investing in the Infrastructure

Investments made by Westario Power in capital and maintenance programs since 2000, have raised the general condition of the distribution systems to the status of fair to good for those projects undertaken. More investment is needed and this application details the continued efforts proposed in these areas.

For the ongoing maintenance and upkeep, a number of programs have been put in place including:

- Tree Trimming – where trimming in all communities is carried out on a rotating three year schedule and trees are trimmed sufficiently to provide the required clearances for the timeframe;
- Substation Maintenance – where plans are in place for a three year schedule, the work performed is documented and any identified issues are addressed;
- Pole Replacements – where capital pole replacement budgets are allocated on an annual basis. Poles are prioritized for replacement based upon age, condition and potential adverse impact on the reliability of the distribution system; and
- #6 Copper Conductor – where continuing and expanding on the capital projects carried out over recent years, the 2009 Capital Works identified in this application proposes a more aggressive plan to replace #6 copper.

These programs are ongoing and will continue for the foreseeable future. Additionally, other past and proposed capital projects have been undertaken to address line losses by removing undersized and over-utilized assets from service and replacing them with larger capacity and more robust plant. These initiatives are retiring undersized feeder and conductors and deploying more accurate meters into the distribution system.

Westario Power has limited growth of approximately 250 customers per year or 1% of its total customer base. In past years, WPI has invested 1 ½ to 2 times the amount of amortization into its distribution plant. The majority of WPI's capital spending has been due to the necessity of upgrading WPI's current distribution system, rather than as a result of customer growth. Due to

1 the minimal growth of WPI's customer base, there have been little additional revenues to fund
2 the level of capital expenditures that have been required for the public safety and reliability of
3 the distribution system.

4 5 **Systems and Asset Management**

6 Each former utility had its own customer billing system and financial systems, making
7 centralization a major challenge. Some former LDCs even managed through manual systems.
8 Documentation on the distribution system assets was generally limited to maps of the system.
9 There were no records containing such information as age of equipment, years in service,
10 fuse/disconnect ratings, equipment manufacturer, PCB surveys, condition assessments, failure
11 history, transformer connections, etc. In addition to the operating challenges that this lack of
12 information presents, it has prevented the development of a cost effect asset management plan
13 that addresses growth, line loss minimization, reliability performance measures, and financial
14 capabilities of the Company.

15
16 Through the merger, the Company has installed one computer information system with fully
17 integrated customer billing/inquiry, financial, project management, purchasing, device
18 management and inventory modules. Customer inquiries are now addressed through a central
19 call centre with the capabilities of tracking the customer service related Service Quality Indicator
20 (SQI) targets. WPI is addressing the lack of information on its infrastructure through the three-
21 year data collection program mentioned above.

22 23 **Scope of Application**

24 This application seeks approval for a 2009 service revenue requirement based on a forecast for
25 2009 of Operations, Maintenance and Administration ("OM&A") expenses, return on rate base,
26 amortization expense and payments in lieu of taxes ("PILs"). For the determination of the
27 revenue requirement for distribution rates, the revenue from other sources, referred to as other
28 revenue, is subtracted from the service revenue requirement and the credit provided to
29 customers for transformer ownership is added back.

1 For OM&A, capital expenditures and other revenue, WPI has grouped the accounts in the
2 manner described in Appendix A of the 2006 EDR Handbook. The rate base is determined from
3 an average of opening and closing net book values ("NBV") of assets for the 2009 Test Year,
4 plus a working capital allowance. The return on rate base is determined using the Board
5 deemed capital structure as determined in the *Report of the Board on Cost of Capital and*
6 *Incentive Regulation* dated December 20, 2006 ("Board Report on CoC and IRM"). The rate of
7 return on equity ("ROE") and short-term interest rates have also been determined in accordance
8 with the Board Report on CoC and IRM.

9
10 PILs have been determined using the same methodology as in the 2006 EDR Handbook. Large
11 Corporation Tax has now been eliminated and is therefore no longer included in the calculation.

12
13 WPI's revenue requirement for 2009 contemplates the recovery of its costs of providing
14 distribution service; its permitted Return on Equity and the funds necessary to service its debt
15 (based on the OEB's deemed debt/equity ratio which is subject to adjustment this year to move
16 towards the OEB-mandated 60% debt/40% equity); and its Payments in Lieu of Taxes ("PILs").
17 When its forecasted results for 2009 are taken into account, WPI estimates that its current rates
18 will produce a deficiency in distribution revenue of \$1,462,691 for the 2009 Test Year. Excluded
19 from this estimate is the impact of energy costs. The Applicant therefore seeks the Board's
20 approval to revise its rates applicable to its distribution of electricity. The issues to be reviewed
21 in this case, as the applicant sees them, are discussed below.

22
23 As illustrated in Table 1 on the next page, the proposed rates will recover WPI's forecasted
24 revenue requirement of \$9,265,283. WPI's proposed distribution rates are necessary to avoid a
25 forecasted revenue deficiency in the amount of \$1,462,691 during the 2009 rate year.

Table 1 – Summary of Revenue Requirement

		Reference
Cost of Capital		
Rate Base	\$33,630,199	Exhibit 2, Tab 1
Requested Rate of Return	6.96%	Exhibit 6, Tab 1
Cost of Service	\$2,339,543	Exhibit 4 Tab 1
Operations, Maintenance and Administration	4,868,425	Exhibit 4, Tab 2
Amortization	1,829,713	Exhibit 4, Tab 2
PILS	897,156	Exhibit 4, Tab 3
Service Revenue Requirement	9,934,837	Exhibit 4 Tab 3
Other Revenue	(669,555)	Exhibit 3 Tab 3
Base Revenue Requirement	\$9,265,283	Exhibit 3 Tab 3

The major components of Table 1 are described below:

Rate Base

Table 2 – Rate Base

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Projection	2009 Projection
Opening Balance	20,118,370	21,121,135	22,383,568	25,725,285	27,491,909
Ending Balance	19,508,372	22,383,568	25,725,285	27,491,909	28,242,596
Average Balance	19,813,371	21,752,352	24,054,427	26,608,597	27,867,253
Working Capital Allowance	5,284,227	5,308,729	5,451,977	5,689,824	5,762,946
Total Rate Base	25,097,598	27,061,081	29,506,403	32,298,421	33,630,199

WPI's forecasted revenue deficiency can be primarily attributed to its proposed rate base additions. The last full rebasing of WPI's distribution rates took place in the 2004 year. Capital expenditures since that time are not reflected in WPI's rate base, although capital expenditures have increased since 2004 and the need for more capital improvements will continue over the next three years. These improvements are necessary due to the condition of the system as described above.

Continued investment in the distribution infrastructure results in a forecast growth in the year-end NBV of assets between the 2006 EDR Approved and the 2009 test year of \$8,734,224. This includes investments related to the Asset Management Plan, capacity planning, general plant purchases and the construction of a new building that houses Westario's workforce and head office. Details of these capital expenditures can be found in Exhibit 2.

Also, on January 1, 2008, Westario Power Inc., Westario Power Holdings Inc. and Westario Power Services Inc. amalgamated to form a single corporation that carries on as a distribution company under the name Westario Power Inc. The shareholders of Westario Power Holdings Inc. remain the shareholders of the amalgamated company. The amalgamation process increased the utility's non-distribution related assets by a net book value amount of \$1,057,820. Details of these capital additions can be found in Exhibit 2.

Operating Costs

WPI's operating costs include operations, maintenance, & administration ('OM&A'). A summary of WPI's operating costs are set out in the following table:

Table 3 – Operating Costs

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Projection	2009 @ existing rates
OM&A Expenses	4,864,634	4,321,872	4,653,188	4,909,115	4,868,425

WPI's OM&A is fairly stable and has increased by less than \$4,000 in the 2009 Test year from the 2006 EDR Approved year. This is due to WPI's ongoing commitment to finding efficiencies while ensuring the safe and reliable operation of our distribution plant. More information on WPI's operating costs are shown in Exhibit 4.

Other Items Affecting Rates

Through this Application, WPI seeks to recover a Revenue Deficiency in the amount of \$1,462,691 arising from changes in Gross Assets, Amortization, Rate of Return, and PILS. The Applicant also seeks to recover certain Balances of Deferral and Variance Account and collect the amount of \$1,134,993. Through this application, WPI also seeks to update its Total Distribution Loss Factor bringing it from 1.0637 to 1.0788.

The Board's Decision on the 2006 EDR Application approved an annual amount of \$257,598 for low voltage ("LV") charges. These are amounts that WPI pays to Hydro One Networks Inc. for shared distribution lines and stations. For the period from May 2006 to June 2008, however, WPI paid approximately \$1,500,000 to Hydro One Networks Inc. and recorded the variance in Account 1150 – LV Variance Account. Upon a review of the 2006 EDR application, WPI has

1 determined that amount for LV charges was considerably understated. Therefore, WPI is
2 seeking approval to increase the low voltage charges to customers to \$733,477. Details are
3 provided in Exhibit 3, Tab 5, Schedule 1.
4

5 **Timing**

6 The financial information supporting the Test Year for this Application will be the Applicant's
7 fiscal year ending December 31, 2009 (the "2009 Test Year"). However, this information will be
8 used to set rates for the period May 1, 2009 to April 30, 2010. The Test Year revenue
9 requirement is that forecast by the Applicant as needed to enable it to recover the amounts
10 discussed above for fiscal 2009.
11

12 **Other Items**

13 WPI has been assisted in preparing this rate application by Elenchus Research Associates who
14 provided the model used in the determination of just and reasonable 2009 Distribution Rates.
15 The Applicant has based this Application on its forecasted results for the 2009 Test Year. As
16 required by the OEB, the Applicant is also presenting the historical actual information for fiscal
17 Board Approved, 2006 Actual and 2007 Actual; as well as six months actual and six months
18 forecast information for the fiscal 2008 bridge year.

1 **Current Rates Schedule**

2

3 The following attachment is the Current Rates Schedule.

4

Westario Power Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0865

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.

MONTHLY RATES AND CHARGES

Residential

Service Charge	\$	10.87
Distribution Volumetric Rate	\$/kWh	0.0133
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0044
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0054
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

General Service Less Than 50 kW

Service Charge	\$	19.72
Distribution Volumetric Rate	\$/kWh	0.0086
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0048
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

General Service 50 to 4,999 kW

Service Charge	\$	240.15
Distribution Volumetric Rate	\$/kW	2.2158
Retail Transmission Rate – Network Service Rate	\$/kW	1.6425
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.9371
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

General Service 50 to 4,999 kW – Time of Use

Service Charge	\$	43.94
Distribution Volumetric Rate	\$/kW	0.3324
Retail Transmission Rate – Network Service Rate	\$/kW	1.7431
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	2.1233
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Unmetered Scattered Load

Service Charge (per customer)	\$	4.40
Distribution Volumetric Rate	\$/kWh	0.0453
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0048
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Westario Power Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0865

Sentinel Lighting

Service Charge (per connection)	\$	1.35
Distribution Volumetric Rate	\$/kW	6.9632
Retail Transmission Rate – Network Service Rate	\$/kW	1.2450
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.5286
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Street Lighting

Service Charge (per connection)	\$	2.31
Distribution Volumetric Rate	\$/kW	1.9554
Retail Transmission Rate – Network Service Rate	\$/kW	1.2388
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.4973
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	\$	15.00
Statement of Account	\$	15.00
Pulling post dated cheques	\$	15.00
Duplicate invoices for previous billing	\$	15.00
Request for other billing information	\$	15.00
Easement letter	\$	15.00
Income tax letter	\$	15.00
Notification charge	\$	15.00
Account history	\$	15.00
Credit reference/credit check (plus credit agency costs)	\$	15.00
Returned cheque charge (plus bank charges)	\$	15.00
Charge to certify cheques	\$	15.00
Legal letter charge	\$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	\$	30.00
Special meter reads	\$	30.00
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 disconnect	\$	30.00
Collection of account charge – no disconnect – after regular hours	\$	165.00
Disconnect/Reconnect Charges at meter – during regular hours	\$	65.00
Disconnect/Reconnect Charges at meter – after regular hours	\$	185.00
Disconnect/Reconnect at pole – during regular hours	\$	185.00
Disconnect/Reconnect at pole – after regular hours	\$	415.00
Install/Remove load control device – during regular hours	\$	65.00
Install/Remove load control device – after regular hours	\$	185.00
Service call – customer owned equipment	\$	30.00
Service call – after regular hours	\$	165.00
Temporary service installation and removal – overhead – no transformer	\$	500.00
Temporary service installation and removal – underground – no transformer	\$	300.00
Temporary service installation and removal – overhead – with transformer	\$	1,000.00
Specific charge for access to power poles \$/pole/year	\$	22.35

Westario Power Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2008

**This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors**

EB-2007-0865

Allowances

Transformer Allowance for Ownership - per kW of billing demand/month	\$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Retail Service Charges (if applicable)

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	\$	100.00
Monthly Fixed Charge, per retailer	\$	20.00
Monthly Variable Charge, per customer, per retailer	\$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	\$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	\$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	\$	0.25
Processing fee, per request, applied to the requesting party	\$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	\$	2.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0637
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0530
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Proposed Rates Schedule

The following attachment is the Proposed Rates Schedule.

Appendix 1-1

**Effective
May 1/09**

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Page 1 of 3

Residential

Service Charge	\$	13.84
Distribution Volumetric Rate	\$/kWh	0.0161
Regulatory Asset Recovery	\$/kWh	0.0015
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0044
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0054
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

General Service Less Than 50 kW

Service Charge	\$	25.05
Distribution Volumetric Rate	\$/kWh	0.0106
Regulatory Asset Recovery	\$/kWh	0.0012
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0048
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

General Service 50 to 4,999 kW

Service Charge	\$	240.89
Distribution Volumetric Rate	\$/kW	3.2034
Regulatory Asset Recovery	\$/kW	0.4079
Retail Transmission Rate – Network Service Rate	\$/kW	1.6425
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.9371
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Unmetered Scattered Load

Service Charge	\$	11.19
Distribution Volumetric Rate	\$/kWh	0.0475
Regulatory Asset Recovery	\$/kWh	0.0019
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0048
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Sentinel Lighting

Service Charge (per connection)	\$	4.92
Distribution Volumetric Rate	\$/kW	20.2204
Regulatory Asset Recovery	\$/kW	0.8041
Retail Transmission Rate – Network Service Rate	\$/kW	1.2450
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.5286
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Appendix 1-1

**Effective
May 1/09**

Street Lighting

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Service Charge (per connection)	\$	4.28
Distribution Volumetric Rate	\$/kW	3.6270
Regulatory Asset Recovery	\$/kW	0.7275
Retail Transmission Rate – Network Service Rate	\$/kW	1.2388
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.4973
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Appendix 1-1

		Effective May 1/09
Specific Service Charges		
Arrears Certificate	\$	15.00
Statement of Account	\$	15.00
Pulling post-dated cheques	\$	15.00
Duplicate invoices for previous billing	\$	15.00
Request for other billing information	\$	15.00
Easement Letter	\$	15.00
Income tax letter	\$	15.00
Notification Charge	\$	15.00
Account history	\$	15.00
Credit reference/credit check (plus credit agency costs)	\$	15.00
Returned Cheque charge (plus bank charges)	\$	15.00
Charge to certify cheque	\$	15.00
Legal letter charge	\$	15.00
Account set up charge / change of occupancy charge	\$	30.00
Special Meter reads	\$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	\$	30.00
Late Payment - per month	%	1.50
Collection of account charge – no disconnection	\$	30.00
Collection of account charge – no disconnection – after regular hours	\$	165.00
Disconnect/Reconnect at meter – during regular hours	\$	65.00
Disconnect/Reconnect at meter – after regular hours	\$	185.00
Disconnect/Reconnect at pole – during regular hours	\$	185.00
Disconnect/Reconnect at pole – after regular hours	\$	415.00
Install / remove load control device – during regular hours	\$	65.00
Install / remove load control device – after regular hours	\$	185.00
Service call – customer-owned equipment	\$	30.00
Service call – after regular hours	\$	165.00
Temporary service install and remove – overhead – no transformer	\$	500.00
Temporary service install and remove – underground – no transformer	\$	300.00
Temporary service install and remove – overhead – with transformer	\$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	\$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	\$/kW	-0.60
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	-1.00
LOSS FACTORS		
Secondary Metered Customer < 5,000 kW		1.0788
Primary Metered Customer < 5,000 kW		1.0680

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Page 3 of 3

Summary of Bill Impact

Residential

RPP: Summer

1,000 kWh's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge				\$10.87			\$13.84	\$2.97	27.3%
Distribution	kWh	1,000	\$0.0133	\$13.30	1,000	\$0.0161	\$16.10	\$2.80	21.1%
Sub-Total (Distribution)				\$24.17			\$29.94	\$5.77	23.9%
Deferral/Variance Dispositions	kWh	1,000			1,000	\$0.0015	\$1.50	\$1.50	
Electricity (Commodity)	kWh	1,064	RPP-Summer	\$57.36	1,079	RPP-Summer	\$58.25	\$0.89	1.6%
Transmission - Network	kWh	1,064	\$0.0044	\$4.68	1,079	\$0.0044	\$4.75	\$0.07	1.5%
Transmission - Connection	kWh	1,064	\$0.0054	\$5.74	1,079	\$0.0054	\$5.83	\$0.09	1.6%
Wholesale Market Service	kWh	1,064	\$0.0052	\$5.53	1,079	\$0.0052	\$5.61	\$0.08	1.4%
Rural Rate Protection	kWh	1,064	\$0.0010	\$1.06	1,079	\$0.0010	\$1.08	\$0.02	1.9%
Debt Retirement Charge	kWh	1,000	\$0.0007	\$0.70	1,000	\$0.0007	\$0.70		
TOTAL BILL				\$99.24			\$107.66	\$8.42	8.5%

In order to increase the fixed cost recovery, WPI is proposing to increase the monthly customer charge by \$2.97 in the 2009 Test Year.

The impact on a Residential customer consuming 1,000 kWhs in the summer is an increase of 23.9% on the delivery component of the bill; and an overall bill impact of 8.5%. The overall bill impact on a Residential customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

1

Residential

RPP: Winter

1,000 kWh's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge				\$10.87			\$13.84	\$2.97	27.3%
Distribution	kWh	1,000	\$0.0133	\$13.30	1,000	\$0.0161	\$16.10	\$2.80	21.1%
Sub-Total (Distribution)				\$24.17			\$29.94	\$5.77	23.9%
Deferral/Variance Dispositions	kWh	1,000			1,000	\$0.0015	\$1.50	\$1.50	
Electricity (Commodity)	kWh	1,064	RPP-Winter	\$53.76	1,079	RPP-Winter	\$54.65	\$0.89	1.7%
Transmission - Network	kWh	1,064	\$0.0044	\$4.68	1,079	\$0.0044	\$4.75	\$0.07	1.5%
Transmission - Connection	kWh	1,064	\$0.0054	\$5.74	1,079	\$0.0054	\$5.83	\$0.09	1.6%
Wholesale Market Service	kWh	1,064	\$0.0052	\$5.53	1,079	\$0.0052	\$5.61	\$0.08	1.4%
Rural Rate Protection	kWh	1,064	\$0.0010	\$1.06	1,079	\$0.0010	\$1.08	\$0.02	1.9%
Debt Retirement Charge	kWh	1,000	\$0.0007	\$0.70	1,000	\$0.0007	\$0.70		
TOTAL BILL				\$95.64			\$104.06	\$8.42	8.8%

2

3 In order to increase the fixed cost recovery, WPI is proposing to increase the monthly customer charge by \$2.97 in the 2009
 4 Test Year.

5

6 The impact on a Residential customer consuming 1,000 kWhs in the winter is an increase of 23.9% on the delivery component
 7 of the bill; and an overall bill impact of 8.8%. The overall bill impact on a Residential customer is shown in detail in Exhibit 9,
 8 Tab 1, Schedule 9.

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General Service Less Than 50 kW

RPP: Non-res.

2,000 kWh's	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge				\$19.72			\$25.05	\$5.33	27.0%
Distribution	kWh	2,000	\$0.0086	\$17.20	2,000	\$0.0106	\$21.20	\$4.00	23.3%
Sub-Total (Distribution)				\$36.92			\$46.25	\$9.33	25.3%
Deferral/Variance Dispositions	kWh	2,000			2,000	\$0.0012	\$2.40	\$2.40	
Electricity (Commodity)	kWh	2,127	RPP-Non-res.	\$118.77	2,158	RPP-Non-res.	\$120.55	\$1.78	1.5%
Transmission - Network	kWh	2,127	\$0.0040	\$8.51	2,158	\$0.0040	\$8.63	\$0.12	1.4%
Transmission - Connection	kWh	2,127	\$0.0048	\$10.21	2,158	\$0.0048	\$10.36	\$0.15	1.5%
Wholesale Market Service	kWh	2,127	\$0.0052	\$11.06	2,158	\$0.0052	\$11.22	\$0.16	1.4%
Rural Rate Protection	kWh	2,127	\$0.0010	\$2.13	2,158	\$0.0010	\$2.16	\$0.03	1.4%
Debt Retirement Charge	kWh	2,000	\$0.0007	\$1.40	2,000	\$0.0007	\$1.40		
TOTAL BILL				\$189.00			\$202.97	\$13.97	7.4%

2

3

4 In order to increase the fixed cost recovery, WPI is proposing to increase the monthly customer charge by \$5.33 in the 2009
 5 Test Year.

6

7 The impact on a General Service less than 50 kW customer consuming 2,000 kWhs is an increase of 25.3% on the delivery
 8 component of the bill; and an overall bill impact of 7.4%. The overall bill impact on a General Service less than 50 kW
 9 customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

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General Service 50 to 4,999 kW

RPP: Non-res.

22,000 kWh's 50 kW's	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge				\$240.15			\$240.89	\$0.74	0.3%
Distribution	kW	50	\$2.2158	\$110.79	50	\$3.2034	\$160.17	\$49.38	44.6%
Sub-Total (Distribution)				\$350.94			\$401.06	\$50.12	14.3%
Deferral/Variance Dispositions	kW	50			50	\$0.4079	\$20.40	\$20.40	
Electricity (Commodity)	kWh	23,401	RPP-Non-res.	\$1,373.93	23,734	RPP-Non-res.	\$1,393.53	\$19.60	1.4%
Transmission - Network	kW	50	\$1.6425	\$82.13	50	\$1.6425	\$82.13		
Transmission - Connection	kW	50	\$1.9371	\$96.86	50	\$1.9371	\$96.86		
Wholesale Market Service	kWh	23,401	\$0.0052	\$121.69	23,734	\$0.0052	\$123.41	\$1.72	1.4%
Rural Rate Protection	kWh	23,401	\$0.0010	\$23.40	23,734	\$0.0010	\$23.73	\$0.33	1.4%
Debt Retirement Charge	kWh	22,000	\$0.0007	\$15.40	22,000	\$0.0007	\$15.40		
TOTAL BILL				\$2,064.35			\$2,156.52	\$92.17	4.5%

2

3 In order to increase the fixed cost recovery, WPI is proposing to increase the monthly customer charge by \$0.74 in the 2009
 4 Test Year.

5

6 The impact on a General Service 50 – 4,999 kW customer consuming 22,000 kWhs and 50 kW is an increase of 14.3% on the
 7 delivery component of the bill; and an overall bill impact of 4.5%. The overall bill impact on a General Service 50 – 4,999 kW
 8 customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

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Unmetered Scattered Load

RPP: Non-res.

350 kWh's	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge				\$4.40			\$11.19	\$6.79	>100%
Distribution	kWh	350	\$0.0453	\$15.86	350	\$0.0475	\$16.63	\$0.77	4.9%
Sub-Total (Distribution)				\$20.26			\$27.82	\$7.56	37.3%
Deferral/Variance Dispositions	kWh	350			350	\$0.0019	\$0.67	\$0.67	
Electricity (Commodity)	kWh	372	RPP-Non-res.	\$18.61	378	RPP-Non-res.	\$18.88	\$0.27	1.5%
Transmission - Network	kWh	372	\$0.0040	\$1.49	378	\$0.0040	\$1.51	\$0.02	1.3%
Transmission - Connection	kWh	372	\$0.0048	\$1.79	378	\$0.0048	\$1.81	\$0.02	1.1%
Wholesale Market Service	kWh	372	\$0.0052	\$1.94	378	\$0.0052	\$1.96	\$0.02	1.0%
Rural Rate Protection	kWh	372	\$0.0010	\$0.37	378	\$0.0010	\$0.38	\$0.01	2.7%
Debt Retirement Charge	kWh	350	\$0.0007	\$0.25	350	\$0.0007	\$0.25		
TOTAL BILL				\$44.71			\$53.28	\$8.57	19.2%

2

3 In order to increase the fixed cost recovery, WPI is proposing to increase the monthly customer charge by \$6.79 in the 2009
 4 Test Year.

5

6 The impact on a Unmetered Scattered Load customer consuming 350 kWhs is an increase of 37.3% on the delivery
 7 component of the bill; and an overall bill impact of 19.2%. The overall bill impact on an Unmetered Scattered Load customer
 8 is shown in detail in Exhibit 9, Tab 1, Schedule 9.

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Sentinel Lighting

RPP: Non-res.

2,000 kWh's 10 kW's	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				\$1.35			\$4.92	\$3.57	>100%
Distribution	kW	10	\$6.9632	\$69.63	10	\$20.2204	\$202.20	\$132.57	>100%
Sub-Total (Distribution)				\$70.98			\$207.12	\$136.14	>100%
Deferral/Variance Dispositions	kW	10			10	\$0.8041	\$8.04	\$8.04	
Electricity (Commodity)	kWh	2,127	RPP-Non-res.	\$118.77	2,158	RPP-Non-res.	\$120.55	\$1.78	1.5%
Transmission - Network	kW	10	\$1.2450	\$12.45	10	\$1.2450	\$12.45		
Transmission - Connection	kW	10	\$1.5286	\$15.29	10	\$1.5286	\$15.29		
Wholesale Market Service	kWh	2,127	\$0.0052	\$11.06	2,158	\$0.0052	\$11.22	\$0.16	1.4%
Rural Rate Protection	kWh	2,127	\$0.0010	\$2.13	2,158	\$0.0010	\$2.16	\$0.03	1.4%
Debt Retirement Charge	kWh	2,000	\$0.0007	\$1.40	2,000	\$0.0007	\$1.40		
TOTAL BILL				\$232.08			\$378.23	\$146.15	63.0%

2

3 In order to increase the fixed cost recovery, WPI is proposing to increase the monthly customer charge by \$3.57 in the 2009
 4 Test Year.

5

6 The impact on a Sentinel Lighting customer consuming 2,000 kWhs and 10 kW's is an increase greater than 100% on the
 7 delivery component of the bill; and an overall bill impact of 63.0%. The overall bill impact on a Sentinel Lighting customer is
 8 shown in detail in Exhibit 9, Tab 1, Schedule 9.

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1

Street Lighting

RPP: Non-res.

500 kWh's 3 kW's	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				\$2.31			\$4.28	\$1.97	85.3%
Distribution	kW	3	\$1.9554	\$5.87	3	\$3.6270	\$10.88	\$5.01	85.5%
Sub-Total (Distribution)				\$8.18			\$15.16	\$6.98	85.4%
Deferral/Variance Dispositions	kW	3			3	\$0.7275	\$2.18	\$2.18	
Electricity (Commodity)	kWh	532	RPP-Non-res.	\$26.59	539	RPP-Non-res.	\$26.97	\$0.38	1.4%
Transmission - Network	kW	3	\$1.2388	\$3.72	3	\$1.2388	\$3.72		
Transmission - Connection	kW	3	\$1.4973	\$4.49	3	\$1.4973	\$4.49		
Wholesale Market Service	kWh	532	\$0.0052	\$2.77	539	\$0.0052	\$2.80	\$0.03	1.1%
Rural Rate Protection	kWh	532	\$0.0010	\$0.53	539	\$0.0010	\$0.54	\$0.01	1.9%
Debt Retirement Charge	kWh	500	\$0.0007	\$0.35	500	\$0.0007	\$0.35		
TOTAL BILL				\$46.63			\$56.21	\$9.58	20.6%

2

3

4 In order to increase the fixed cost recovery, WPI is proposing to increase the monthly customer charge by \$1.97 in the 2009
 5 Test Year.

6

7 The impact on a Street Lighting customer consuming 500 kWhs and 3 kW's is an increase of 85.4% on the delivery component
 8 of the bill; and an overall bill impact of 20.6%. The overall bill impact on a Street Lighting customer is shown in detail in Exhibit
 9 9, Tab 1, Schedule 9.

10

List of Issues

There are a number of generic issues that, although they may not all be defined as major, are anticipated to be examined in this case. These issues are listed below.

List of Generic Issues

Capital Structure

The Applicant's current deemed capital structure is 50% debt and 50% equity. In its December 20, 2006 Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors, the OEB mandated a shift to a 60% debt/40% equity ratio for all distributors. Consequently, WPI is requesting a change in its deemed capital structure. Specifically, WPI is requesting a move in the deemed equity ratio from 46.67% to 43.33% consistent with the 3 year phase-in of WPI's capital structure from 50% to 40% equity.

Return on Equity

In addition, WPI has assumed a return on equity of 8.57% consistent with the methodology outlined in Appendix B of the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated December 20, 2006. WPI understands the OEB will be finalizing the return on equity for 2009 rates based on January 2009 market interest rate information.

Capital Expenditures

WPI continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory.

Operating and Maintenance Costs

Operating and maintenance costs have been updated to reflect the impact of inflation and expected changes in costs.

List of Specific Approvals Requested

WPI requests the following specific approvals:

1. Approval to charge rates effective May 1, 2009 to recover a forecasted revenue requirement \$9,265,283 net of Other Revenue offsets adjusted for Low Voltage wheeling charges of \$733,477 from Hydro One Networks Inc. and Transformer Allowance Costs of \$69,720.
2. Approval to discharge and/or dispose of the principle of certain deferral variance accounts to December 31, 2007 and the projected accrued interest to April 30, 2009.
3. Approval of our Specific Services charges listed in Exhibit 1, Tab 1, Schedule 5.
4. Approval of WPI's proposed change in capital structure involving the shift in deemed common equity component from 46.67% to 43.33% (Exhibit 6), consistent with the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors dated December 20, 2006.
5. Approval of the proposed total loss factor of 1.0788 as determined in Exhibit 4, Tab 2, Schedule 9.
6. WPI has not included any costs related to Smart Metering. In decision EB-2007-0865 dated April 17, 2008, the Board approved \$0.26 per month per metered customer. Westario is requesting an increase of this smart meter seed amount from \$0.26 to \$1.00/month per metered customer, consistent with the Decisions issued for the 2008 Cost of Service Applicants.
7. Approval of Hydro One Networks Inc. pass-through Transmission/Connection/ Network Charges.
8. Approval of all IESO Market pass-through charges including Debt Retirement.

9. Approval to continue the following deferral/variance accounts on May 1, 2009

- o 1505 Un-recovered Plant and Regulatory Study Costs
- o 1508 Other Regulatory Assets
- o 1510 Preliminary Survey and Investigation Charges
- o 1515 Emission Allowance Inventory
- o 1516 Emission Allowances Withheld
- o 1518 Retail Cost Variance Account – Retail
- o 1520 Power Purchase Variance Account
- o 1525 Miscellaneous Deferred Debits – including Rebate Cheques
- o 1530 Deferred Losses from Disposition of Utility Plant
- o 1540 Unamortized Loss on Re-acquired Debt
- o 1545 Development Charge Deposits/Receivables
- o 1548 Retail Cost Variance Account – STR
- o 1550 LV Variance Account
- o 1555 Smart Meter Capital Variance Account
- o 1556 Smart Meters OM&A Variance Account
- o 1560 Deferred Development Cost
- o 1562 Deferred Payments in Lieu of Taxes
- o 1563 PILS Contra Account
- o 1565 CMD Expenditure and Recoveries
- o 1566 CDM Contra Account
- o 1570 Qualifying Transition Costs
- o 1571 Pre-Market Opening Energy Variances Total
- o 1572 Extra-Ordinary Event Losses
- o 1574 Deferred Rate Impact Amounts
- o 1580 RSVA-Wholesale Market Service Charge
- o 1582 RSVA-One-time Wholesale Market Service
- o 1584 RSVA-Retail Transmission Network Charge
- o 1586 RSVA-Retail Transmission Connection Charge
- o 1588 RSVA-Power
- o 1592 Deferred PILs Account
- o 2425 Other Deferred Credits

Schedule of Overall Revenue Deficiency/Sufficiency

The following attachment is the Schedule of Overall Revenue Deficiency/Sufficiency.

Appendix 7-1

Revenue Sufficiency / Deficiency

	2009 Projection	2008 Projection	Var #	Var %
Utility Income (see below)	1,317,573	1,037,544	280,029	27.0%
Utility Rate Base	33,630,199	32,298,421	1,331,779	4.1%
Indicated Rate of Return	3.92%	3.21%	0.71%	22.0%
Requested / Approved Rate of Return	6.96%	6.96%		
Sufficiency / (Deficiency) in Return	(3.04%)	(3.74%)	0.71%	18.8%
Net Revenue Sufficiency / (Deficiency)	(1,021,971)	(1,209,352)	187,382	15.5%
Provision for PILs/Taxes	(440,720)	(1,195,912)	755,192	63.1%
Gross Revenue Sufficiency / (Deficiency)	(1,462,691)	(2,405,264)	942,574	39.2%
Deemed Overall Debt Rate	5.72%	5.11%	0.61%	12.0%
Deemed Cost of Debt	1,090,630	825,225	265,405	32.2%
Utility Income less Deemed Cost of Debt	226,943	212,319	14,624	6.9%
Return On Deemed Equity	1.56%	1.52%	0.04%	2.7%
UTILITY INCOME				
Total Net Revenues	8,472,147	8,468,376	3,771	0.0%
OM&A Expenses	4,811,825	4,858,515	(46,690)	(1.0%)
Depreciation & Amortization	1,829,713	1,720,456	109,257	6.4%
Taxes other than PILs / Income Taxes	56,600	50,600	6,000	11.9%
Total Costs & Expenses	6,698,138	6,629,571	68,567	1.0%
Utility Income before Income Taxes / PILs	1,774,009	1,838,805	(64,796)	(3.5%)
PILs / Income Taxes	456,436	801,261	(344,825)	(43.0%)
Utility Income	1,317,573	1,037,544	280,029	27.0%

Causes of the Deficiency/Sufficiency

The forecasted revenue deficiency of \$1,462,691 is mainly attributable to the substantial increase in capital investment and the resulting rate of return on capital as described in Exhibit 6, Tab 1, Schedule 3. The projected rate base of \$33,630,199 is an increase of \$8,532,601 from the 2006 EDR Approved rate base. Of this amount, \$8,053,882 is directly attributable to the net capital additions by WPI. WPI remains committed to providing a safe and reliable distribution system for its customers, the public and its employees, and has such as invested substantial capital into its distribution plant as outlined in Exhibit 2.

Total net revenues have been projected to decrease by approximately \$44,000 from 2008 to 2009 due to projected decreases in interest revenue and revenues from jobbing. There is a slight increase projected in the 2009 OM&A expenses from 2006 EDR approved, in the amount of approximately \$4,000.

Board Findings and Directions from 2008 EDR

The following attachment is the Board Findings and Directions from 2008 EDR.



EB-2007-0865

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 Westario
Power Inc. for an order or orders approving or fixing just
and reasonable distribution rates and other charges, to
be effective May 1, 2008.

BEFORE: Paul Vlahos
Presiding Member

Paul Sommerville
Member

DECISION

Introduction

Westario Power Inc. is a licensed distributor of electricity providing service to consumers within its licensed service area. Westario Power Inc. 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, 2008.

Westario Power Inc. is one of over 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, Westario Power Inc. is one of the electricity distributors to have its rates adjusted for 2008 on the basis of the 2nd Generation Incentive Rate Mechanism (“IRM”) process.

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 2008 rate adjustments ("the Guidelines") for distributors applying for rate adjustments pursuant to the IRM process.

Notice of Westario Power Inc.'s rate application was given through newspaper publication in Westario Power Inc.'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. Board staff participated actively in the proceeding.

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

Westario Power Inc.'s rate application was filed on the basis of the Guidelines. In fixing new rates and charges for Westario Power Inc., 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 2007 data published by Statistics Canada, the Board has established the price escalator to be 2.1%. The resulting price cap index adjustment is therefore 1.1%. 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. In addition, a change in the federal income tax rate effective January 1, 2008 was also incorporated into the rate model and reflected in distribution rates.

The Board also considered the reduction in Ontario capital tax and the increase in capital cost allowance (CCA) applicable to certain buildings and computers acquired after March 2007. The Board has decided that adjustments related to these items are

not required, either because the changes are not of general application, or because they do not appear to be material.

The price cap index adjustment does not apply to the following components of the rates:

- the specific service charges;
- the smart meter rate adder (an amount in the fixed components of the rates associated with smart meter cost recovery); and
- any continuing rate riders.

Accordingly, the Board is providing Westario Power Inc. with a rate model (spreadsheet) that reflects the price cap adjustments described above. Westario Power Inc. is required to review the rate model (spreadsheet) and to confirm its completeness and accuracy with the Board at the time it files its Draft Rate Order. Westario Power Inc. shall file with the Board a Draft Rate Order attaching the proposed Tariff of Rates and Charges which will reflect the Board's price cap adjustments as verified by Westario Power Inc. and any other Board findings contained in this decision that would impact 2008 rates. Westario Power Inc. shall also provide the rate model (spreadsheet) that underpins the Tariff of Rates and Charges. Any changes to the Board's rate model (spreadsheet) shall be clearly identified and explained.

Rate Riders

When the Board approved new rates for distributors for 2006, it also approved the recovery of regulatory asset balances on a final basis. The Board approved rate riders to facilitate the recovery of the approved balances over the two remaining years of the four-year recovery period mandated by the Minister of Energy (i.e. May 1, 2004 to April 30, 2008). The rate rider(s) associated with the recovery of regulatory assets will cease on May 1, 2008 and shall be removed from the Tariff of Rates and Charges, unless a previous Board decision authorized the continuation of such riders beyond April 30, 2008. No such authorization has been previously provided by the Board for Westario Power Inc. The final balance in account 1590 cannot be confirmed until after the current recovery period has expired, i.e. after April 30, 2008. Once the residual balance in deferral account 1590 is finalized, the residual balance will be disposed in a future proceeding.

Smart Meter Rate Adder

Westario Power Inc. requested the continuation of the smart meter rate adder previously approved by the Board in order to provide funding for possible future implementation of smart meter costs and to minimize future rate impacts. The Board-approved rate adder for Westario Power Inc. of \$0.26 per month per metered customer shall continue. Westario Power Inc.'s variance accounts for smart meter program implementation costs, previously authorized by the Board, shall also be continued.

Retail Transmission Service Rates

On October 17, 2007, the Board issued its EB-2007-0759 Rate Order setting new Uniform Transmission Rates for Ontario transmitters, effective November 1, 2007. The Board approved a decrease of 18% to the wholesale transmission network rate, a decrease of 28% to the wholesale transmission line connection rate, and an increase of 7% to the wholesale transformation connection rate. The combined change in the wholesale transmission line connection and transformation connection rates is a reduction to the connection rate of 5%.

On October 29, 2007, the Board issued a letter to all electricity distributors directing them to propose an adjustment to their retail transmission service (RTS) rates to reflect the new Uniform Transmission Rates for Ontario transmitters effective November 1, 2007. The objective of resetting the rates was to minimize the prospective balance in variance accounts 1584 and 1586 and also to mitigate intergenerational inequities. Westario Power Inc. did not file a proposal to adjust its RTS rates. Given the magnitude of the changes in wholesale transmission rates, the Board directs Westario Power Inc. to reduce its RTS – Network Service Rates by 18% and its RTS – Line and Transformation connection Service Rates by 5%. Westario Power Inc. is required to include this change in its rate model (spreadsheet) to be filed with the Board.

Implementation

Westario Power Inc.'s new distribution rates are effective May 1, 2008. The Board directs that:

1. Westario Power Inc. shall file with the Board a Draft Rate Order attaching the proposed Tariff of Rates and Charges and the supporting rate model (spreadsheet) within seven (7) days of the date of this Decision. The proposed Tariff of Rates and Charges shall be filed in a Word format. The adjusted rate model shall be filed in an Excel format.

DATED at Toronto, March 13, 2008.

Original Signed By

Paul Vlahos
Presiding Member

Original Signed By

Paul Sommerville
Member

Board Findings and Directions from 2007 EDR

The following attachment is the Board Findings and Directions from 2007 EDR.



EB-2007-0591

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 Westario
Power Inc. for an order or orders approving or fixing just
and reasonable distribution rates and other charges, to
be effective May 1, 2007.

BEFORE: Paul Sommerville
Presiding Member

Paul Vlahos
Member

Ken Quesnelle
Member

DECISION AND ORDER

Westario Power Inc. ("Westario Power") is a licensed distributor providing electrical service to consumers within its licensed service area. Westario 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, 2007.

Westario Power is one of 85 electricity distributors in Ontario that are regulated by the Board. To streamline the process for the approval of distribution rates and charges for these 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. The Report contained the relevant guidelines for 2007 rate adjustments ("the guidelines") for distributors applying for rates only on the basis of the cost of capital and 2nd generation incentive regulation mechanism policies set out in the Report.

Public notice of Westario Power's rate application was given through newspaper publication in Westario Power's service area. The evidence filed as part of the rate application was made available to the public. Both Westario Power and interested parties had the opportunity to file written submissions in relation to the rate application. The Board received and considered a letter of comment from Mr. Lorne Shantz. 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.

Westario Power's rate application was filed on the basis of the guidelines. In fixing new rates and charges for Westario Power, the Board has applied the policies described in the Report.

After confirming the accuracy of the 2006 rate tariff and accompanying materials submitted in the rate application, the Board applied its approved price cap index adjustment to distribution rates (fixed and variable) uniformly across all customer classes. The price cap index is calculated as a price escalator less an X-factor of 1.0%, intended to represent input price and productivity trends. Based on the final 2006 data published by Statistics Canada, the Board has established the price escalator to be 1.9%. The resulting price cap index adjustment is therefore 0.9%.

The price cap index adjustment was not applied to the following components of the rates:

- the specific service charges;
- the regulatory asset recovery rate rider; and
- the smart meter rate adder (an amount in the fixed components of the rates associated with smart meter cost recovery).

Westario Power requested an amount for smart meter costs. The Board has approved an amount of \$0.26 per month per metered customer. Westario Power's variance accounts for smart meter program implementation costs, previously authorized by the Board, are continued. It is the Board's understanding that Westario Power will not be undertaking any smart metering activity (i.e. discretionary metering activity) in 2007. The amount collected through the smart meter rate adder will be booked into the existing variance accounts, and retained in those accounts, to help fund future smart meter activity. As the notice of this application indicated, the Board will be holding a combined proceeding to consider, among other things, appropriate recovery of smart meter costs.

The Board has made the necessary adjustments to Westario Power's filed 2006 Tariff of Rates and Charges to produce a new Tariff of Rates and Charges to be effective May 1, 2007. The Board finds the rates and charges in the Tariff of Rates and Charges attached as Appendix A to this decision to be just and reasonable.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix A of this order is approved, effective May 1, 2007, for electricity consumed or estimated to have been consumed on and after May 1, 2007.
2. The Tariff of Rates and Charges set out in Appendix A of this order supersedes all previous distribution rate schedules approved by the Ontario Energy Board for Westario Power, and is final in all respects.
3. Westario Power shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, April 12, 2007.

ONTARIO ENERGY BOARD

Original signed by

Peter H. O'Dell
Assistant Board Secretary

Appendix A

EB-2007-0591

April 12, 2007

ONTARIO ENERGY BOARD

Westario Power Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0591

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, 2007 for all consumption or deemed consumption services used on or after that date.

SPECIFIC SERVICE CHARGES – May 1, 2007 for all charges incurred by customers on or after that date.

LOSS FACTOR ADJUSTMENT – May 1, 2007 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 refers to customers residing in residential dwelling units taking energy at 600 volts or less, with energy generally supplied as single phase, 3-wire, 60 Hertz, having a nominal voltage of 120/240 volts.

General Service Less than 50 kW

This classification refers to general service buildings, defined as buildings that are used for purposes other than single-family dwellings, taking energy at 600 volts or less, requiring a connection with a connected load of less than 50 kW, and including Town Houses and Condominiums that require centralized bulk metering, 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 refers to general service buildings, defined as buildings that are used for purposes other than single-family dwellings, requiring a connection with a connected load greater than 50 kW but less than 5,000 kW, 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.

General Service 50 to 4,999 kW – Time of Use

This classification refers to general service buildings, defined as buildings that are used for purposes other than single-family dwellings, requiring a connection with a connected load greater than 50 kW but less than 5,000 kW on time of use rates, 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.

Unmetered Scattered Load

This classification refers to an account taking electricity at 600 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, 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.

Westario Power Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0591

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.

MONTHLY RATES AND CHARGES

Residential

Service Charge	\$	10.92
Distribution Volumetric Rate	\$/kWh	0.0134
Regulatory Asset Recovery	\$/kWh	0.0066
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0057
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

General Service Less Than 50 kW

Service Charge	\$	19.82
Distribution Volumetric Rate	\$/kWh	0.0086
Regulatory Asset Recovery	\$/kWh	0.0035
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0051
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

General Service 50 to 4,999 kW

Service Charge	\$	241.36
Distribution Volumetric Rate	\$/kW	2.2269
Regulatory Asset Recovery	\$/kW	0.5778
Retail Transmission Rate – Network Service Rate	\$/kW	2.0031
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	2.0391
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

General Service 50 to 4,999 kW – Time of Use

Service Charge	\$	44.16
Distribution Volumetric Rate	\$/kW	0.3341
Regulatory Asset Recovery	\$/kW	0.1466
Retail Transmission Rate – Network Service Rate	\$/kW	2.1257
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	2.2350
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Westario Power Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2007

**This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors**

EB-2007-0591

Unmetered Scattered Load

Service Charge (per customer)	\$	4.42
Distribution Volumetric Rate	\$/kWh	0.0455
Regulatory Asset Recovery	\$/kWh	0.0071
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0051
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Sentinel Lighting

Service Charge (per connection)	\$	1.36
Distribution Volumetric Rate	\$/kW	6.9982
Regulatory Asset Recovery	\$/kW	9.4597
Retail Transmission Rate – Network Service Rate	\$/kW	1.5183
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.6091
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Street Lighting

Service Charge (per connection)	\$	2.32
Distribution Volumetric Rate	\$/kW	1.9652
Regulatory Asset Recovery	\$/kW	0.0424
Retail Transmission Rate – Network Service Rate	\$/kW	1.5107
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.5761
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	\$	15.00
Statement of Account	\$	15.00
Pulling post dated cheques	\$	15.00
Duplicate invoices for previous billing	\$	15.00
Request for other billing information	\$	15.00
Easement letter	\$	15.00
Income tax letter	\$	15.00
Notification charge	\$	15.00
Account history	\$	15.00
Credit reference/credit check (plus credit agency costs)	\$	15.00
Returned cheque charge (plus bank charges)	\$	15.00
Charge to certify cheques	\$	15.00
Legal letter charge	\$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	\$	30.00
Special meter reads	\$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	\$	30.00

Westario Power Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2007

**This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors**

EB-2007-0591

Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnect	\$	30.00
Collection of account charge – no disconnect – after regular hours	\$	165.00
Disconnect/Reconnect Charges at meter – during regular hours	\$	65.00
Disconnect/Reconnect Charges at meter – after regular hours	\$	185.00
Disconnect/Reconnect at pole – during regular hours	\$	185.00
Disconnect/Reconnect at pole – after regular hours	\$	415.00
Install/Remove load control device – during regular hours	\$	65.00
Install/Remove load control device – after regular hours	\$	185.00
Service call – customer owned equipment	\$	30.00
Service call – after regular hours	\$	165.00
Temporary service installation and removal – overhead – no transformer	\$	500.00
Temporary service installation and removal – underground – no transformer	\$	300.00
Temporary service installation and removal – overhead – with transformer	\$	1,000.00
Specific charge for access to power poles \$/pole/year	\$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	\$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0637
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0530
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Board Findings and Directions from 2006 EDR

The following attachment is the Board Findings and Directions from the 2006 EDR.



RP-2005-0020
EB-2006-0041

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 Westario Power Inc. for an order or orders pursuant to section 78 of the *Ontario Energy Board Act, 1998* for 2006 distribution rates and related matters;

AND IN THE MATTER OF an application by Westario Power Inc. for an order or orders pursuant to section 78 of the *Ontario Energy Board Act, 1998* pertaining to the Final Recovery of Regulatory Assets - Phase 2.

BEFORE: Paul Vlahos
Presiding Member

Cynthia Chaplin
Member

DECISION WITH REASONS

BACKGROUND

In January 2006, Westario Power Inc. (“Westario Power” or the “Applicant”) submitted an application for final recovery of its regulatory asset balances, pursuant to Chapter 10 of the Board’s December 9, 2004 *Review and Recovery of Regulatory Assets - Phase 2 Decision with Reasons* and the July 12, 2005 regulatory asset filing guidelines. Westario Power filed its application under the comprehensive review option, and the application was filed as part of the main 2006 distribution rates application. The regulatory assets claim totalled \$7,091,750, of which \$2,012,212 plus carrying charges represented the total transition cost claim. The intervenors of record were the Vulnerable Energy Consumers Coalition (“VECC”), Energy Probe Research Foundation (“Energy Probe”) and the School Energy Coalition (“SEC”).

Pursuant to Procedural Order #2, parties conducted a settlement conference on April 20, 2006. Westario Power met with the intervenors of record, with the exception of SEC who did not participate. Board Staff were also in attendance but were not party to the settlement proposal. A complete agreement was reached and a settlement proposal was filed with the Board on May 8, 2006. The settlement agreement proposed a reduction in Westario Power's transition cost claim of \$271, 212, resulting in a revised claim of \$1,750,000 plus carrying charges. All other non-transition cost accounts were accepted as filed. The total revised regulatory assets claim is \$6,754,995 including carrying charges. The settlement indicated that SEC was sent a copy of the proposal and that SEC had not taken a position on it.

The Board has reviewed the application, responses to interrogatories, and the settlement proposal. The Board is satisfied that the record is complete and will therefore dispense with an oral hearing.

BOARD FINDINGS

The Board accepts the application as amended by the settlement agreement. The Board finds that the cost of service consequences resulting from the agreement are acceptable. The Board notes that the consequences of its findings in this Decision will be incorporated into the rate order for Westario Power that will result from the Decision on Westario Power's main 2006 distribution rates application.

The Board awards VECC, Energy Probe and SEC 100 percent of their reasonably incurred costs with respect to this comprehensive regulatory assets proceeding. However, the Board does not anticipate that SEC will file a cost claim for a significant amount. The implementation of this decision on cost awards will be incorporated into the overall process for awarding intervenor costs for the 2006 electricity distribution rates review.

DATED AT Toronto, June 15, 2006

Original signed by

Paul Vlahos
Presiding Member

Original signed by

Cynthia Chaplin
Member



RP-2005-0020
EB-2005-0434

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 Westario
Power Inc. for an order or orders approving or fixing just
and reasonable distribution rates and other charges,
effective May 1, 2006.

BEFORE: Paul Vlahos
Presiding Member

DECISION AND ORDER

Westario Power Inc. ("WPI" or the "Applicant") is a licensed distributor providing electrical service to consumers within its defined service area. WPI filed an application (the "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 matters, to be effective May 1, 2006. According to the Board's schedule for filings, WPI was to have filed its application no later than September 6, 2005. WPI actually filed in January 2006.

WPI is one of over 90 electricity distributors in Ontario that are regulated by the Board. To streamline the process for the approval of distribution rates and charges for these distributors, the Board developed and issued the *2006 Electricity Distribution Rate Handbook* (the "Handbook") and complementary spreadsheet-based models. These materials were developed after extensive public consultation with distributors, customer groups, public and environmental interest groups, and other interested parties. The Handbook contains requirements and guidelines for filing an application. The models determine the amounts to be included for the payments in lieu of taxes ("PILs") and calculate rates based on historical financial and other information entered by the distributor.

Also included in this process was a methodology and model for the final recovery of regulatory assets flowing from the Board's decision dated December 9, 2004 on the Review and Recovery of Regulatory Assets – Phase 2 for Toronto Hydro, London Hydro, Enersource Hydro Mississauga and Hydro One. In Chapter 10 of the decision, the Board outlined a Phase 2 process for the remaining distributors. By letter of July 12, 2005, the Board provided guidance and a spreadsheet-based model to the distributors for the inclusion of this recovery as part of their 2006 distribution rate applications.

As a distributor that is embedded in Hydro One Network's low voltage system, the Applicant has included the recovery of certain Regulatory Assets that have been allocated by Hydro One Networks. The amount claimed by the Applicant was provided by Hydro One Networks as a reasonable approximation of the actual amount that Hydro One Networks will assess the Applicant. To the degree that the amount differs from the actual amount approved for Hydro One Networks in another proceeding (RP-2005-0020/EB-2005-0378), this difference will be reconciled at the end of the Regulatory Asset recovery period, as set out in the Phase II regulatory assets decision issued on December 9, 2004 (RP-2004-0064/RP-2004-0069/RP-2004-0100/RP-2004-0117/RP-2004-0118).

In its preliminary review of the 2006 rate applications received from the distributors, the Board identified several issues that appeared to be common to many or all of the distributors. As a result, the Board held a hearing (EB-2005-0529) to consider these issues (the "Generic Issues Proceeding") and released its decision (the "Generic Decision") on March 21, 2006. The rulings flowing from that Generic Decision apply to this Application, except to the extent noted in this Decision. The Board notes that pursuant to ss. 21 (6.1) of the *Ontario Energy Board Act, 1998*, and to the extent that it is pertinent to this Application, the evidentiary record of the Generic Issues Proceeding is part of the evidentiary record upon which the Board is basing this Decision.

In December 2001, the Board authorized the establishment of deferral accounts by the distributors related to the payments that the distributors make to the Ministry of Finance in lieu of taxes. The Board is required, under its enabling legislation, to make an order with respect to non-commodity deferral accounts once every twelve months. The Board has considered the information available with respect to these accounts and orders that the amounts recorded in the accounts will not be reflected in rates as part of the Rate Order that will result from this Decision. The Board will continue to monitor the accounts with a view to clearing them when appropriate.

Public notice of the rate Application made by WPI was given through newspaper publication in its service area. The evidence filed was made available to the public. Interested parties intervened in the proceeding. The evidence in the Application was tested through written interrogatories from Board staff and intervenors, and intervenors and WPI had the opportunity to file written argument. While the Board has considered the entire record in this proceeding, it has made reference in this Decision only to such evidence and argument as is necessary to provide context to its findings.

On April 28, 2006, the Board issued an Order declaring rates then existing for WPI to be interim, effective May 1, 2006, until such time as the Board issued a final rate order for 2006 rates. This Decision and Order is final with respect to 2006 rates and supersedes the Order of April 28.

WPI has requested an amount of \$10,667,828 as revenue to be recovered through distribution rates and charges. Included in this amount is a debit of \$1,828,502 for the recovery of regulatory assets. Except where noted in this Decision, the Board finds that WPI has filed its Application in accordance with the Handbook and the guidelines for the recovery of regulatory assets.

Notwithstanding WPI's general compliance with the Handbook and associated models, in considering this Application the Board reviewed the following matters in detail:

- Low Voltage Rates;
- Bad Debt; and
- Consequences of the Generic Decision (EB-2005-0529).

Low Voltage Rates

WPI included in its Application recovery of ongoing Low Voltage ("LV") charges that Hydro One Networks will be levying on WPI for Low Voltage wheeling distribution services provided to WPI.

The Board notes that this estimate reflects Hydro One Networks' current approved LV rate of \$0.56/kW. The Board further notes that Hydro One Networks has applied for an LV rate of \$0.63/kW in its 2006 rate application RP-2005-0020/EB-2005-0378, and the Board has approved this rate.

The Board is of the view that the LV adjustment that WPI has included in its Application is insufficient to recover its expected LV charges in 2006, as this amount does not reflect the updated Hydro One Networks rate. Although the Generic Decision provides that embedded distributors are to track differences between LV costs charged by the host distributor(s) and corresponding revenues recovered from ratepayers, the Board seeks to minimize systemic sources of variance. The Board is of the view that WPI's rates should reflect the LV rates authorized by the Board for the host distributor. Accordingly, the Board has revised the amount for LV charge recovery in WPI's revenue requirement.

Bad Debt

The Applicant is proposing a bad debt expense of \$175,000 for rate making purposes, which is an adjustment to lower the expense from \$309,503 in 2004. The Board notes that, in response to a Staff Interrogatory, WPI noted that it has undertaken extensive measures to improve its bad debt expense and that its 2005 experience significantly reverses the upward trend over the previous three years. The Board commends WPI for these steps and accepts the proposal.

Consequences of the Generic Decision on this Application

The Generic Decision contains findings relevant to funding for smart meters for electricity distributors. The Applicant did file a specific smart meter plan in the revenue requirement. In this situation, the Generic Decision provides that an amount determined as \$3.50 per meter per month installed during the rate year be reflected in the Applicant's revenue requirement, instead of the smart meter-related costs proposed by the Applicant. Consequently, the amounts that the Applicant has proposed in the 2006 rate Application have been removed and replaced with the amount determined in accordance with the Generic Decision. Furthermore, the Board finds in this Decision that this smart meter revenue will be allocated to all metered customers and recovered through the monthly service charge. The revised amount is reflected in the approved monthly service charges contained in the Tariff of Rates and Charges appended to this Decision. Pursuant to the Generic Decision, a variance account will be established, the details of which will be communicated in due course.

Resulting Revenue Requirements

As a result of the Board's determinations on these issues, the Board has adjusted the revenue requirement to be recovered through distribution rates and charges to \$10,647,151 including a debit amount of \$1,828,502 for the recovery of Regulatory Assets.

In its letter of December 20, 2004 to electricity distributors, the Board indicated that it would consider the disposition of the 2005 OEB dues recorded in Account 1508 in this proceeding. However, given that the final 2005 OEB dues are not available because of the difference in fiscal years for the Board and the distributors, and given that the model used to develop the Application does not incorporate this provision, the Board will review and dispose of the 2005 OEB dues at a later time.

Cost Awards

This Application is one of a number of applications before the Board dealing with 2006 rates chargeable by distributors. Intervenors may be parties to multiple applications and, if eligible, their costs associated with a specific distributor may not be separable. Therefore, for these applications, the matter of intervenor cost awards will be addressed by the Board at a later date, upon the conclusion of the current rate applications. If an intervenor that is eligible to recover its costs is able to uniquely identify its costs associated with this Application, it must file its cost claim within 10 days from the receipt of this Decision.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix "A" of this Order is approved, effective June 15, 2006, for electricity consumed or estimated to have been consumed on and after June 15, 2006. The application of the revised distribution rates shall be prorated to June 15, 2006. If Westario Power Inc.'s billing system is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors shall be implemented upon the first subsequent billing for each billing cycle.
2. The Tariff of Rates and Charges set out in Appendix "A" of this Order supersedes all previous distribution rate schedules approved by the Ontario Energy Board for Westario Power Inc., and is final in all respects.

3. Westario Power Inc. shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, June 15, 2006.

ONTARIO ENERGY BOARD

A handwritten signature in black ink, appearing to read "P. O'Dell", written over a horizontal line.

Peter H. O'Dell
Assistant Board Secretary

Appendix "A"

RP-2005-0020
EB-2005-0434

June 15, 2006

ONTARIO ENERGY BOARD

Westario Power Inc.

TARIFF OF RATES AND CHARGES

Effective June 15, 2006

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RP-2005-0020
EB-2005-0434

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 – June 15, 2006 for all consumption or deemed consumption services used on or after that date.

SPECIFIC SERVICE CHARGES - June 15, 2006 for all charges incurred by customers on or after that date.

LOSS FACTOR ADJUSTMENT – June 15, 2006 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 refers to customers residing in residential dwelling units taking energy at 600 volts or less, with energy generally supplied as single phase, 3-wire, 60 Hertz, having a nominal voltage of 120/240 volts.

General Service Less than 50 kW

This classification refers to general service buildings, defined as buildings that are used for purposes other than single-family dwellings, taking energy at 600 volts or less, requiring a connection with a connected load of less than 50 kW, and including Town Houses and Condominiums that require centralized bulk metering, 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 refers to general service buildings, defined as buildings that are used for purposes other than single-family dwellings, requiring a connection with a connected load greater than 50 kW but less than 5,000 kW, 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.

General Service 50 to 4,999 kW – Time of Use

This classification refers to general service buildings, defined as buildings that are used for purposes other than single-family dwellings, requiring a connection with a connected load greater than 50 kW but less than 5,000 kW on time of use rates, 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.

Unmetered Scattered Load

This classification refers to an account taking electricity at 600 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, 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.

Westario Power Inc.

TARIFF OF RATES AND CHARGES

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RP-2005-0020

EB-2005-0434

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.

MONTHLY RATES AND CHARGES

Residential

Service Charge	\$	11.02
Distribution Volumetric Rate	\$/kWh	0.0133
Regulatory Asset Recovery	\$/kWh	0.0066
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0057
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge	\$	0.25

General Service Less Than 50 kW

Service Charge	\$	19.85
Distribution Volumetric Rate	\$/kWh	0.0085
Regulatory Asset Recovery	\$/kWh	0.0035
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0051
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge	\$	0.25

General Service 50 to 4,999 kW

Service Charge	\$	239.41
Distribution Volumetric Rate	\$/kW	2.2070
Regulatory Asset Recovery	\$/kW	0.5778
Retail Transmission Rate – Network Service Rate	\$/kW	2.0031
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	2.0391
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	\$	0.25

General Service 50 to 4,999 kW – Time of Use

Service Charge	\$	43.97
Distribution Volumetric Rate	\$/kW	0.3311
Regulatory Asset Recovery	\$/kW	0.1466
Retail Transmission Rate – Network Service Rate	\$/kW	2.1257
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	2.2350
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	\$	0.25

Originally Issued June 15, 2006

Revised June 28, 2006

Westario Power Inc.

TARIFF OF RATES AND CHARGES

Effective June 15, 2006

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RP-2005-0020
EB-2005-0434

Unmetered Scattered Load

Service Charge (per customer)	\$	4.38
Distribution Volumetric Rate	\$/kWh	0.0451
Regulatory Asset Recovery	\$/kWh	0.0071
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0051
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	\$	0.25

Sentinel Lighting

Service Charge (per connection)	\$	1.35
Distribution Volumetric Rate	\$/kW	6.9358
Regulatory Asset Recovery	\$/kW	9.4597
Retail Transmission Rate – Network Service Rate	\$/kW	1.5183
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.6091
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	\$	0.25

Street Lighting

Service Charge (per connection)	\$	2.30
Distribution Volumetric Rate	\$/kW	1.9477
Regulatory Asset Recovery	\$/kW	0.0424
Retail Transmission Rate – Network Service Rate	\$/kW	1.5107
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.5761
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	\$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	\$	15.00
Statement of Account	\$	15.00
Pulling post dated cheques	\$	15.00
Duplicate invoices for previous billing	\$	15.00
Request for other billing information	\$	15.00
Easement letter	\$	15.00
Income tax letter	\$	15.00
Notification charge	\$	15.00
Account history	\$	15.00
Credit reference/credit check (plus credit agency costs)	\$	15.00
Returned cheque charge (plus bank charges)	\$	15.00
Charge to certify cheques	\$	15.00
Legal letter charge	\$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	\$	30.00
Special meter reads	\$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	\$	30.00

Originally Issued June 15, 2006
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RP-2005-0020
EB-2005-0434

Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnect	\$	30.00
Collection of account charge – no disconnect – after hours	\$	165.00
Disconnect/Reconnect Charges - At Meter During Regular Hours	\$	65.00
Disconnect/Reconnect Charges - At Meter after Regular Hours	\$	185.00
Disconnect/Reconnect at pole – during regular hours	\$	185.00
Disconnect/Reconnect at pole – after regular hours	\$	415.00
Install/Remove load control device – during regular hours	\$	65.00
Install/Remove load control device – after regular hours	\$	185.00
Service call – customer owned equipment	\$	30.00
Service call – after regular hours	\$	165.00
Temporary service installation and removal – overhead – no transformer	\$	500.00
Temporary service installation and removal – underground – no transformer	\$	300.00
Temporary service installation and removal – overhead – with transformer	\$	1,000.00
Specific charge for access to power poles \$/pole/year	\$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	\$	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0637
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0530
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Status of Board Directives

There were no specific directives that emanated from 2006, 2007 or 2008 Board findings and directions.

Utility Description

Name of distributor: Westario Power Inc.

License number: ED-2002-0515

Communities served: Westario Power serves 15 communities in Bruce, Grey and Wellington counties: Clifford, Elmwood, Hanover, Harriston, Kincardine, Lucknow, Mildmay, Neustadt, Palmerston, Port Elgin, Ripley, Southampton, Teeswater, Walkerton and Wingham.

Adjacent distributors: Hydro One Networks Inc.

Characteristics: Large non-contiguous service area (80 x 60 km) consisting of 15 urban communities in 3 counties with Hydro One Networks Inc. serving the interurban areas.

Embedded/Host: Westario Power is embedded in Hydro One Networks Inc.'s low voltage distribution system.

Mailing address: 24 EastRidge Road R.R #2
Walkerton, ON N0G 2V0

Key contacts: Lisa Milne, Chief Financial Officer

Telephone: 519-507-6666, ext. 216

Fax: 519-507-6787

Email: lisa.milne@westario.com

Westario Power Backgrounder

Pre-Westario Power Background

Westario Power Formation

On November 1, 2000 Westario Power Holdings Inc. and its' affiliates Westario Power Services Inc. and Westario Power Inc. were incorporated as new business entities. The shareholders of Westario Power Holdings Inc were:

The Township of Huron-Kinloss	3.19%
The Municipality of Kincardine	13.48%
The Municipality of South Bruce	3.67%
The Town of Saugeen Shores	24.98%
The Township of North Huron	7.71%
The Municipality of Brockton	12.61%
The Town of Hanover	15.09%
The Town of Minto	9.28%
Fortis Ontario Inc.	9.99%

The corporation was comprised of the following corporate entities:

Westario Power Holdings Inc.	Holding Company
Westario Power Inc.	Local Distribution Company
Westario Power Services Inc.	Services Company

In 2007, Westario Power Holdings Inc. applied to the Ontario Energy Board (OEB) to amalgamate Westario Power Inc. and Westario Power Services Inc. into Westario Power Holdings Inc. and then rename the resulting company as Westario Power Inc. This would consolidate the three companies as a Local Distribution Company (LDC) only.

OEB approval was received on July 17, 2007, and the amalgamation took place on January 1, 2008.

Predecessor Utilities

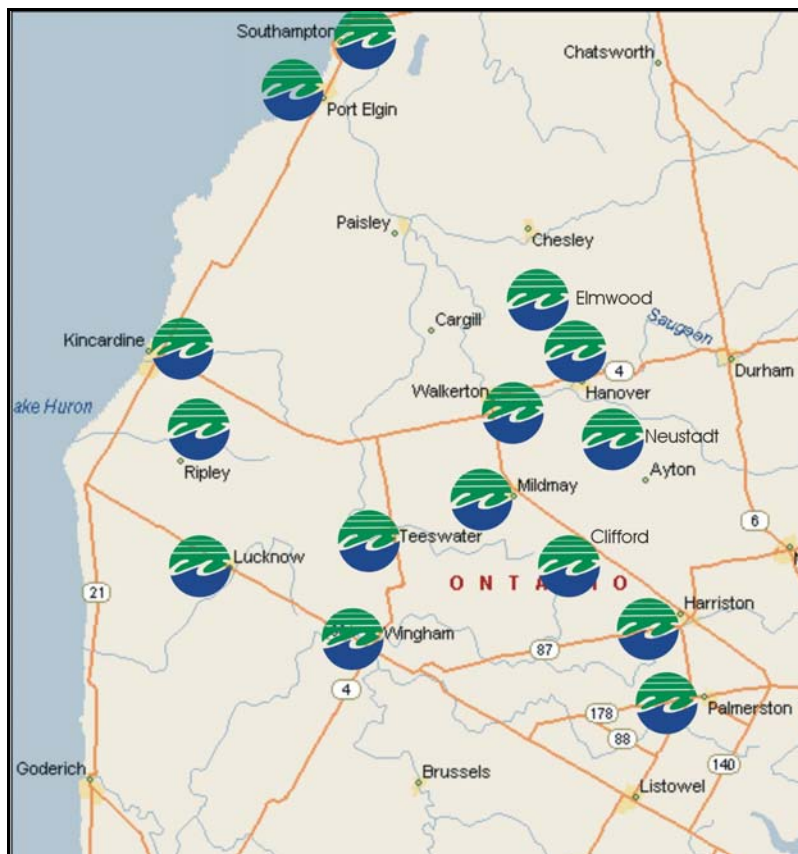
The service territories currently supplied by Westario Power were previously served by eight (8) municipal entities. Table 1 below lists the service territories supplied by the predecessor utilities and the number of customers they served.

Table 1
Predecessor Utility Service Territories

Municipal Entity	Predecessor Utility Service Area	November 2000 Customer Count
The Township of Huron-Kinloss	Village of Ripley Village of Lucknow	1,200
The Municipality of Kincardine	Kincardine (Ward 1)	3,089
The Municipality of South Bruce	Village of Mildmay Village of Teeswater	1,094
The Town of Saugeen Shores	Town of Port Elgin Town of Southampton	5,293
The Township of North Huron	Town of Wingham	1,484
The Municipality of Brockton	Town of Walkerton Village of Elmwood	2,367
The Town of Hanover	Town of Hanover Village of Neustadt	3,283
The Town of Minto	Village of Clifford Town of Harriston Town of Palmerston	2,360

Nature of Our Distribution Systems

As shown in the following map, the fifteen (15) communities that comprise Westario Power's service territory are spread over a large geographical area spanning approximately 60 kilometres east/west by 80 kilometres north/south. The area between these service territories is served by Hydro One Networks Inc.



In addition to being disbursed over a large area, each service territory has a relatively small customer base. Customer growth is low – averaging about 1 percent over all communities.

An overview of the distribution system in each community is provided below:

Port Elgin

Port Elgin also has one of the highest rates of residential and commercial growth within Westario Power's service territory.

1
2 The Port Elgin distribution system is approximately 60 percent underground. The overhead
3 portion is in reasonable condition. However, much of the overhead system is comprised of
4 aerial spaced conductor that will require reconstructing to achieve minimum clearances between
5 the high voltage conductors as required under the Electrical Safety Code.

6
7 There is a significant amount of 5 kV underground distribution comprised of butyl rubber cable.
8 This type of cable has shown to have a life expectancy of about 20 years. Most of this cable is
9 well over 30 years old. When it fails, the major problem is that it is direct buried. The cost for
10 emergency boring is extremely high when dealing with a lateral feed. In a number of cases, it
11 has been necessary to set poles temporarily and string lines to re-supply customers. A 10-year
12 program to replace all butyl rubber cables was initiated in 2006. This program will be placed on
13 hold in 2009 to allow Westario Power address the more heavily weighted projects involving No.
14 6 copper wire and pole-line replacements.

15
16 Four projects to replace No. 6 copper conductors have been identified and these replacements
17 will be undertaken in future budget years.

18
19 Five pole-line replacement projects have been identified for Port Elgin. One pole-line
20 replacement will be undertaken in 2009.

21 22 **Southampton**

23 Like Port Elgin, Southampton also has one of the highest rates of residential growth within
24 Westario Power's service territory.

25
26 Southampton is primarily an overhead system (approximately 75 percent). Thirty-five areas that
27 have No. 6 copper conductors have been identified. Three projects will be undertaken in 2009.
28 The balance of these projects will be undertaken in future budget years.

29
30 Six pole line replacement projects have been identified in Southampton; one of which will be
31 undertaken in 2008, and the balance will be undertaken in future budget years.

Kincardine

The Kincardine system is 75 percent overhead and in fair to good condition. Kincardine has a high rate of residential growth.

In 2008 the final phase of the 5 kV underground cable replacement program will be undertaken in Kincardine. The 2008 work will eliminate the remainder of all PoleTrans transformers and the removal of the balance of the 5 KV cable. No further budgeting will be required in Kincardine to replace the old 5kv cable.

In 2008 a small underground cable and foundation replacement program is required on Hunter Street for public safety, as the old fibreglass foundations are collapsing.

Kincardine has a large amount of No. 6 copper primary conductors that will require replacement. One project was undertaken in 2008, and two will be undertaken in 2009; leaving thirteen No. 6 copper projects to be undertaken in future budget years.

Five pole-line replacement projects have been identified for Kincardine; one of which will be undertaken in 2009; and the balance in future budget years.

Ripley

Ripley has an overhead system with minimal underground plant. Traditional levels of maintenance and capital works should be sufficient to maintain the system.

The focus for 2008 will be targeting some of the worst poles for replacement under our Capital pole replacement program. Two projects to replace No. 6 copper conductors have been identified, and will be undertaken in future budget years.

One pole-line replacement projects have been identified for Ripley which will be undertaken in a future budget year.

Lucknow

Lucknow is an overhead system. Lucknow has a relatively new substation and some new primary feeders. Nine projects to replace No. 6 copper conductors have been identified, and one will be undertaken in 2009.

Three pole-line replacement projects have been identified for Lucknow which will be undertaken in future budget years.

Wingham

The distribution system in Wingham is mostly overhead. Poles and lines are in poor condition and require attention. Data collection and mapping will contribute for developing a longer-range work plan for this system.

In 2009, the Wingham MS1 substation will be refitted with new reclosers to effectively allow feeders to be switched out under storm conditions and to protect the substation transformer.

Seven projects to replace No. 6 copper conductors have been identified, and one will be undertaken in 2009; the balance will be undertaken in future budget years.

Two pole-line replacement projects have been identified for Harriston; one of which will be undertaken in 2009; and the balance in future budget years.

Teeswater

The Teeswater distribution system is overhead. Teeswater has a relatively new substation.

Three projects to replace No. 6 copper conductors have been identified, and these will be undertaken in future budget years.

Four pole-line replacement projects have been identified for Teeswater; one of which will be undertaken in 2009; and the balance in future budget years.

Mildmay

Mildmay has an overhead system with some pockets of underground residential distribution. Traditional levels of maintenance and capital works should be sufficient to maintain the system.

Walkerton

The Walkerton overhead system is in good condition. New underground residential distribution has been added in recent years, however load growth is low.

In 2008 the Walkerton MS1 substation will be replaced as the existing substation under-oil insulation is failing.

Five projects to replace No. 6 copper conductors have been identified, one of which will be undertaken in 2009.

One pole-line replacement project has been identified; which will be undertaken in future budget years.

Palmerston

Palmerston is an overhead system, but is seeing some growth in the form of a new residential underground subdivision.

In 2008, the Palmerston substation will be refitted with new reclosers to effectively allow feeders to be switched out under storm conditions and to protect the substation transformer. The substation yard will also require a new ground grid. The present ground gradient does not meet the minimum requirements of the Electrical Safety Code.

In 2008 one project to replace 27 secondary trench boxes for public safety will be undertaken. One project to replace No. 6 copper conductors has been identified, and will be undertaken in future budget years.

Harriston

Harriston is an overhead system, with small pockets of underground distribution.

In 2008 porcelain insulators will be replaced. Also in 2008 a spare substation transformer will be acquired for installation at Harriston MS. The installation at the site will not occur until 2009.

Three pole-line replacement projects have been identified for Harriston; one of which will be undertaken in 2009; and the balance in future budget years.

Clifford

Clifford is a small overhead system; with minimal underground plant. Normal practices are adequate to maintain system reliability.

Elmwood

This is a small overhead system; with minimal underground plant. Normal practices are adequate to maintain system reliability.

Hanover

The system is 75 percent overhead with the balance underground. Overall condition of the system is fair to good.

Fourteen projects to replace No. 6 copper conductors have been identified, and one will be undertaken in 2009. No. 6 copper primary conductors need to be replaced due to age and brittleness of the conductors.

Seven pole-line replacement projects have been identified for Hanover. One pole-line replacement will be undertaken in 2009.

Neustadt

Neustadt is small overhead system. Two projects to replace No. 6 copper conductors have been identified, and will be undertaken in future budget years.

Different Customer & Financial Technologies

Each former utility had its own customer billing system (four different products). Therefore, it was impractical to benefit from the efficiencies of handling customer inquiries through a central call centre. Similarly the financial systems for each former entity were different, including some manual systems.

Distribution System Asset Records

Generally, the former utilities had little, if any, documentation on the distribution system assets. Information that was available was usually limited to map(s) of the system. There were no records containing such information as age of equipment, years in service, fuse/disconnect ratings, equipment manufacturer, PCB surveys, condition assessments, failure history, transformer connections, etc.

In addition to the operating challenges that this lack of information presents, it prevents the development of a cost effect asset management plan that addresses growth, line loss minimization, reliability performance measures, and financial capabilities of the Company.

Inventory

Inventory was distributed over multiple locations as well. None of the former utilities had dedicated inventory personnel. This resulted in the inefficient use of inventory, poor loss prevention control, lost opportunities to benefit from the cost savings of central purchasing, and the duplication of materials.

Condition of Distribution Systems

The condition of the inherited distribution systems in many communities was poor to fair. While some former utilities had made reasonable investments in their systems, the majority appeared to have taken the approach of "If it isn't broken, don't fix it".

Whether this was a result of local pressures to kept rates down is not known but the lack of investment in capital and maintenance projects is most evident in the following categories:

- 1 • Tree Trimming
- 2 o The tree trimming performed was minimal and need to be performed every year.
- 3 • Substation Maintenance
- 4 o A regular schedule of maintenance did not exist in most communities.
- 5 • Pole Replacements
- 6 o A substantial number of poles are beyond their useful life and need replacing.
- 7 o Affects the reliability of the distribution system.
- 8 • #6 Copper Conductor
- 9 o In the past #6 Copper primary wire was an inexpensive solution for extending
- 10 power lines to areas with small energy demands. These areas are now
- 11 experiencing load growth and feeder extensions off the #6 primary wire. The
- 12 wire has grown brittle and is undersized for the average load.
- 13
- 14 o Due to its brittle nature, #6 copper wire poses a public and worker safety issue
- 15 should the wire break and fall. Westario Power has experienced incidents of #6
- 16 copper wire breaking and falling to the ground unrelated to weather events.
- 17 These events are a potential and significant safety risk to line workers and the
- 18 public. As a result, efforts have been made throughout the industry to remove #6
- 19 copper wire from service.
- 20
- 21 o Two other significant operational issues arise for the continued use of #6 copper
- 22 wire:
- 23
- 24 ▪ Line Losses
- 25 Because of the small cross-sectional diameter of the wire, this wire has a
- 26 high electrical resistance. As loads increase, and more current passes
- 27 through #6 cooper wire sections, line resistance losses increase. Energy
- 28 losses from wire resistance usually lead to heating of the wire. This
- 29 resistance is proportional to the square of the current passing through the
- 30 line.
- 31

1 ▪ Improper Fault Current Protection

2 As described above, the small cross-sectional diameter of the wire means
3 high electrical resistance. Fault protection equipment at the substation is
4 designed to sense a line fall when there is a sudden and continuous
5 increase in line current. The high wire resistance effectively attenuates
6 the line currents. As a result the fault current protection equipment at the
7 substation does not always sense the fault current, and the substation
8 fault protection devices do not operate to isolate the line.

- 9
- 10 o Worker and public safety is highly compromised when the high resistance of the
11 #6 copper wire causes fault current protection equipment to not sense the high
12 line currents and not isolate the fallen lines.

13

14 **Action Plans to Address Issues**

15

16 **Managing and Coordinating Staff**

17 Centralizing all staff, along with the fleet and inventory was accomplished in 2007 with the
18 Company's new facility in Walkerton (Exhibit 2, Schedule 3, Tab 4).

19

20 **Different Skill Sets**

21 Since inception, the Company has invested in the training and skills development of staff. The
22 line staff, in particular, have been brought to the same level of proficiency on all distribution
23 system voltages used in the various communities and standardized work maintenance and
24 construction practices.

25

26 **Different Customer & Financial Technologies**

27 The Company has installed one computer information system with fully integrated customer
28 billing/inquiry, financial, project management, purchasing, device management and inventory
29 modules.

30

1 Customer inquiries are now addressed through a central call centre with the capabilities of
2 tracking the customer service related Service Quality Indicator (SQI) targets.

3 4 **Distribution System Asset Records**

5 Starting in 2008, the Company began a three year program to collect data on all installed
6 distribution system assets.

7
8 This program will permit the development of an effect asset management plan that addresses
9 growth, line loss minimization, reliability performance measures, and financial capabilities of the
10 Company. Westario Power will be pleased to submit this plan with its next rate application.

11 12 **Inventory**

13 With the move to the Company's new facilities in 2007, inventory is now centralized. This has
14 lead to better inventory management as evidenced by the decrease in inventory write-offs from
15 a previous high of high of 12% of inventory to 2%.

16 17 **Condition of Distribution Systems**

18 Investments made by Westario Power in capital and maintenance programs since 2000, have
19 raised the general condition of the distribution systems to the status of fair to good. More
20 investment is needed and this application details the continued efforts proposed in these areas.

21
22 With reference to the specific issues identified above, the following programs have been put in
23 place:

24 25 • **Tree Trimming**

- 26 o Tree trimming in all communities is carried out on a rotating three year schedule.
27 Trees are trimmed sufficient to provide the required clearances for the three year
28 timeframe.
- 29 o Work crews were provided arborist training to improve their tree trimming skills.
30 The result has been that trees are now trimmed in a manner specific to the tree

species, yet still provide the clearances needed to last the timeframe, in a fashion that is generally acceptable to the public.

- Substation Maintenance

- o All substations are now maintained on a three year schedule. The work performed is documented and any identified issues are addressed.

- Pole Replacements

- o The Company allocates a capital pole replacement budget on an annual basis. Poles are prioritized for replacement based upon age, condition and potential adverse impact on the reliability of the distribution system.

- o Once the distribution system asset records are complete, the Company's asset management plan can be completed and the full extent of its pole replacement program identified.

- #6 Copper Conductor

- o Continuing and expanding on the capital projects carried out over recent years, the 2009 Capital Works identified in this application proposes a more aggressive plan to replace #6 copper.

- o Additionally, other past and proposed capital projects address line losses by removing undersized and over utilized assets from service and replacing them with larger capacity and more robust plant. Examples of these projects are as follows:

- Pole line rebuild projects seeks to replace undersized main feeders with new larger capacity feeders, thus reducing loss.

- The 5 kV cable replacement program is a similar issue to that the No. 6 copper issue except that the work is replacement of underground cables and transformers. The old style inefficient and overloaded transformers are displaced and replaced with new, more efficient transformers.

- A project to replace old thermal demand poly-phase meters with new electronic demand meters. Meter error accuracy in old mechanical meters will be reduced. Mechanical meters tend to register lower

1 readings as they fail, unlike electronic meters which cease to display
2 upon failure.

3
4 These initiatives will retire undersized feeder and conductors and deploy more
5 accurate meters into the distribution system. With the impending deployment of
6 smart meters, more accurate information will become available to compare
7 delivered electricity to actual consumption.

LDC's Distribution License

The following attachment is the LDC's Distribution License.



Electricity Distribution Licence

ED-2002-0515

Westario Power Inc.

Valid Until
March 17, 2024

Mark C. Garner
Secretary
Ontario Energy Board

Date of Issuance: March 18, 2004

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

1 Definitions

In this Licence:

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

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

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

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

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

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

“Licensee” means: Westario Power Inc.;

“Market Rules” means the rules made under section 32 of the Electricity Act;

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

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

“regulation” means a regulation made under the Act or the Electricity Act;

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

“**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;

“**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.

2 Interpretation

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.

3 Authorization

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

- a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence;
- 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
- c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act.

4 Obligation to Comply with Legislation, Regulations and Market Rules

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

5 Obligation to Comply with Codes

- 5.1 The Licensee shall at all times comply with the following Codes (collectively the “Codes”) approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:
- a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;
 - b) the Distribution System Code;
 - c) the Retail Settlement Code; and
 - d) the Standard Supply Service Code.
- 5.2 The Licensee shall:
- a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and
 - b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Obligation to Provide Non-discriminatory Access

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

7 Obligation to Connect

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

- a) the building lies along any of the lines of the distributor's distribution system; and
- b) the owner, occupant or other person in charge of the building requests the connection in writing.

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

- a) the building is within the Licensee's service area as described in Schedule 1; and
- b) the owner, occupant or other person in charge of the building requests the connection in writing.

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

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

8 **Obligation to Sell Electricity**

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

9 **Obligation to Maintain System Integrity**

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

10 **Market Power Mitigation Rebates**

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

11 Distribution Rates

- 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.

12 Separation of Business Activities

- 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.

13 Expansion of Distribution System

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

- 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.

14 Provision of Information to the Board

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

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

- 14.3 The licensee shall inform the Board as soon as possible of any material changes to the service agreement with Westario Power Services Inc. (the "Service Agreement").

- 14.4 If either party to the Service Agreement provides notice of its intention to exercise a right to terminate or discontinue any services under the services agreement, the Licensee shall:

- a) Immediately notify the Board in writing of the notice; and

- b) provide a plan to the Board as soon as possible, but no later than ten (10) days after the receipt of the notice, as to how the affected distribution services will be maintained in compliance with the terms of this licence.

14.5 In the event of termination of the Service Agreement for any reason, the Licensee shall:

- a) ensure there is no interruption of distribution services to the consumers as a result of the termination,
- b) notify the Board of the name of the new company that will provide the distribution services, and
- c) file with the Board the distribution services agreement with the new company.

15 Restrictions on Provision of Information

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.

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

- a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;
- b) for billing, settlement or market operations purposes;
- c) for law enforcement purposes; or
- d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.

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

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

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

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

- a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;
- b) publish information which will make its customers aware of and help them to use its dispute resolution process;
- c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee’s premises during normal business hours;
- d) give or send free of charge a copy of the process to any person who reasonably requests it; and
- e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective.

17 Term of Licence

17.1 This Licence shall take effect on December 18, 2004 and expire on December 17, 2024. The term of this Licence may be extended by the Board.

18 Fees and Assessments

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

19 Communication

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

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

- 19.3 All written communication is to be regarded as having been given by the sender and received by the addressee: 96
- a) when delivered in person to the addressee by hand, by registered mail or by courier; 97
 - b) ten (10) business days after the date of posting if the communication is sent by regular mail; and 98
 - c) when received by facsimile transmission by the addressee, according to the sender's transmission report. 99

20 Copies of the Licence 100

- 20.1 The Licensee shall: 101
- 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 102
 - 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. 103

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

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

1. The Town of Hanover as at December 30, 1999.
2. The Village of Neustadt as at December 30, 1999, now part of the Township of West Grey.
3. The Village of Clifford, the Town of Harriston and the Town of Palmerston as at December 31, 1998, now part of the Town of Minto.
4. The Town of Walkerton and Village of Elmwood, as at January 1, 1986, now part of the Municipality of Brockton.
5. The former Village of Ripley as at December 31, 1994 and the former Village of Lucknow, as at December 31, 1998, now part of the Township of Huron-Kinloss.
6. The former Town of Kincardine as at January 2, 1995, now known as Ward 1 of the Municipality of Kincardine.
7. The former Town of Port Elgin and the former Town of Southhampton as at December 31, 1998, now part of the Town of Saugeen Shores.
8. The former Village of Mildmay and the former Village of Teeswater as at December 31, 1997, now part of the Municipality of South Bruce.
9. The former Town of Wingham as at December 31, 2000, now part of the Township of North Huron, with the exclusion of the customer located at 200 Water Street.

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

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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.

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

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SCHEDULE 3 LIST OF CODE EXEMPTIONS

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

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

1 Definitions and Interpretation

In this Licence,

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

“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;

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

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

2 Information Given to IMO

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:

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

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

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

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.

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.

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.

3 Pass Through of Rebate

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:

- 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;
- 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
- c embedded distributors to whom the distributor distributes electricity.

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.

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:

“ONTARIO POWER GENERATION INC. rebate”

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.

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

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.

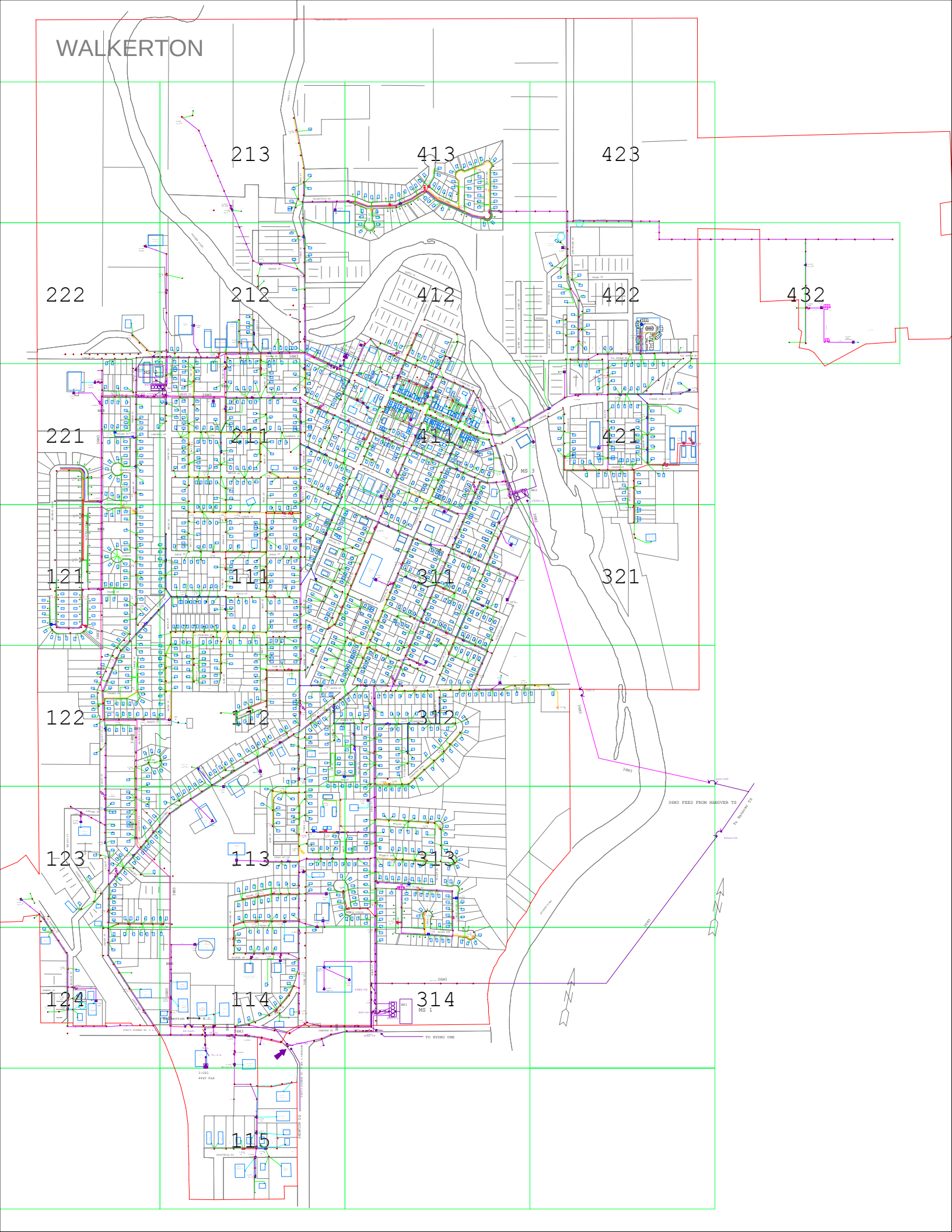
1 **Map of LDC's Distribution System**

2

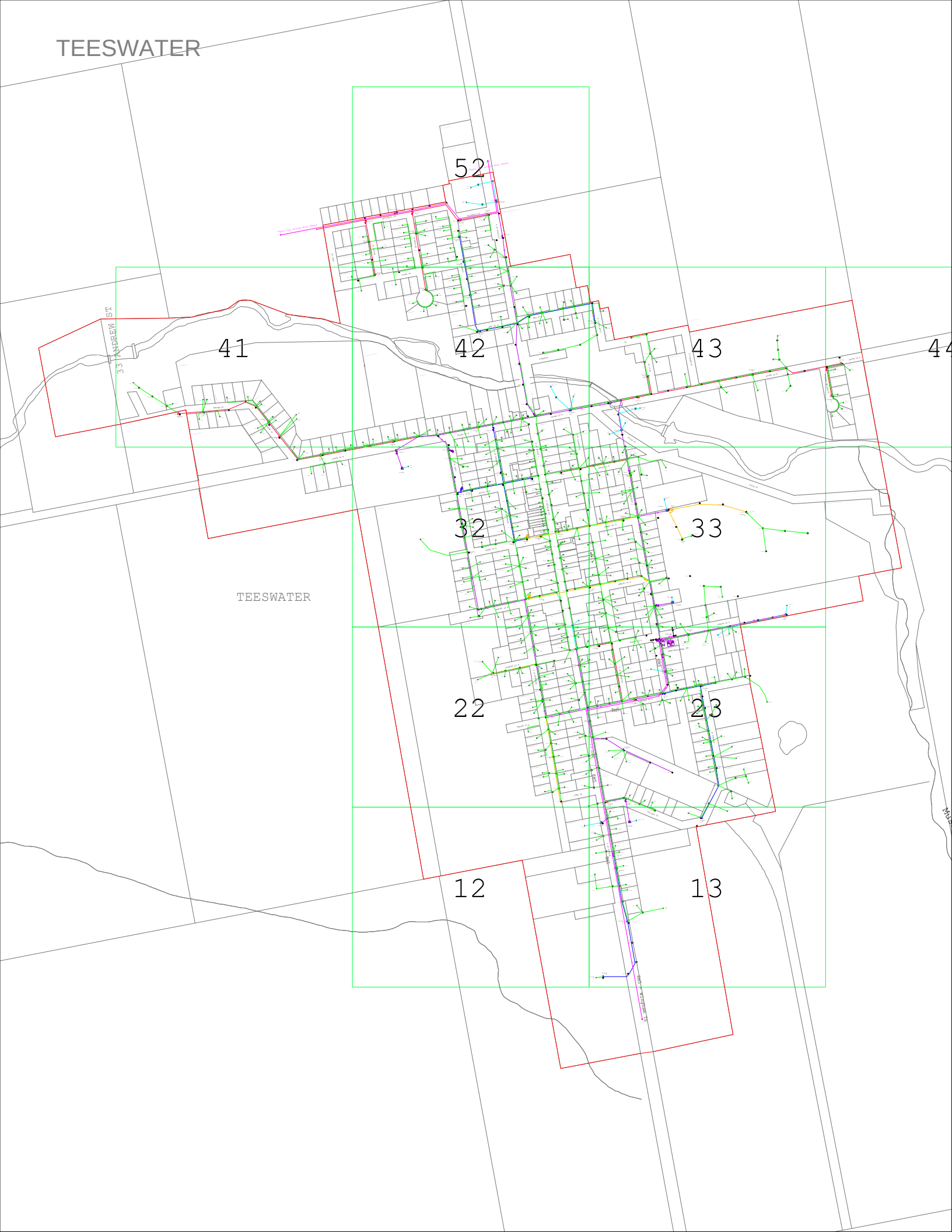
3 The following attachment is the Map of the LDC's Distribution System.

4

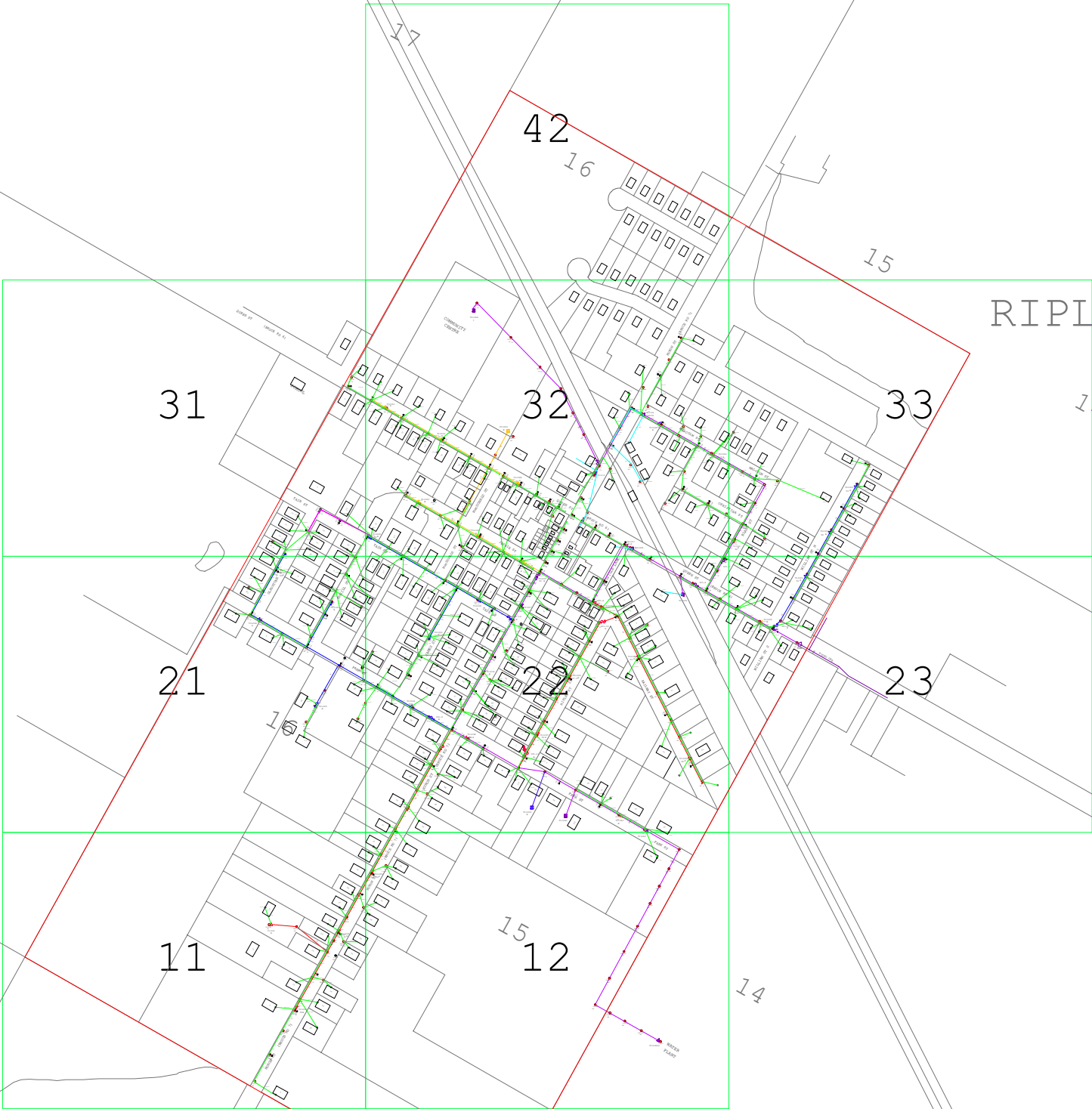
WALKERTON



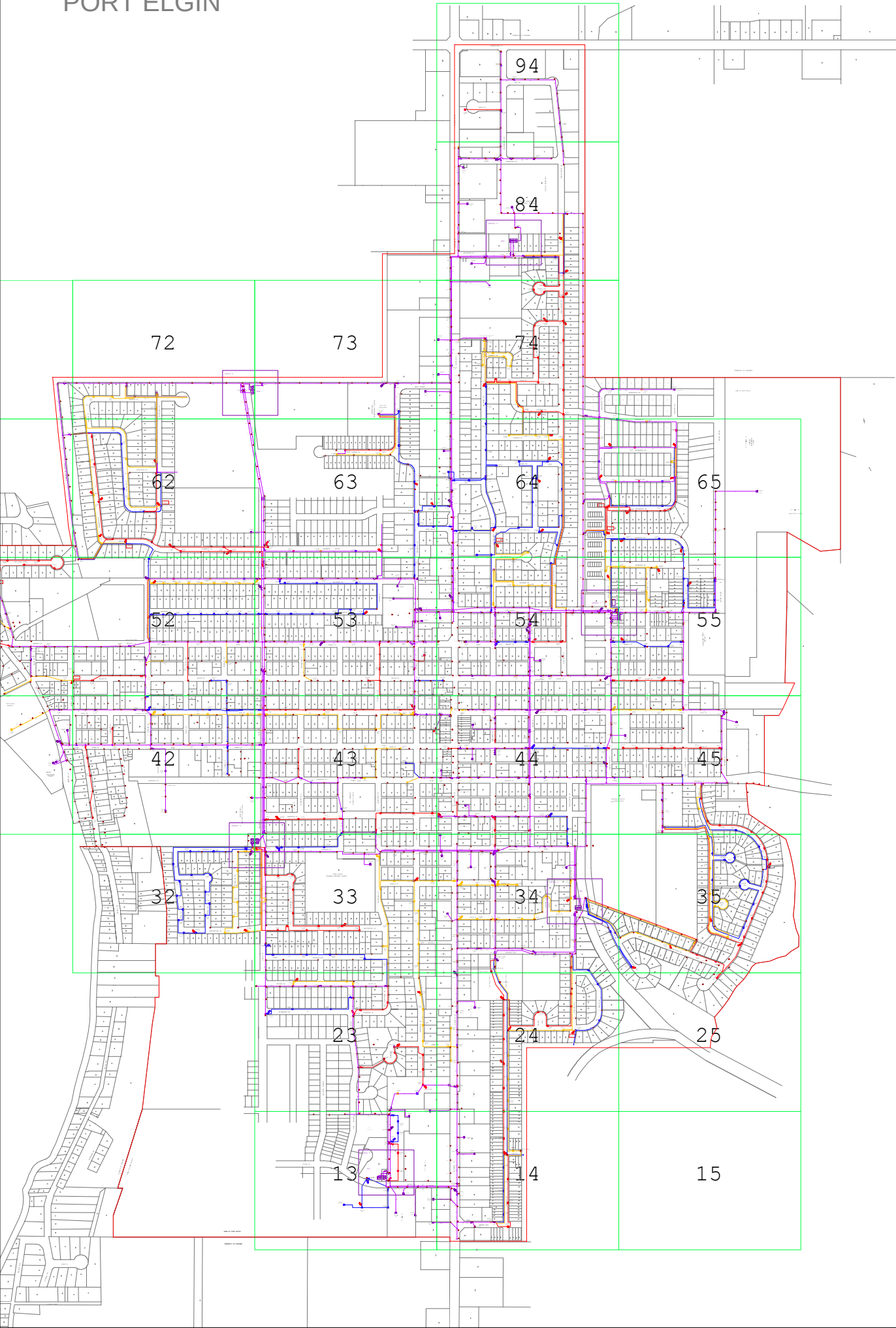
TEESWATER



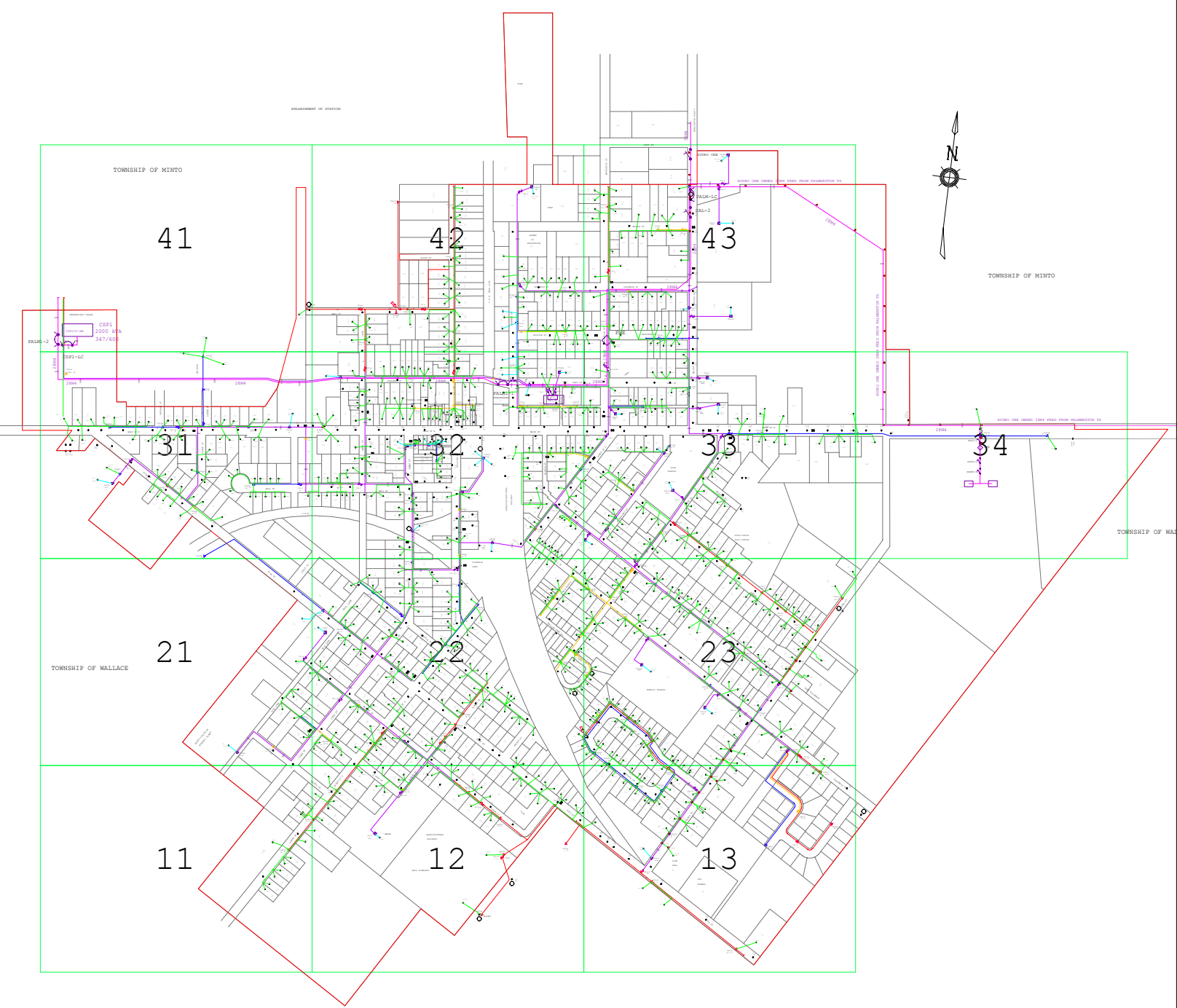
RIPLEY



PORT ELGIN



PALMERSON



NEWSTADT

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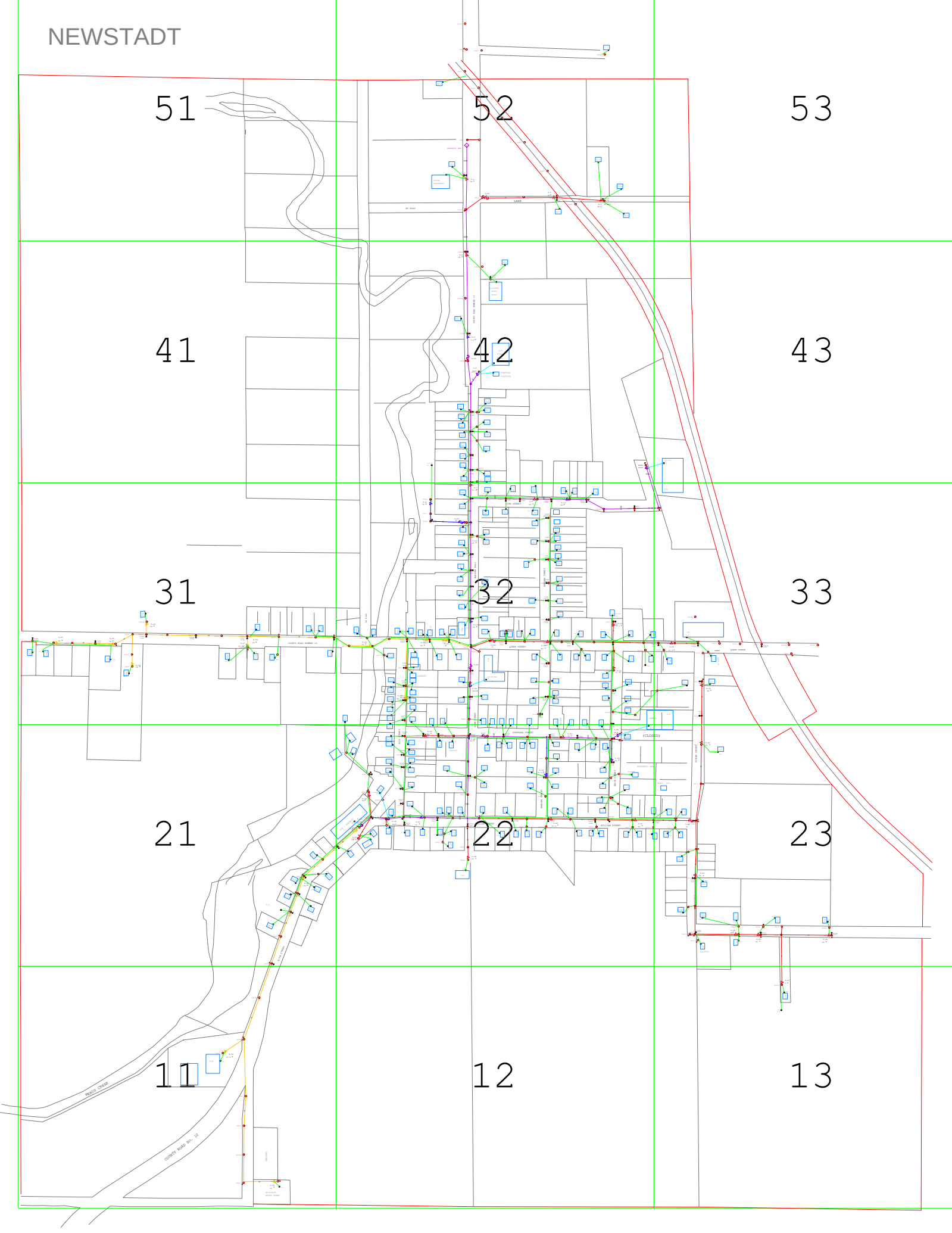
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MILDMAY

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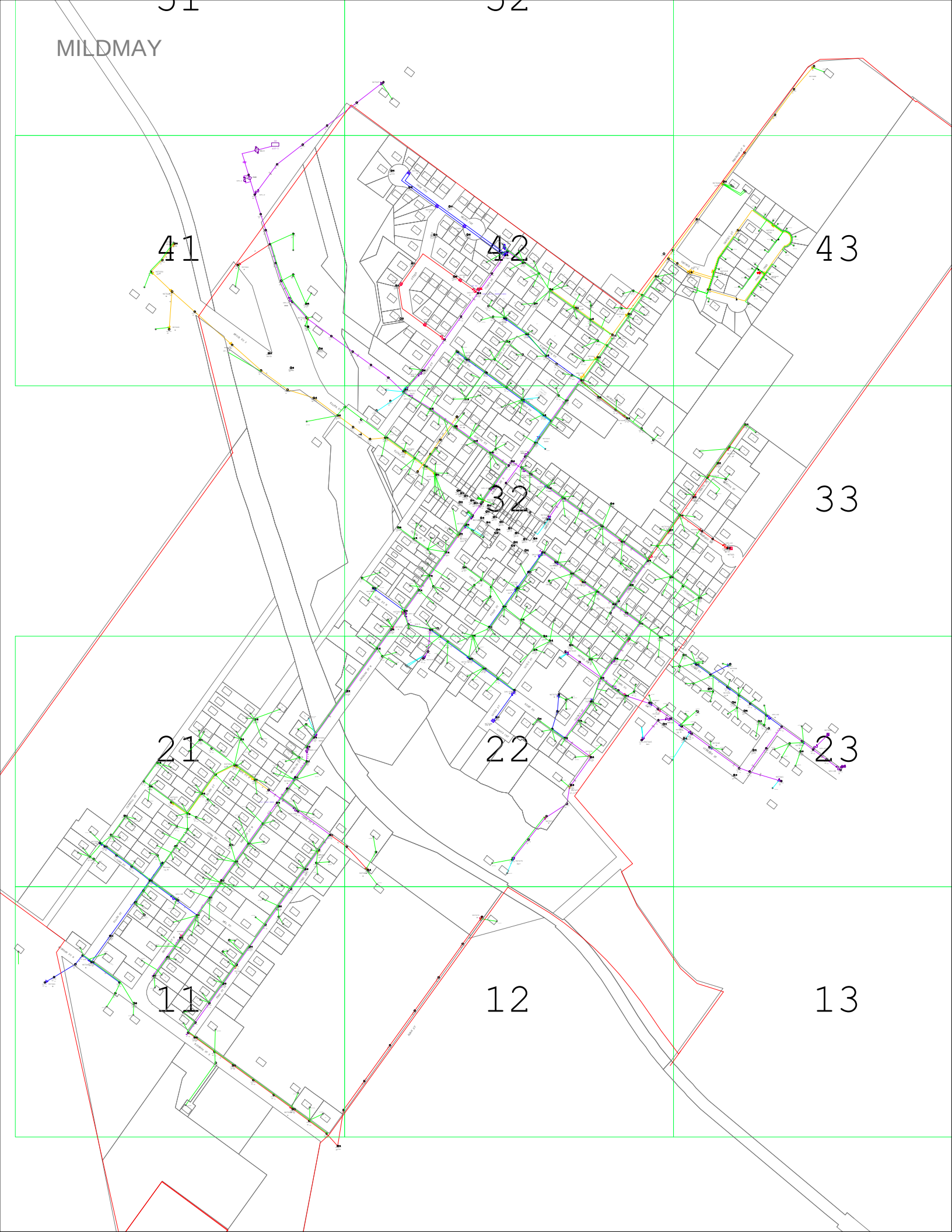
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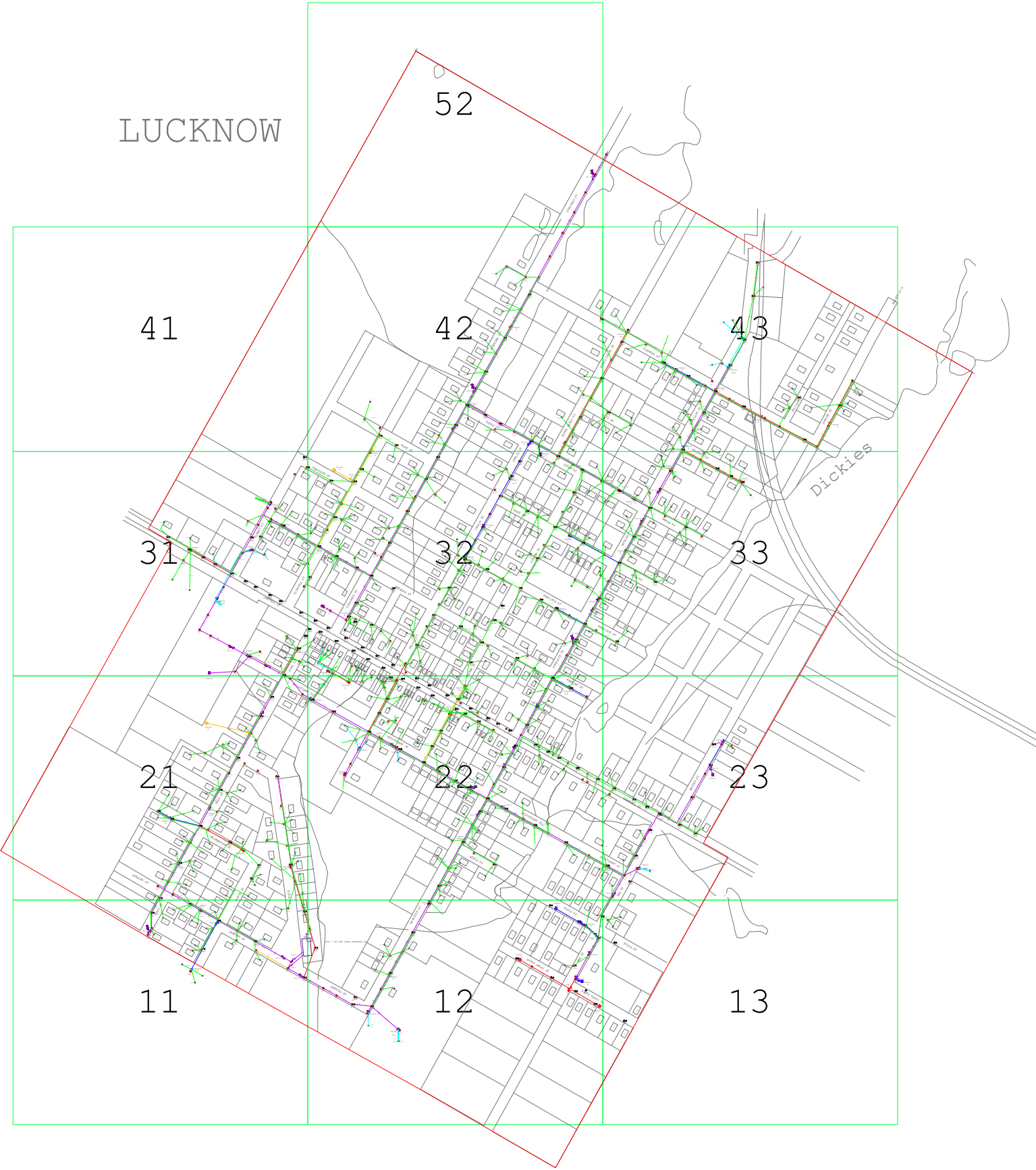
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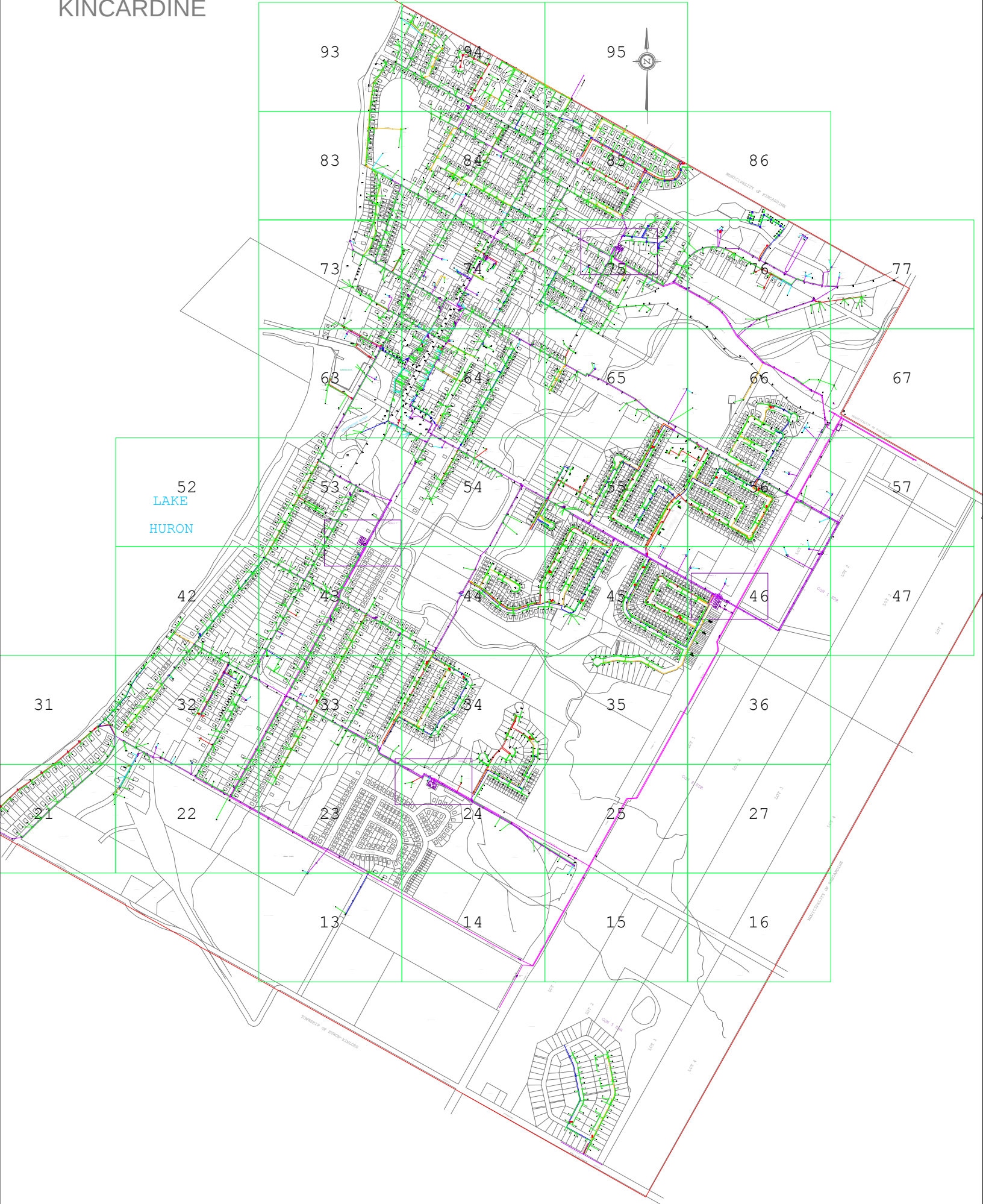
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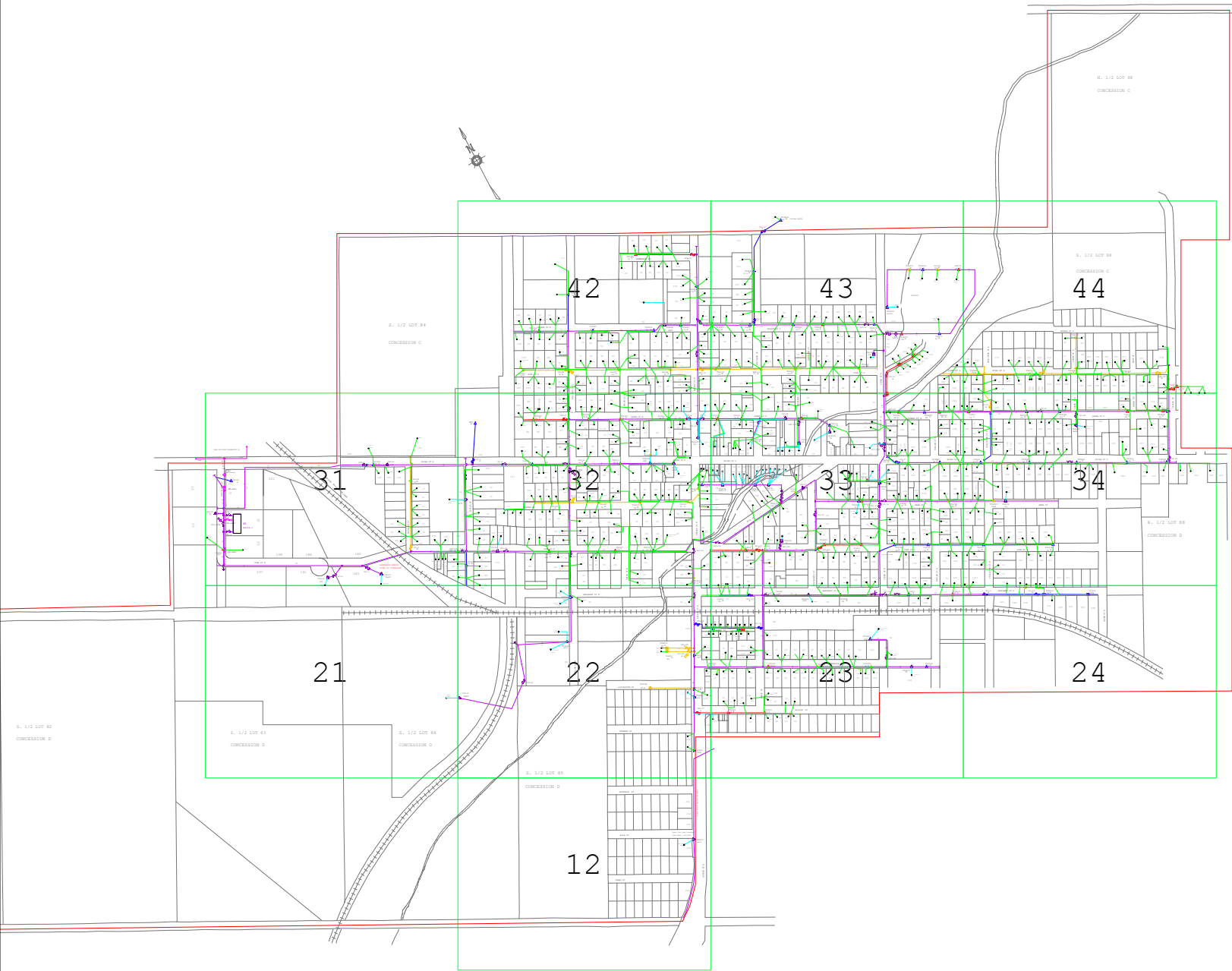




KINCARDINE



HARRISTON



ELMWOOD

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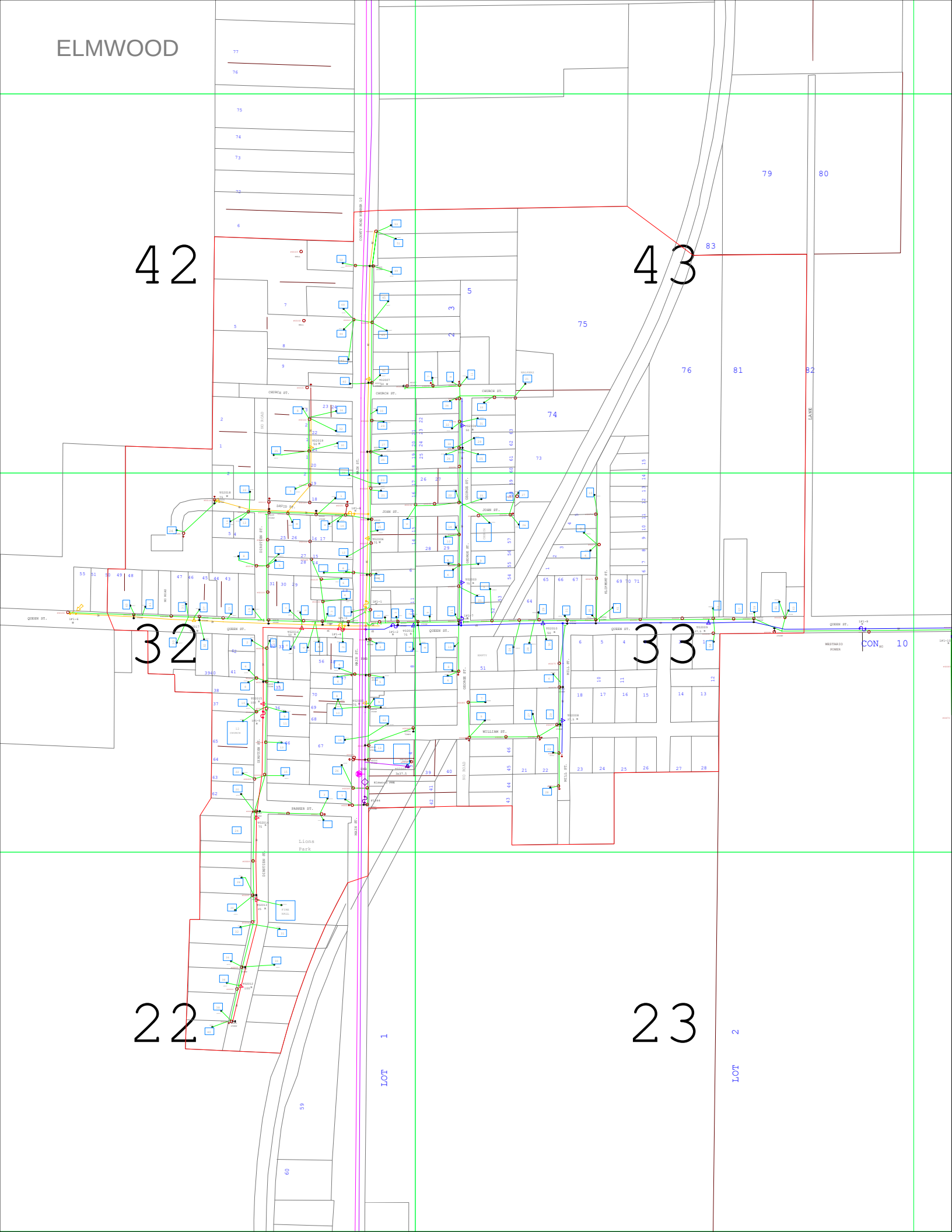
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LOT 1

LOT 2



CLIFFORD

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TOWNSHIP OF HOWICK

LOT 58
CONCESSION 'C'



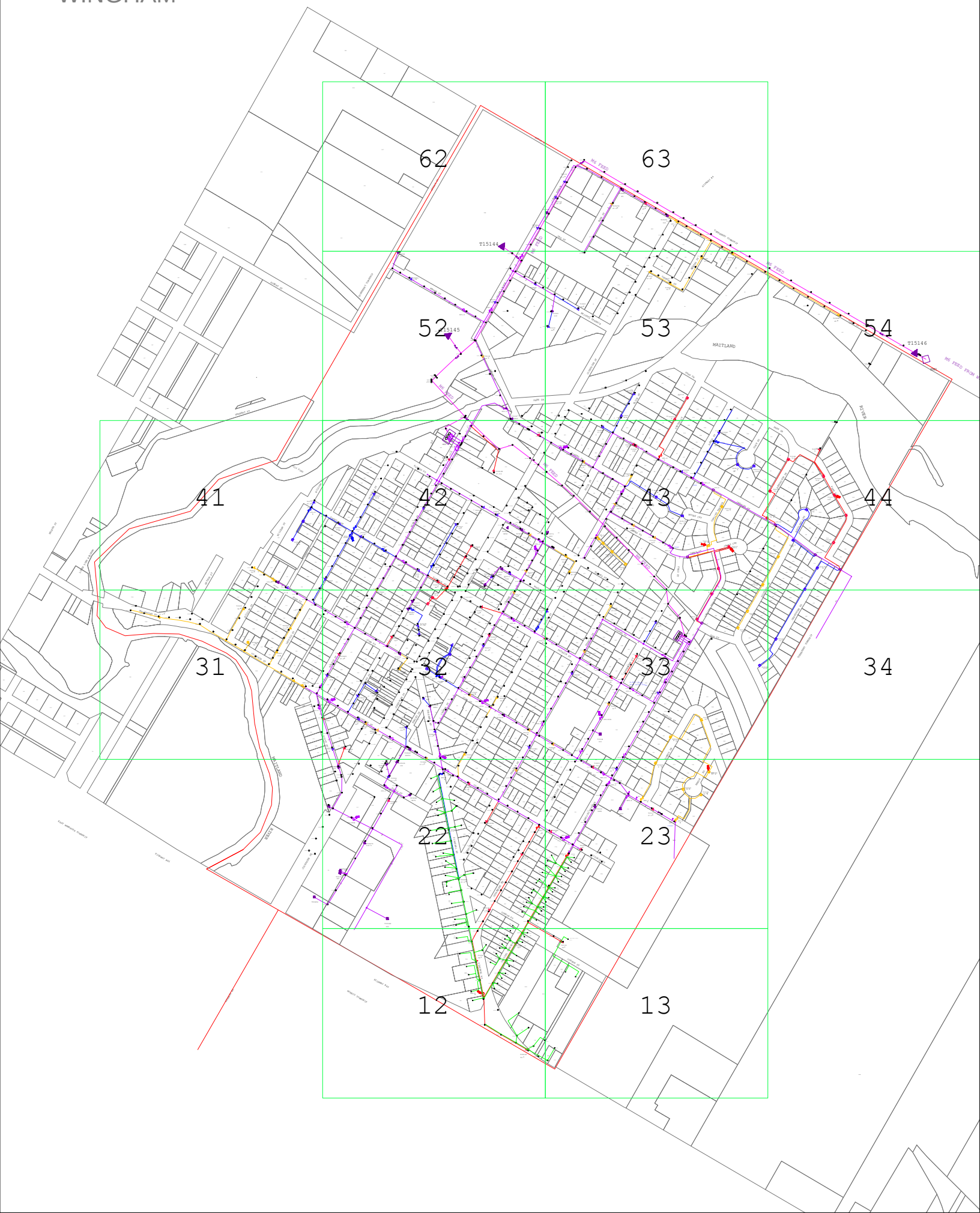
TOWNSHIP OF MINTO

LOT 61
CONCESSION 'D'

LOT 61
CONCESSION 'C'

LOT 61

WINGHAM

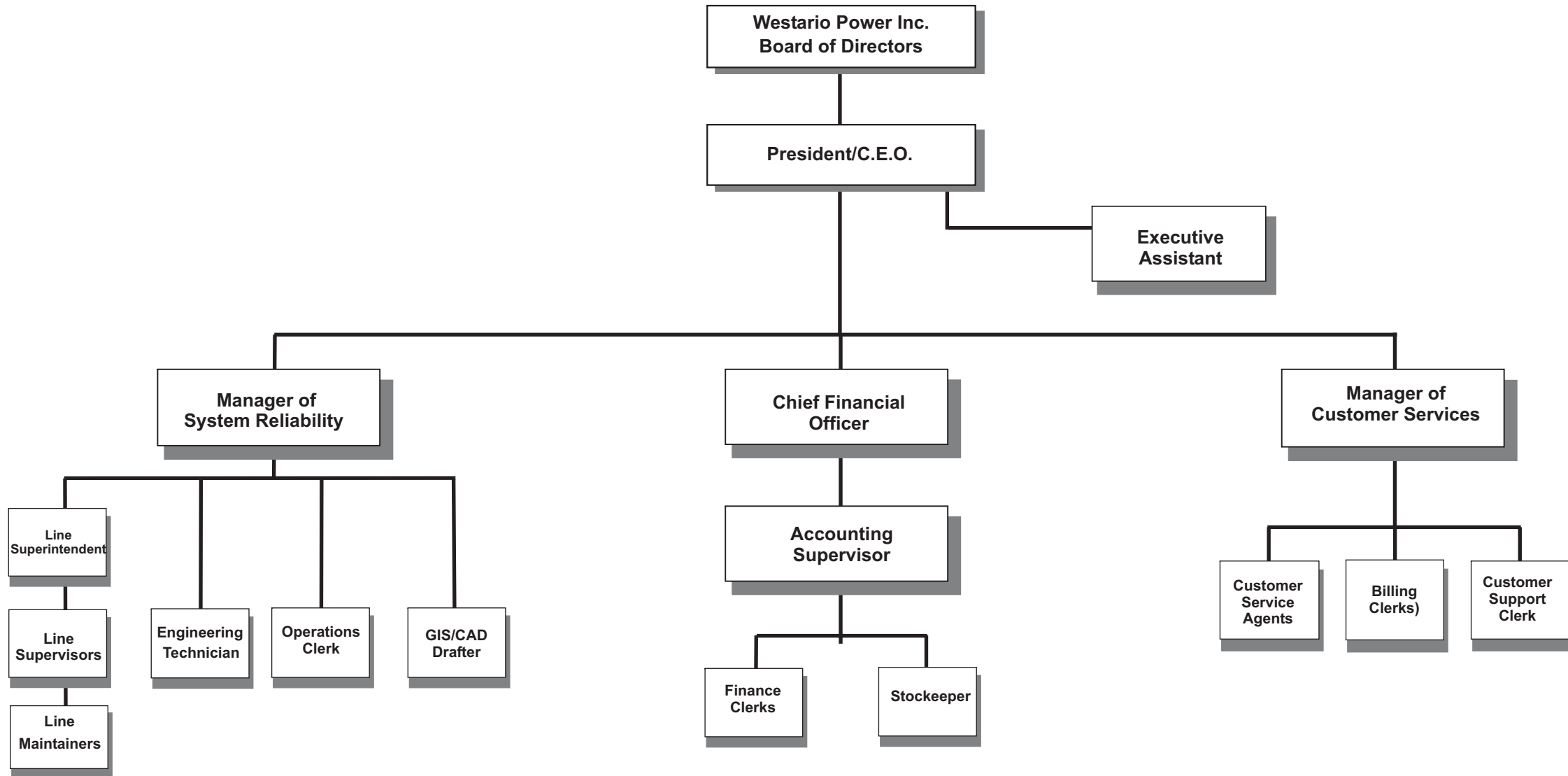


Utility Organizational Chart

The following attachment is the Utility Organizational Chart.



Westario Power Inc.



Corporate Entities Relationships Chart

On January 1, 2008, Westario Power Inc., Westario Power Holdings Inc. and Westario Power Services Inc. amalgamated to form a single corporation that carries on as a distribution company under the name Westario Power Inc. The shareholders of Westario Power Holdings Inc. are the shareholders of the amalgamated company. Therefore, WPI is the sole corporate entity.

Planned Changes in Corporate or Operational Structure

There are no planned changes in Corporate or Operational Structure at this time.

Conditions of Service/Service Charges

The following attachment is the Conditions of Services/Service Charges.

CONDITIONS OF SERVICE

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[Request For Connection Form](#)

SECTION 1 INTRODUCTION

1.1 Identification of Distributor and Territory

The Distributor is a corporation, incorporated under the laws of the Province of Ontario to distribute electricity.

The Distributor is licensed by the Ontario Energy Board “OEB” to supply electricity to Customers as described in the Transitional Distribution License and thereafter by the Distribution License issued to the Distributor by the OEB. Additionally there are requirements imposed on the Distributor by the various codes referred to in the License and by the [Electricity Act](#) and the [Ontario Energy Board Act](#).

The Distributor is limited to operate distribution facilities within their Licensed Territory as defined in the Distribution License.

1.1.1 General

Nothing contained in this document or in any contract for the supply of electricity by the Distributor shall prejudice or affect any rights, privileges, or powers vested in the Distributor by law under any Act of the Legislature of Ontario or the Parliament of Canada, or any regulations thereunder.

All operations performed by the distributor and its agents shall be performed within the rules and regulations set out by the appropriate authorities including but not limited to: ESA, Ministry of Labour, Ministry of Transportation, etc.

The Distributor will normally provide one electrical service to each customer location at a nominal service voltage.

Modifications to an existing service must comply with the requirements of the standards in effect at the time of the modifications.

The customer or their authorized representative must make application for new or upgraded electric services and temporary power services.

The customer or their representative shall consult with the Distributor concerning the availability of supply, the voltage of supply, service location, metering and any other details. These requirements are separate from and in addition to those of the Electrical Inspection Authority. The Distributor will confirm, in writing, the Characteristics of Electric Supply available at a specific site.

The customer is required to provide the Distributor sufficient lead-time in order to ensure:

- (a) *the timely provision of supply to new and upgraded premises or*
- (b) *the availability of adequate capacity for additional loads to be connected in existing premises.*

If special equipment is required or equipment delivery problems occur then longer lead times may be

necessary. The customer will be notified of any extended lead times.

Customers will be required to pay the cost of repair or replacement of the Distributors' equipment that has been damaged through the customers' action or neglect.

The supply of electricity is conditional upon the Distributor being permitted and able to provide such a supply, obtaining the necessary apparatus and material, and constructing works to provide the service. Should the Distributor not be permitted to supply or not be able to do so, it is under no responsibility to the customer whatsoever.

The customer shall not build, plant or maintain or cause to be built, planted or maintained any structure, tree, shrub or landscaping that would or could obstruct the running of distribution lines, endanger the equipment of the Distributor, interfere with the proper and safe operation of the Distributor's facilities or adversely affect compliance with any applicable legislation in the sole opinion of the Distributor.

Prior to commencing any service work, the customer must consult with the Distributor to ensure compliance with current requirements.

The customer is responsible for selecting a qualified/competent contractor. Careful selection of a contractor can significantly affect the cost of a project. The Distributor shall be consulted prior to the selection of a mutually acceptable contractor.

The customer maintains the responsibility to ensure that all work is done in accordance with the distributor's design and technical standards and specifications.

The Distributor, at the expense of the customer, reserves the right to inspect the work throughout the duration of the project, and the Contractor shall supply him such accommodations as he may require. The Inspector shall request that the Contractor stop work at any time he feels the Contractor is not proceeding in accordance with these "conditions of service". The customer shall confer with the Distributor before work recommences to mitigate undue cost and construction delays for the project.

Customers may be required to pay Capital Contributions for the addition of new and upgraded electrical services in accordance with the Economic Evaluation process as defined in the Distribution System Code.

1.2 Related Codes and Governing Laws

The Distributor is limited in its scope of operation by the:

1. *Electricity Act, 1998*
www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98e15_e.htm
2. *Ontario Energy Board Act, 1998*
www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98o15_e.htm

3. *Distribution Licence*
[Licence Numbers](#)
4. *Affiliate Relationships Code*
<http://www.collus.com/images/stories/Documents/ARC.pdf>
5. *Distribution System Code*
<http://www.collus.com/images/stories/Documents/DSC.pdf>
6. *Retail Settlements Code*
<http://www.collus.com/images/stories/Documents/RSC.pdf>
7. *Standard Service Supply Code*
<http://www.collus.com/images/stories/Documents/SSSC.pdf>
8. *Transmission System Code*
<http://www.collus.com/images/stories/Documents/TSC.pdf>
9. *Ontario Regulation 22/04 - Electrical Distribution Safety*
http://www.e-laws.gov.on.ca/html/source/regs/english/2004/elaws_src_regs_r04022_e.htm
10. *Measurement Canada*
http://strategis.ic.gc.ca/epic/site/mc-mc.nsf/en/h_lm03862e.html

In the event of a conflict between this document and the Distribution Licence or regulatory Codes issued by the OEB, or the [Electricity Act](#), the provisions of the Act, the Distribution License and associated regulatory Codes shall prevail.

When planning and designing for electricity service, Customers and their agents must refer to all applicable Provincial and Canadian electrical codes, and all other applicable federal, provincial, and municipal laws, regulations, codes and by-laws to also ensure compliance with their requirements. The work shall be conducted in accordance with the Ontario Occupational Health and Safety Act, the Regulations for Construction Projects and the E&USA (or the OHSC Safety) rulebook.

1.3 Interpretations

In these Conditions, unless the context otherwise requires:

- *Headings and underlining are for convenience only and do not affect the interpretation of these Rules.*
- *Words referring to the singular include the plural and vice versa.*
- *Words referring to a gender include any gender.*

1.4 Amendments and Changes

The provisions of these Conditions of Service and any amendments made from time to time form part of any Contract made between the Distributor and any connected Customer, Generator or their agents.

In the event of changes to this Conditions of Service, a Public notice shall be made in the form of either a notice in the local newspaper, or a notice on the Distributors' Website.

The Customer is responsible for contacting the Distributor to ensure that the Customer has, or to obtain the current version of the Conditions of Service. The Distributor may charge a reasonable fee to recover costs for providing the Customer with more than one copy of this document.

1.5 Contact Information

The Distributor and its agents can be contacted during normal working hours. Please refer to the Contact Listing in the Appendices for phone number of the Local Distribution Company servicing your area.

1.6 Customer Rights

In those instances where the Customer will own their secondary or primary service, the Customer has the right to hire a Contractor to supply and install the service.

The customer has the right to demand identification from any person purporting to be an authorized agent or employee of the distributor.

A customer, who believes that he has suffered damages to his property or equipment as a result of negligence on the part of the Distributor, may submit a written claim for damages to the Distributor. The Distributor will investigate the claim and respond in writing within 10 business days of the receipt of the claim.

1.7 Distributor Rights

In those instances where the Customer has the authority to hire a Contractor to construct plant which will become part of the Distributors' system, the Distributor shall have the right to require the Contractor to submit proof of previous experience and satisfactory performance, and, the Distributor shall have the right to investigate such proof and approve the Contractor prior to the Owner awarding a contract for the work to the Contractor.

The Distributor shall have access to Customer property in accordance with section 40 of the [Electricity Act, 1998](#).

1.8 Disputes

If, following good faith negotiations between a customer or other market participant and the Distributor, a resolution cannot be reached, the dispute may be submitted to a dispute resolution process.

Any dispute which shall arise between the Distributor and a customer(s) and other market participants subject to the terms of these Conditions of Service concerning the rights, duties or obligations of the Distributor or others subject to these Conditions of Service, shall be subject to the following dispute resolution procedure:

Mediation

- Either party (the “Initiating Party”) may invoke the dispute resolution procedure by sending a written notice to the other party (the “Respondent Party”) describing the nature of the dispute and designating a representative of the Initiating Party with appropriate authority to be its representative in negotiations relating to the dispute. The responding Party shall, within five business days of the receipt of such notice, send a written notice to the Initiating Party, designating a representative of the Responding party with the appropriate authority to be its representative in negotiations relating to the dispute.
- Within ten business days of the receipt by the Initiating Party of the written notice of the Responding Party the designated representatives shall enter into good faith negotiations with a view to resolving the dispute. If the dispute is not resolved in thirty days of the commencement of such negotiations, or such longer period as may be agreed upon, either party may, by written notice to the other party, require that the parties be assisted in their negotiations by the Ontario Energy Board. In accordance with the OEB dispute resolution process, The Ontario Energy Board will complete its review of the dispute within 150 days.

SECTION 2 DISTRIBUTION ACTIVITIES (GENERAL)

2.1 Connections

This section includes information that is applicable to all customer classes of the distributor. Items that are applicable to only a specific customer class are covered in [Section 3](#).

2.1.1 Building that Lies Along

As provided in Section 28 of the [Electricity Act 1998](#) the Distributor has the Obligation to Connect any Building that ‘lies along’ its distribution system subject to conditions outlined in section 2.1.3.

A building ‘lies along’ a distribution line if it can be connected to the distributor distribution system without an expansion or enhancement.

A Building that appears to ‘lie along’ a distribution line may be refused connection to that line should the distribution line not have sufficient capacity for the requested connection. In such instances, the distributor shall make an offer to connect which will include the cost of the enhancement.

2.1.2 Offer to Connect

The Distributor will make an Offer to Connect to any customer requesting a connection within the Distributors licensed territory. As required by the Distribution Code, the Offer to Connect must be Fair and Reasonable and be based on the distributors’ design standard. The Offer to Connect must also be made within a reasonable time from the request for connection and the receipt of all required information from the Customer.

The Distributor may require a customer to pay all or a part of the costs of electrical plant installed to supply only that customer. Such capital contributions will be calculated using the guidelines set out by the OEB in the [Distribution System Code](#). If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached [Distribution Connection Process](#) for further information.

2.1.3 Connection Denial

The [Distribution System Code](#) in section 3.1 sets out the conditions for a Distributor to deny connections. A Distributor is not obligated to connect a building within its service territory if the connection would result in any of the following:

- Contravention of existing Canadian Laws, and those of the Province of Ontario.

- Violations of conditions in a Distributors' Licence.
- Use of a distribution system line for a purpose that it does not serve and that the Distributor does not intend to serve.
- Adverse effect on the reliability and safety of the distribution system.
- Imposition of an unsafe work situation beyond normal risks inherent in the operation of the distribution system.
- A material decrease in the efficiency of the distributors' distribution system.
- A material adverse effect on the quality of distribution services received by an existing connection.
- Discriminatory access to distribution services.
- Potential increases in monetary amounts that already are in arrears with the distributor

The distributor shall inform the person requesting the connection of the reason(s) for not connecting and, where the distributor is able to provide a remedy, make an offer to connect. If the distributor is unable to provide a remedy to resolve the issue, it is the responsibility of the customer to do so before a connection may be made.

2.1.4 Inspections Before Connections

The Distributor has the right to request an inspection prior to any connection.

All customer electrical installations shall be inspected and approved by the Electrical Safety Authority, referred to herein as the ESA.

The Distributor requires notification from the ESA of this approval prior to the connection of a customer's service.

Services that have been disconnected for a period of six months or longer shall also be inspected and approved by the ESA prior to reconnection.

Temporary services, for construction purposes, are approved by the ESA for a period of twelve months and must be re-inspected should the period of use exceed twelve months.

The Distributor reserves the right to inspect and approve Transformer rooms, Vaults and Pads prior to, during, and following the installation of equipment.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

Customer owned substations must be inspected by both the Electrical Safety Authority and the Distributor, prior to connection to the Distribution system.

Duct banks and road crossings shall be inspected and approved by the Distributor prior to the pouring of concrete and again before backfilling.

The Distributor reserves the right to inspect any underground trenches prior to backfilling.

The Distributor reserves the right to approve the installation and location of all submarine cable. All documentation and permits required for laying of submarine cable must be provided to the Distributor. The installation of submarine cable must meet the requirements of all governing legislation.

All work done on existing Distributor plant must be authorized by the Distributor and carried out in accordance with all applicable safety acts and regulations.

In accordance with the [Distribution System Code](#), if the Distributor refuses to connect a building in its service territory that lies along one of its distribution lines, the distributor shall inform the person requesting the connection of the reasons for not connecting, and where the distributor is able to provide a remedy, make an offer to connect. If the Distributor is unable to provide a remedy to resolve the issue, it is the responsibility of the customer to do so before a connection can be made.

2.1.5 Relocation of Plant

The Distributor will, where feasible, accommodate requests to relocate electrical plant such as poles and metal enclosed equipment.

The customer will be required to pay all of the costs incurred by the relocation.

Requests by civic authorities to relocate distribution facilities will be done so in accordance with the appropriate regulations. See [Public Service Works on Highways Act](#).

2.1.6 Easements

To maintain the reliability, integrity and efficiency of the distribution system, the Distributor has the right to have supply facilities on private property registered against title to the property. Easements are required whenever the Distributors' underground or overhead plant is to be located on private property or crosses over an adjacent private property to service a Customer.

The Customer shall acquire and grant in the distributors name, at no cost to the Distributor, where required, an easement to permit installation and maintenance of service. The width and extent of this easement shall be determined by the Distributor. The easement shall be granted prior to connection of the service.

The Owner shall furnish to the Distributor, free and clear of all encumbrances, sufficient easements to enable the servicing of all existing or proposed developments or subdivisions from plants located on the Owners' property.

Sufficient property at suitable locations shall be made available for the purpose of the installation of distributors' assets.

The Customer will prepare at its own costs a reference plan and associated easement documents to the satisfaction of the Distributors' solicitor prior to its registration and register the easement plan. Details will be provided upon application for service.

Where surface restoration by the Distributor is required following any repairs or maintenance to a service, the Distributor will in so far as is practicable, restore the property to its original condition; and provide compensation for any damages caused by the entry that cannot be repaired.

2.1.7 Contracts

Standard Form of Contract - All customers will be requested to complete and sign the standard form of contract to apply for a connection. A Standard Contract for service shall be considered as being in force from the date it is signed by the Customer and the Distributor and shall remain in force until terminated by either party.

Implied Contract - In all cases, notwithstanding the absence of a formal contract, the taking and using of electrical energy from the Distributor by any Person or Persons constitutes the acceptance of the terms and conditions of all regulations, conditions and rates as established by the Distributor. Such acceptance and use of energy shall be deemed to be the acceptance of a binding contract with the Distributor and the Person so accepting shall be liable for payment for such energy and the contract shall be binding upon the Person's heirs, administrators, executors, successors or assigns.

Special Contracts - Special contracts that are customized in accordance with the service requested by the Customer normally include, but are not necessarily limited to, the following examples:

- *construction sites*
- *mobile facilities*
- *non-permanent structures*
- *special occasions, etc.*
- *generation*

2.2 Disconnection

The Distributor has the right and/or obligation to disconnect the supply of electrical energy to a Customer for causes including but not limited to:

- (a) contravention of the laws of Canada or the Province of Ontario including the Ontario Electrical Safety Code;
- (b) violation of conditions in a distributor's licence;
- (c) materially adverse effect on the reliability or safety of the distribution system;
- (d) imposition of an unsafe worker situation beyond normal risks inherent in the operation of the distribution system;
- (e) a material decrease in the efficiency of the distributor's distribution system;

- (f) inability of the distributor to perform planned inspections and maintenance;
- (g) a materially adverse effect on the quality of distribution services received by an existing connection; and
- (h) if the person requesting the connection owes the distributor money for distribution services, or for non-payment of a security deposit.

2.3 Conveyance of Electricity

2.3.1 Guaranty of Supply

The Distributor agrees to use reasonable diligence in providing a regular and uninterrupted supply but does not guarantee a constant supply or the maintenance of unvaried frequency or voltage and will not be liable in damages to the Customer by reason of any failure in respect thereof.

Customers requiring a high degree of security of supply or power quality are responsible to provide their own back-up or standby facilities.

When power is interrupted, or the Customer is experiencing power quality problems the Customer or their electrical contractor shall first ensure that interruption is not due to problems within the customer owned installation. If after verifying that the cause of the problem does not reside on the customers' installation, the customer shall contact the Distributor. The Distributor will respond to and take reasonable steps to restore power. The Distributor reserves the right to recover costs from the customer for making false claims of interruptions.

Although it is the Distributors' policy to minimize inconvenience to Customers, it is necessary to occasionally interrupt a Customers' supply to maintain or improve the Distributors' system, or to provide new or upgraded services to other Customers. Whenever practical and cost effective, as determined by the Distributor, arrangements suitable to the Customer and the Distributor may be made to minimize any inconvenience. The Distributor will endeavor to provide the Customer with reasonable advance notice, except in cases of emergency, involving danger to life and limb, or impending severe equipment damage.

The Distributor will endeavor to notify Customers prior to interrupting the supply to any individual service. However, if an unsafe or hazardous condition is found to exist, or if the use of electricity by apparatus, appliances, or other equipment is found to be unsafe or damaging to the Distributor or the public, service may be discontinued without notice.

Depending on the outage duration and the number of Customers affected, the Distributor may issue a news release to advise the general public of the outage.

2.3.2 Power Quality

The distributor will respond to and take reasonable steps to investigate consumer power quality complaints and report to the consumer on the results of the investigation. The method and level of investigation will be at the discretion of the Distributor.

If the source of a power quality problem is caused by the consumer making the complaint, the distributor may seek reimbursement for the time and cost spent to investigate the complaint.

If the source of a power quality problem is caused by a consumer, the Distributor may direct the consumer to take corrective action. If the Consumer does not take such action within a reasonable time, the Distributor may disconnect the supply of power to the Customer. (see [section 2.2](#))

2.3.3 Electrical Disturbances

There are levels of voltage fluctuation and other disturbances that can cause flickering lights and more serious difficulties for Customers connected to the Distributor distribution system.

Some types of electronic equipment, such as video display terminals, can be affected by the close proximity of high electrical currents that may be present in transformer rooms.

No electrical equipment, which may produce an undesirable system disturbance, shall be connected by a customer to a customer's service without prior approval of the Distributor.

Examples of equipment, which may cause disturbance, are large motors, welders and variable speed drives. In planning the installation of such equipment, the customer is required to consult with the Distributor.

The Distributor will endeavour to maintain voltage variation limits, under normal operating conditions, at the Customers' Delivery Points, as specified by the latest edition of the [Canadian Standards Association, C235](#). However, more sensitive electronic equipment such as computers can be seriously affected by variations in quality of supply voltage. Customers who need electrical power of high quality and with rigid voltage tolerances are responsible for providing their own power conditioning equipment.

Customers requiring a three-phase supply should install protective apparatus to avoid damage to their equipment, which may be caused by the interruption of one phase, or non-simultaneous switching of phases of the Distributors' supply.

The customer shall provide such protective devices as may be necessary to protect his property or equipment from any disturbance beyond the control of the distributor.

2.3.4 Standard Voltage Offerings

2.3.4.1 For Secondary Voltage

The Supply Voltage governs the limit of supply capacity for any Customer. General guidelines for supply from overhead street circuits are as follows:

- *at 120/240 V. single phase, or*
- *347/600 V. three phase, four wire, or*
- *120/208 V three phase, four wire,*

OR

Where street circuits are buried, the Supply Voltage and limits will be determined upon application to the Distributor.

OR

Where the Customer or Developer provides a pad on private property;

- *at 120/240 V single phase, or*
- *at 120/208 V three phase, four wire, or*
- *at 347/600 V three-phase, four-wire*

2.3.4.2 For Primary Voltage

Primary supplies to transformers or customer-owned substations will be one of the following as determined by the Distributor:

- *2,400/4,160 volts 3 phase 4 wire*
- *4,800/8,320 volts 3 phase 4 wire*
- *7,200/12,400 volts 3 phase 4 wire*
- *8,000/13,800 volts 3 phase 4 wire*
- *16,000/27,600 volts 3 phase 4 wire*
- *27,600 volts 3 phase 3 wire delta*
- *44,000 volts 3 phase 3 wire*

The customer shall contact the Distributor when planning their service to verify standard transformer availability and supply capacity.

2.3.5 Voltage Guidelines

The Distributor maintains service voltage at the Customers' service entrance within the guidelines of C.S.A. Standard CAN3-C235 (latest edition) which allows variations from nominal voltage of: <http://www.csa-intl.org/onlinestore/GetCatalogDrillDown.asp?Parent=542>,

6% for Normal Operating Conditions

8% for Extreme Operating Conditions

Where voltages lie outside the indicated limits for Normal Operating Conditions but within the indicated limits for Extreme Operating Conditions, improvement or corrective action will be taken on a planned and programmed basis, but not necessarily on an emergency basis.

Where voltages lie outside the indicated limits for Extreme Operating Conditions, improvement or corrective action will be taken on an emergency basis. The urgency for such action will depend on many factors such as the location and nature of load or circuit involved, the extent to which limits are exceeded with respect to voltage levels and duration, etc.

2.3.6 Back-up Generators

Customers with portable or permanently connected emergency generation capability shall comply with all applicable criteria of the Ontario Electrical Safety Code and in particular, shall ensure that customer emergency generation does not back-feed on the Distributors' system.

To access the Code: http://www.esasafe.com/Corporate/gr_004.php?s=8

To review Generator Safety Info: http://www.esasafe.com/GeneralPublic/sgi_001.php?s=23

Customers with permanently connected emergency generation equipment shall notify the Distributor regarding the presence of such equipment.

The distributor reserves the right to have the connection of this equipment inspected.

Generation systems found to be feeding into the Distribution system without proper approval of the Distributor shall be subject to immediate disconnection.

2.3.7 Metering

2.3.7.1 General

2.3.7.1.1 Access

The Distributor or its agents shall have the right to access and read any of the Distributors' electricity



meters on the Customer's premises.

All metering installations shall be accessible from a public area.

2.3.7.1.2 Costs

All the Distributor metering equipment located on the Customer's premises are in the care and at the risk of the Customer and if destroyed or damaged, other than by normal usage, the Customer will pay for the cost of repair or replacement.

Regardless of any charges for metering installations, all meters and meter instrumentation equipment shall remain the property of the Distributor and maintenance of this equipment shall be the Distributors' responsibility.

2.3.7.1.3 Voltage

Generally, metering will be at utilization voltage. Where the Distributor provides primary transformation, primary voltage metering will be allowed only in special circumstances following full discussion with the Distributor.

Customer-owned substations may require primary metering. The provisions required for these installations shall be specified and approved by the Distributor for each application.

2.3.7.1.4 Primary Metering

Primary metering units may be installed outdoors or within an electrical vault as outlined in the current Electrical Safety Code. Where the customer prefers not to provide an approved electrical vault, the Distributor at additional cost can provide a metering unit with non-flammable coolant.

2.3.7.1.5 Bulk Metering

Non-residential or mixed-use buildings will normally be bulk metered by a single meter. However, where specific areas are clearly and permanently defined and in other respects as a separate entity, individual metering of the loads may be required.

Individual residential condominium or apartment units should be metered individually to empower the residents with control over their individual costs. In such instances, one or more bulk meters may still be required at the facility for the purpose of calculating house loads and/or transformer allowances (on customer owned transformers) where applicable.

In all installations where the Customer requests revenue metering remote from the secondary entrance equipment or downstream from a Customer-owned dry-core transformer, provisions are required for a bulk meter directly after the main switch. This bulk metering is required in addition to any public metering provisions. The Customer will be required to contribute to the cost of the metering installation.



Where more than one meter is required, the meters shall be grouped where practical.

The customer shall permanently and legibly identify all metered services with respect to correct municipal 911 address and unit #. The identification shall be applied to all service switches and breakers and to all meter cabinets and meter mounting devices that are not immediately adjacent to the service switch. The customer shall insure that all service identifications are accurate and by not doing so will be held responsible. The Distributor shall issue a Meter Verification Sheet for this purpose to the owner or contractor.

In any case, a copy of the metering layout plan shall be forwarded to the Distributor for review and approval.

If the distribution of the metered load circuit is in dispute, (ie: circuits from one premise is found to supply a second premise) the Distributor reserves the right to transfer all accounts into the Property Owners' name until such time as the problem has been resolved, and the individual metering can be clearly identified with the individual units.

2.3.7.1.6 Locks

All devices on the line side of the Distributor metering shall have provisions for padlocking.

For commercial and industrial services the Customer's main switch shall have provisions for padlocking the switch handle in the open position, and the switch cover (or door) in the closed position.

When a disconnect device has been locked in the "OFF" position by the Distributor, under no circumstances shall anyone other than the Distributor or its authorized agent remove the lock.

At the discretion of the Distributor, a dual locking arrangement, a Distributor master key arrangement, a key box arrangement, or a copy of the access key will be required for access.

2.3.7.1.7 Meter Seals

All devices used by the Distributor for metering are sealed. Only the Distributor or its authorized agents have the authority to break this seal. Tampering with the seal will require the Distributor to investigate the cause of the tampering. Following the investigation, the proper authorities will be contacted as required (*ESA, Police, Fire*). The customer shall be responsible for all reasonable costs associated with the investigation.

2.3.7.2 Current Transformer Boxes

Where a current transformer box is required, it shall be CSA approved, of a size and type as stipulated by the Distributor, and include a provision for padlocks. A removable plate shall be provided in the box for mounting the equipment.

As an alternative to a separate CT box and meter, a single enclosure combining both functions may be

feasible. Contact the Distributor for details.

In cases where the CTs only meter a portion of the metal clad switchgear (such as house loads), a separate disconnect switch must be installed ahead of the metering compartment so that the service can be de-energized without any interruption to the main service supply.

Generally, one house load meter only will be allowed. Additional house load meters will require authorization from the Distributor.

Conductors should enter the current transformer box at the top and leave at the bottom, or vice versa. If this cannot be arranged, the next largest CT box must be used to enable conductors to be trained in place. Where parallel conductors are used, the sum of the conductors will determine the size of the CT box to use. In all cases the Customer shall supply suitable cable termination lugs.

On all electrical services that require current transformers and the neutral for metering, an isolated neutral block shall be provided in the current transformer box.

2.3.7.3 Interval Metering

[The Distribution System Code](#), as amended from time to time, requires the Distributor to meter Customers of specific load levels with pulse-recording meters, or interval meters, which are interrogated remotely. The Distributor, at its' sole discretion, may also require such metering on any customer whose load characteristics may have a significant impact on the Net System Load Shape, or where reasonable access to the meter for the purpose of acquiring metering data may be limited due to location.

A customer that requests interval metering shall compensate a distributor for all incremental costs associated with that meter, including the capital cost of the interval meter, installation costs associated with the interval meter, ongoing maintenance (including allowance for meter failure), verification and re-verification of the meter, installation and ongoing provision of communication line or communication link with the customer's meter, and cost of metering made redundant by the customer requesting interval metering. The communication system utilized for interval meters shall be in accordance with the distributors' requirements.

Where such metering exists the Distributor will consider customer requests to provide a secondary pulse for load control or customer-owned metering at the customers' expense.

In keeping with the intent of the Legislation and accompanying amendments, once an interval meter installation is processed as part of the distributors' settlement process, and has affected the relevant changes to the distributors net system load, the installation must not be changed back to a non-interval meter installation.

Where a customer submits a request to read their own interval meter, the Distributor shall make this access available given the following conditions are met:

- The meter has the capability of read-only password protection
- The customer provides a signed copy of the “Interval Metering Access Agreement” to the Distributor.

2.3.7.3.1 Interval Metering Communications

- Solid-state recorders and/or Electronic Interval Meters installed by the Distributor have provision for remote interrogation. When a phone line is required for this purpose, the Owner will facilitate the provision of a telephone line in the metering cabinet for the Distributors’ metering purposes.
- At its’ sole discretion, for metering installations where loss of metering data would cause a substantial impact on the Distributors Settlement System and other customers, the Distributor may require the phone line to be dedicated for metering purposes only.
- When such dedicated phone lines are required, phone lines must be installed and functioning prior to the new service being energized
- A dedicated phone line is a voice quality telephone line, which is active 24 hours a day to the metering location extension jack, which is mounted on the metering board.

2.3.7.3.2 Smart Meters

The Ontario Government has mandated the installation of Smart Meters as a replacement to current metering technology. The LDC will install smart meters in accordance with regulations and policies set out by Government authorities.

Residential and small General Service customers, who are billed on an energy-only basis, will be provided with a smart meter free of charge during the smart meter conversion. Metering requirements for Large General Service customers will be reviewed in concert with any new Regulations.

2.3.7.4 Meter Reading

The Distributor will read all meters on a regularly scheduled basis whenever possible. If an actual meter reading is not obtained, the Customer shall pay a sum based on an estimated demand and/or energy for electricity used since the last meter reading.

2.3.7.5 Final Meter Reading

When a service is no longer required, or the Customer is switching Energy Providers, the Customer shall provide the Distributor sufficient notice of the date so that a final meter reading can be obtained. The Customer shall provide access to the Distributor or its agents for this purpose.

If a final meter reading is not obtained, the Customer shall pay a sum based on an estimated demand

and/or energy for electricity used since the last meter reading. Estimates will be based on available historical consumption.

2.3.7.6 Faulty Registration of Meters

Metering electricity usage for the purpose of billing is governed by the Federal Electricity and Gas Inspection Act and associated regulations, under the jurisdiction of Measurement Canada, Industry Canada. The Distributors' revenue meters are required to comply with the accuracy specifications established by the regulations under the above Act.

In the event of incorrect electricity usage registration, the Distributor will determine the correction factors based on the specific cause of the metering error and the Customer's electricity usage history. The Customer shall pay for all the energy supplied, a reasonable sum based on the reading of any meter formerly or subsequently installed on the premises by the Distributor, due regard being given to any change in the character of the installation and/or the demand.

If the incorrect measurement is due to reasons other than the accuracy of the meter, such as incorrect meter connection, incorrect connection of auxiliary metering equipment, or incorrect meter multiplier used in the bill calculation, the billing correction will apply for the duration of the error. The Distributor will correct the bills for that period in accordance with the regulations under the Act.

<http://www.collus.com/images/stories/Documents/Measurement Errors.pdf>

2.3.7.7 Meter Dispute Testing

The Distributor will attempt to resolve billing enquiries. However, to give Customers confidence in the accuracy of electricity meters, the Distributor will conduct an internal investigation to verify the accuracy of any meter the Customer believes to be recording incorrectly. If the internal investigation does not resolve the matter, the Customer or the Distributor may request Measurement Canada to test the meter.

<http://www.collus.com/images/stories/Documents/Measurement Errors.pdf>

If the test indicates that the meter is not accurate, the Customer's historic billing will be adjusted, and the Distributor shall pay the full costs of the meter dispute testing.

2.3.7.8 Location

The location of the indoor or outdoor meter shall be readily accessible at all times and acceptable to the Distributor. If a meter is recessed or enclosed after installation, without the prior approval of the Distributor, the service may be subject to disconnection.

The location of the service entrance, routing of duct banks, metering, and all other works will be established through consultation with the Distributor. Failure to comply may result in relocation of the service plant at the Owner's expense.

In all locations where Commercial/Industrial revenue metering is accessible to the general public, a lockable enclosure or a room for service equipment and meters, shall be provided by the Owner at the discretion of the Distributor, as follows:

- *An electrical room reserved solely for metering equipment or*
- *Metal enclosed switchgear approved by the Distributor or*
- *A suitable metal metering cabinet or*
- *A vandal proof cage.*

2.3.7.9 Meter Mounting Heights

Provision for metering shall facilitate a practical mounting height for revenue meters in compliance with the Distributor's standard specifications and all applicable codes and regulations.

2.3.7.10 Environment

The following requirements apply to the areas allocated for revenue metering.

The customer to the satisfaction of the Distributor shall provide where there is the possibility of danger to workmen, or damage to equipment from moving machinery, dust, fumes, or moisture, protective arrangements.

A clear safe working space of not less than 1.2 m (48") in front of the installation from the floor to ceiling with a minimum ceiling height of 2.1 m (84") provided to insure the safety of the Distributor or other authorized employee(s) who may be required to work on the installation.

Where excessive vibration may affect or damage metering equipment, adequate shock-absorbing mounting shall be provided and installed by the customer.

2.3.7.11 Meter Sockets

The owner will supply and install a meter socket as specified by the Distributor. Meter sockets will be directly accessible to the Distributors' staff.

A listing of approved revenue metering sockets is available from the Distributor.

2.3.7.12 Cabinets

Where required by these Conditions of Service the Owner shall supply and install a meter cabinet to The Distributors' requirements.

Meter cabinets shall be installed indoors, except where special permission is granted by the Distributor to install the meter cabinet outside. In such cases, an approved weather proof, lockable, C.S.A. approved meter cabinet shall be provided by the Customer.

2.3.7.13 Metering Loops

Three-phase, four-wire services will require a loop for metering, within the meter cabinet, for all three phases.

Mineral insulated, solid, or hard drawn wire conductors are not acceptable as metering loops.

2.3.7.14 Metal Enclosed Switchgear

The following regulations apply to the installation of instrument transformers and metering equipment within metal enclosed switchgear.

The Distributor will provide the following revenue metering equipment as required:

- Colour coded secondary wiring
- Revenue meters

The Owner shall:

- Consult with The Distributor regarding the installation of metering equipment, which may include:
 - Potential transformers
 - Potential transformer fuse holders and fuses
 - Current transformers
 - Phone line for remote interrogation of meters
 - Duplicate Pulse Initiators
 - Provide complete shipping instructions for instrument transformers for those projects where these are to be provided by the Distributor for installation by the switchboard manufacturer.
 - Install instrument transformers, metering cabinet and conduit.
 - Each main bus bar to be drilled and tapped (10-32) or (10-24) on the line side of the removable current transformer link.

- Submit two copies of the manufacturer's switchboard drawings, for approval, dimensioned to show provision for and arrangement of The Distributors' metering equipment.

Meters shall be installed by the Distributor in a customer-owned metal cabinet of a size and type pre-approved by the Distributor, mounted at an approved location separate from the switchgear.

Tamper proof or sealable rigid conduit or any equally approved conduit of a size and type specified by the Distributor shall be installed between the CT compartment of the switchgear and the meter cabinet.

For conduit installations greater than 30 m (100'), in length or where several bends are necessary, larger conduits or other special provision may be required, at the discretion of the Distributor.

2.3.7.15 Switchgear Connected to Wye Source

Where a Wye source neutral connection is to be used or grounded, the Owner shall provide a conductor sized to the requirements of the [Ontario Electrical Safety Code](#) from the instrument transformer compartment to the neutral connection.

2.3.7.16 Four Quadrant Metering (Generation)

All Ontario Energy Board-licensed generators connected to the distribution system that sell energy and settle through the distributor's retail settlement process shall be required to install metering that meets the requirements of the [Distribution System Code](#) as approved by the Ontario Energy Board, and/or the Market Rules as approved by the Independent Electricity System Operator. <http://www.theIESO.com/>

2.3.7.17 Net Metering for Embedded Generation

Customers with specific generation facilities may reduce their net energy costs by exporting surplus generated energy back onto the utility distribution system. Surplus energy exported onto the utility distributions system will be calculated as a credit against the energy the customer consumes from the distribution system.

All customers wishing to become a Net Metering participant must meet all of the following conditions:

1. The electricity is generated primarily for the customer's own use;
2. The electricity generated is conveyed to the customer's own consumption point without reliance on the utility's distribution system;
3. The maximum cumulative output capacity of the generator does not exceed 500 kW; and
4. The electricity is solely generated from a renewable energy source (such as wind, drop in water elevation, solar radiation, agricultural bio-mass, or any combination thereof).

In order to participate in the Net Metering program, the customer will be required to meet all the parallel generation requirements for Connecting Micro-Generation Facilities (10 kW or less) or Other Generation Facilities (greater than 10 kW and less than 500 kW), as applicable to the generator size, as found in Section 3.5 - Embedded Generation Facilities

The customer must have a bi-directional revenue meter that records energy flow in both directions.

2.3.7.18 Ontario Power Authority (OPA) Standard Offer Program for Embedded Generation

The Ontario Power Authority has established a Standard Offer Program (SOP) to encourage and promote greater use of renewable energy sources such as wind, solar, photovoltaic (PV), renewable biomass, biogas, bio-fuel, landfill gas, or drop in water elevation for generating electricity. Renewable energy electricity generation projects with a capacity of 10 MW or less that meets the program's requirements may be connected to the distribution system in order to export electricity.

Generating facilities participating in the Standard Offer Program will connect directly to the distribution system at a voltage of 44kV or less. Output from the generating facility shall be metered in a manner to ensure proper collection of required information for settlements. Such metering may include:

- a. for generators of 10 kW or less and connected to the line side of the load meter
 - (i) a bi-directional kWh meter to measure energy consumed and energy exported; or
 - (ii) a bi-directional interval meter to measure hourly energy consumed and energy exported
- b. for all other generators, an interval meter must be installed.

In some instances, the load meter may also have to be changed in order to accommodate proper settlement calculations for the SOP. The generator will be solely responsible for any costs associated with the connection to the distribution system and any required metering installation.

2.4 Tariffs and Charges

2.4.1 Service Connection

Charges for Service Connections are set out in the Distributors approved rates, (Miscellaneous Rates and Charges) and may be obtained by request from the Distributor. Notice of Rate revisions may be published in the local newspapers and or mailed out to all customers with the first billing issued at revised rates.

2.4.2 Energy Supply

The Distributor shall provide Customers connected to the Distribution System with access to electricity through Standard Supply Service as defined in the [Retail Settlement Code](#) published by the OEB or as

mandated through Legislation or Regulations issued by the Ministry of Energy.

Disputes arising from charges relating to Standard Supply Service shall be directed to the Distributor.

Customers will be switched to their Retailer of choice only if the retailer has a Service Agreement with the Distributor. The Customer's authorized Retailer through the Electronic Business Transaction system (EBT) must make the Service Transfer Request (STR) in accordance with the rules established and amended from time to time by the Ontario Energy Board.

Disputes arising from charges relating to Retailer Service shall be directed to the Retailer.

The Distributor may, at its discretion, refuse to process a Service Transfer Request for a Customer to switch to a Retailer if that Customer owes money to the Distributor for Distribution Services and or Standard Supply Service.

2.4.2.1 Wheeling of Power

Customers considering delivery of electricity through the Distributors' Distribution System shall contact the Distributor for technical requirements and current applicable Rates.

2.4.3 Supply Deposits & Agreements

Whenever required by the Distributor, the Customer shall provide and maintain security as specified in the Distribution System Code. The Distributor shall require security amounts based on the existing security and deposit policies.

Where a customer proposes the development of premises that requires the Distributor to place equipment orders for special projects, the customer is required to sign the necessary Supply Agreements and furnish a suitable deposit before such equipment is ordered by the Distributor. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached [Distribution Connection Process](#) for further information.

2.4.4 Billing

The Distributor may, at its option, render bills to its Customers on either a monthly, bi-monthly, quarterly or annual basis. The option applicable to the customer shall be identified to the customer at the time of application for service.

Prorating of Service and Demand charges will be performed at the discretion of the Distributor.

2.4.4.1 Competitive Charges:

Are based on rates as determined by:

- i. the Hourly Ontario Spot Market Price (HOEP); or
- ii. the utilities Weighted Average Price (WAP) as determined by net system load; or
- iii. the customers retailer contract rate; or
- iv. the rates published by the OEB; or
- v. Legislation or Regulations issued by the Ministry of Energy.

2.4.4.2 Non-competitive Charges:

Non-competitive Charges are based on rates approved by the Ontario Energy Board, and fall outside the scope of this document as they are adjusted on an annual basis. Approved rates as they relate to the transmission, distribution and other non-competitive elements may be attained through the utilities rate documents. These documents will be provided by the utility at the customer's request.

2.4.4.3 Billable Engineering Units:

Customers will be billed on:

- i. actual or estimated meter reading data; or
- ii. derived consumption data (Streetlights, sentinel lights and other scattered loads); or
- iii. a flat rate, depending on the type of load being billed.

2.4.4.4 Use of Estimates:

In months where a bill is issued, but no reading is obtained, the Distributor estimates usage in order to determine billing quantities. The estimate is based on historical usage for the premise, or a pre-determined quantity if there is no historical usage information available.

2.4.5 Payments and Late Payment Charges

Bills are rendered for distribution services and electrical energy used by the Customer. Bills are payable in full by the due date.

Bills are due when rendered by the utility. A customer may pay the bill without the application of a late payment charge up to a due date, which shall be a minimum of sixteen calendar days from the date of mailing or hand delivery of the bill. This due date shall be identified clearly on the customer's bill.

Where payment is made by mail, payment will be deemed to be made on the date post-marked. Where payment is made at a financial institution acceptable to the utility, payment will be deemed to be made when stamped/acknowledged by the financial institution or an equivalent transaction record is made.

A partial payment will be applied to any outstanding arrears before being applied to the current billing, unless special considerations have been made by the utility.

Outstanding bills are subject to the collection process and may ultimately lead to the service being discontinued or limited. Service will be restored once satisfactory payment has been made. Discontinuance of service does not relieve the Customer of the liability for arrears.

The Distributor shall not be liable for any damage on the Customer's premises resulting from such discontinuance of service. A reconnection charge may apply where the service has been disconnected due to non-payment.

The Customer will be required to pay additional charges for the processing of non-sufficient fund (N.S.F.) cheques.

2.4.6 Unauthorized Energy Use

The Distributor shall use its discretion in taking action to mitigate unauthorized energy use. Upon identification of possible unauthorized energy use, the Distributor shall notify, if appropriate, Measurement Canada, The Electrical Safety Authority, Police Officials, Retailers that service customers affected by an authorized energy use, or other entities.

The Distributor may recover from the parties responsible for the unauthorized energy use all costs incurred by the Distributor arising from unauthorized energy use, including an estimate of the energy used, inspection and repair costs.

A service disconnected due to unauthorized use of energy shall not be reconnected until such time as all arrears resulting from the unauthorized use has been resolved to the satisfaction of the Distributor.

Prior to reconnection, the Distributor shall require proper authorization from applicable authorities.

2.5 Customer Information

The Distributor reserves the right to request specific information from the customer in order to facilitate the normal operation of its business. Failure of a customer to supply such information may prevent the normal continuation of service.

The [Retail Settlement Code](#) as amended from time to time specifies the rights of customers and their retailers to access current and historical usage information and related data and the obligations of distributors in providing access to such information.

Under these requirements, the Distributor shall upon authorization by a customer make the following information available to the Customer or the Retailer that provides electricity to a customer connected to the Distributors' distribution system:

- The Distributors' account number for the customer,
- The Distributors' meter number for the meter or meters located at the customer's service address
- The customer's service address,
- The date of the most recent meter reading,
- The date of the previous meter reading,
- Multiplied kilowatt-hours recorded at the time of the most recent meter reading,
- Multiplied kilowatt-hours recorded at the time of the previous meter reading,
- Multiplied kW for the billing period (if demand metered),
- Multiplied kVA for the billing period (if available),
- Usage (kWh's) for each hour during the billing period for interval-metered customers
- An indicator of the read type (e.g., distributor read, consumer read, distributor estimate, etc.)
- Average distribution loss factor for the billing period

This information will be provided to the Customer / Retailer upon request twice per year at no charge. The Distributor may request a fee to recover costs for additional requests. A request is considered to be data delivered to a single address. Thus, a single request to send information to three locations is considered three requests.

The Distributor acknowledges that no confidential information regarding its' customers shall be released to a third party without the expressed prior written consent of the customer unless the request is rightfully received from the third party requesting the information, or the Distributor is legally required to disclose such information under the terms and in accordance with the Freedom of Information and Protection of Privacy Act, R.S.O. 1990, c. F.31.

HOTLINK <http://www.collus.com/images/stories/Documents/Measurement Errors.pdf>

SECTION 3 CUSTOMER SPECIFIC

3.1 Residential

This section refers to the supply of electrical energy to Customers residing in residential dwelling units.

3.1.1 General

Energy is generally supplied as single phase, 3-wire, 60-Hertz, having a nominal voltage of 120/240 Volts.

There shall be only one [Delivery Point](#) to a dwelling.

In circumstances where two existing services are installed to a dwelling, and one service is to be upgraded, the upgraded service will replace both of the existing services.

All new single-family homes will be required to install their primary and secondary service wires to the specifications contained within the Distributors' technical specification document.

Whether the method of supply will be overhead or underground will be at the discretion of the distributor. The Distributor will adhere to any existing regulations subject to requirements of authorities.

Unless specifically documented otherwise to the Customer, where the distributor has taken ownership of such plant all services installed by the Distributor or by an approved contractor using approved materials, will be maintained by the Distributor.

3.1.2 Early Consultation

The Customer shall supply a completed [Site Planning document](#) and related information to the Distributor well in advance of installation commencement. (see appendix) The information shall be supplied in a manner requested by the Distributor at the time of the application.

3.1.3 Standard Connection Allowance

For the purposes of calculating customer connection fees, the Basic Connection for Residential consumers is defined as 100 amp 120/240 volt overhead service.

The basic connection for each customer shall include;

- i. supply and installation of overhead distribution transformation capacity or an equivalent credit for transformation equipment; and
- ii. up to 30 meters of overhead conductor or an equivalent credit for underground services.

In the case of an upgrade to an existing service, where the existing service is below the basic connection, the credit up to the basic connection will apply.

Secondary services exceeding the basic 30 meter length may require specific design approved by the Distributor to ensure power quality.

3.1.4 Variable Connection Fees

Any requirements above the defined basic connection shall be subject to a variable connection charge to be calculated as the costs associated with the installation of connection assets above and beyond the basic connection. The distributor may recover this amount from a customer through a connection charge or equivalent payment.

3.1.5 Point of Demarcation

In all cases the final [Demarcation Point](#) will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Secondary Service owned by the Distributor includes repair and like-for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

3.1.5.1 Secondary Service Connections

The Point of Demarcation for residential services up to and including 400 amps is at the line side of the Meter Base for Underground services, and at the top of the stack for Overhead services, beyond which the customer bears full responsibility for installation and maintenance.

The Point of Demarcation for residential services over 400 amps is at the secondary side of the transformer.

For Secondary Services wholly owned and maintained by the Customer, the [Demarcation Point](#) is the secondary connection at the transformer or the service bus.

The Customer shall install, own, and maintain the secondary conductor under any of the following conditions:

- (a) conductor terminations are inside the Customer's building;
- (b) conductor is installed beyond the service entrance;
- (c) conductor is connected to a Primary Service; or
- (d) conductor is a non-standard installation.

3.1.5.2 Primary Service Connections

For Primary Service, the [Demarcation Point](#) is the primary connection at the Distributor's Distribution system.

3.1.6 Supply Voltage

- (a) A Residential building is supplied at one service voltage per land parcel.
- (b) Depending upon the location of the building the supply voltage will be one of the following:
 - o 120/240 Volts 1 Phase 3 Wire
 - o 120/208 Volts 1 Phase 3 Wire
 - o 120/208 Volts 3 Phase 4 Wire
 - o 347/600 Volts 3 Phase 4 Wire
- (c) The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.1.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

3.1.8 Metering:

The owner will supply and install a meter socket complete with collar acceptable to the Distributor. Meter sockets will be directly accessible to the Local Distribution Company and:

- Mounted 1.7 meters from the finished grade to the center of the meter and, either on the exterior of the front of the building or, within 3 meters of the front of the building on the driveway side.
- Installed ahead of (on the line side of) the main disconnect switch.
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact the Distributor for specific location instructions prior to installation.

For more details refer to section [2.3.7](#) in these Conditions of Service.

3.1.9 Overhead Service

The Owner will provide service equipment to both the Distributors' and ESA requirements, and be of sufficient height to maintain proper minimum clearances. The Owner's main switch and the overhead service conductors will be of compatible capacity.

3.1.10 Underground Service

Underground secondary services will be installed at the Owners' expense, to the Distributor's specifications. The Owner's main switch and the underground service conductors will be of compatible capacity.

3.1.11 Street Townhouses and Condominiums:

NOTE: Street Townhouses and Condominiums requiring centralized or bulk metering will be covered under section [3.2](#) of these Conditions of Service. Also [3.1.11.2](#)

3.1.11.1 Service Information:

The Owner will enter into a Servicing Agreement with the Distributor, governing the terms and conditions under which the electrical distribution system and services will be designed and installed.

The Owner will provide all of the civil works to accommodate the Distributor and will pay the complete cost of the electrical distribution system, design and services.

- The distribution system and services shall be underground unless otherwise approved.
- One service will be provided for each unit.
- The nominal service voltage will be 120/240 volts, 1 phase, 3 wire.
- The Distributor will approve the location of duct banks, service routings and meter bases.

- Distribution plant shall not be installed until grade is at +/- 150 mm of final grade unless otherwise approved by the Distributor.
- Street lighting will be to Municipal standards and installed at the Owner's expense.

3.1.11.2 Metering:

The Owner will supply and install meter sockets specified by the Distributor.

Multiple or grouped meter bases will be accepted only when prior approval has been given by the Distributor both as to type and proposed location. A completed meter verification form shall be provided to the distributor prior to energization.

Meter sockets will be located on the exterior front wall of the units and will be directly accessible to the Distributor.

- Mounted on the front wall 1.7 metres above finished grade to the centre of the meter
- Installed ahead of (on the line side of) the main disconnect switch
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact the Distributor for specific location instructions prior to installation.

Normally the service will not be energized until the outside finish in the area of the revenue meter has been completed. If exceptions are made to this, then the general contractor will be responsible for ensuring that the meter is suitably protected while work is being done on the exterior wall adjacent to the meter. The general contractor will be entirely responsible for all costs for materials and labour for repairing or replacing a damaged meter. Meters must always remain fully accessible for reading, replacement, repair, and general maintenance. Customers and/or their contractors should contact the Distributor prior to enclosing meters and/or meter bases to ensure that safety and access are not compromised or the Distributor may disconnect the service until remedial action, as determined by the Distributor, are undertaken

3.1.12 Seasonal and Remote Dwellings:

Due to the varied nature of Seasonal and Remote Dwellings some special arrangements may be required to service these locations. Arrangements will be made in such a manner to provide services such as restoring power, maintenance of equipment or new construction requests to water access or remote customers, without endangering personnel or the public.

3.1.12.1 Service Information:

The Owner will enter into a Servicing Agreement with the Distributor, governing the terms and conditions under which the electrical distribution system services will be provided.

In the event of a power interruption, the Distributor will respond to and take reasonable steps to restore power. The Distributor reserves the right to recover costs from the customer for making false claims of interruptions.

3.1.12.2 Access:

All operations performed by the distributor and its agents shall be performed within the rules and regulations set out by the appropriate authorities including but not limited to: ESA, Ministry of Labour, Ministry of Transportation, etc.

- **Night crossings**

The Distributors' transportation equipment will not be used to cross any water ½ hour before sunset and ½ hour after sunrise due to safety concerns. It will be at the discretion of the Distributor whether they will board customer owned transportation equipment in these circumstances.

- **Ice conditions**

Recognizing seasonal ice hazards, the Distributor reserves the right to suspend water passage during freeze up and spring thaw, as well as any such time deemed unsafe by the Distributor.

- **Severe weather conditions**

Recognizing that severe weather conditions may pose undue safety hazards, the Distributor reserves the right to postpone attempts to restore power until restoration can be performed in a safe manner.

3.1.13 Inspection:

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.



The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

(Refer to section [2.1.4](#) for further inspection details)

3.2 General Service (Below 50 kW)

3.2.1 General

This section refers to the supply of electrical energy to General Service Buildings requiring a connection with a connected load less than 50 kW, and, Town Houses and Condominiums described in section [3.1.8](#) that require centralized bulk metering.

General Service buildings are defined as buildings that are used for purposes other than single-family dwellings.

3.2.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with the Distributor in the early planning stages to ascertain the Distributors' requirements.

The Owner shall supply a completed [Electrical Planning Requirements Form](#) to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment etc.

3.2.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Below 50 kW) shall be recovered through a variable connection Fee.

3.2.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a variable connection charge. The distributor may recover this amount from a customer through a connection charge or equivalent payment. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached [Distribution Connection Process](#) for further information.

3.2.5 Point of Demarcation

In all cases the final [Demarcation Point](#) will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be

relocated at the Customer's expense.

Maintenance of the portion of the Secondary Service owned by the Distributor includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

3.2.5.1 Secondary Service Demarcations

A General Service Customer [Demarcation Point](#) is at the secondary side of the transformer, or as otherwise set by the distributor, beyond which the customer bears full responsibility for installation and maintenance.

In some instances, where it is in the best interest of the operation of the distribution system, the Distributor may establish the Demarcation Point at the top of stack for overhead services or at the meter base for underground services.

The Demarcation Point might be located on an adjacent property. In such cases, a registered easement must exist.

3.2.5.2 Primary Service Demarcations

For Primary Service, the Demarcation Point is the primary connection at the Distributor's Distribution system.

3.2.6 Supply Voltage

- (a) A General Service building is supplied at one service voltage per land parcel.
- (b) Depending upon the location of the building the supply voltage will be one of the following:
 - o 120/240 Volts 1 Phase 3 Wire
 - o 120/208 Volts 1 Phase 3 Wire
 - o 120/208 Volts 3 Phase 4 Wire
 - o 347/600 Volts 3 Phase 4 Wire

- (c) The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.2.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission" from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

3.2.8 Metering:

The owner will supply and install a meter socket complete with collar acceptable to the Distributor. Meter sockets will be directly accessible to the Distributor and unless otherwise specified during the early consultation process:

- Mounted 1.7 metres from the finished grade to the center of the meter and, either on the exterior of the front of the building or, within 3 metres of the front of the building on the driveway side.
- Installed ahead of (on the line side of) the main disconnect switch.
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact the Distributor for specific location instructions prior to installation.

For more details refer to section [2.3.7](#) in these Conditions of Service.

3.2.9 Overhead Service:

In circumstances where Commercial buildings cannot reasonably be supplied electrical energy by an underground service, the Distributor shall use its' sole discretion based on acceptable industry practices in establishing the specific requirements for the service installation.

3.2.10 Underground Service:

Under normal circumstances, Commercial buildings are supplied electrical energy by an underground service through a single point of entry for each land parcel, at a location specified by the Distributor.

3.2.11 Supply of Equipment:

The Distributor supplies, installs and maintains subject to the variable connection fee:

- Primary switchgear.
- Primary transformation equipment.
- Meter and secondary metering transformers.

The Owner shall supply, install and maintain any additional equipment required for the connection beyond the point of Demarcation.

3.2.12 Inspection:

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

(Refer to section [2.1.4](#) for further inspection details)

3.3 General Service (Above 50 kW)

3.3.1 General

This section refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load greater than 50 kW.

3.3.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with the Distributor in the early planning stages to ascertain the Distributors' requirements.

The Owner shall supply a completed [Electrical Planning Requirements Form](#) to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment etc.

3.3.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Above 50 kW) shall be recovered through a variable connection Fee.

3.3.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a "variable connection charge". The distributor may recover this amount from a customer through a connection charge or equivalent payment. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached [Distribution Connection Process](#) for further information.

3.3.5 Point of Demarcation

In all cases the final [Demarcation Point](#) will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Secondary Service owned by the Distributor includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all

civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

3.3.5.1 Secondary Service Connections

A General Service Customer Demarcation Point for customers above 50 kW is at the secondary side of the transformer, or as otherwise set by the distributor, beyond which the customer bears full responsibility for installation and maintenance.

In some instances, where it is in the best interest of the operation of the distribution system, the Distributor may establish the Delivery point at the top of stack for overhead services or at the meter base for underground services.

The location of the service entrance, routing of duct banks and all other works will be established through consultation with the Distributor. Failure to comply may result in relocation of the service plant at the Owner's expense.

The Demarcation Point might be located on an adjacent property. In such cases, a registered easement must exist.

3.3.5.2 Primary Service Connections

For Primary Service, the [Demarcation Point](#) is the primary connection at the Distributor's Distribution system.

In some circumstances the owner may be required to construct a private pole line. Primary conductors will be terminated complete with cut-out(s) at the Demarcation Point by the Distributor at the owners' expense.

Where a private pole line is to be constructed by the Owner with an approved contractor, this shall be constructed to the ESA and the Distributors' requirements.

An electrical requirement in excess of 300 kVA may require a customer owned substation.

In some instances primary metering may be required.



3.3.6 Supply Voltage

A General Service building is supplied at one service voltage per land parcel. Depending upon the location of the building the supply voltage will be one of the following:

- 120/240 Volts 1 Phase 3 Wire
- 120/208 Volts 3 Phase 4 Wire
- 347/600 Volts 3 Phase 4 Wire

Depending upon the location of the building Primary supplies to transformers and Customer owned Sub-Stations will be one of the following as determined by the Distributor:

- 2,400/4,160 volts 3 phase 4 wire
- 4,800/8,320 volts 3 phase 4 wire
- 7,200/12,400 volts 3 phase 4 wire
- 8,000/13,800 volts 3 phase 4 wire
- 16,000/27,600 volts 3 phase 4 wire
- 44,000 Volts - 3 Phase 3 Wire

The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.3.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission" from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

3.3.8 Metering:

Meter installations will be directly accessible to the Distributor. The owner will consult with the Distributor well in advance of installation commencement to allow the Distributor time for proper planning and ordering of equipment.

For more details refer to section [2.3.7](#) in these Conditions of Service.

3.3.9 Overhead Service:

In circumstances where Commercial buildings cannot reasonably be supplied electrical energy by an underground service, the Distributor shall use its' sole discretion based on acceptable industry practices in establishing the specific requirements for the service installation.

3.3.10 Underground Service:

Under normal circumstances, Commercial buildings are supplied electrical energy by an underground service through a single point of entry for each land parcel, at a location specified by the Distributor.

3.3.11 Sub-transmission Service:

The Owner will pay for the full cost of sub-transmission services and may in some circumstances be required to construct a private pole line. The Distributor will terminate sub-transmission conductors complete with live line loops and hardware at the Demarcation Point.

3.3.12 Supply of Equipment:

The Distributor supplies, installs and maintains subject to the variable connection fee:

- Primary switchgear.
- Primary transformation equipment.
- Meter and secondary metering transformers.

The Owner shall supply, install and maintain any additional equipment required for the connection beyond the point of Demarcation.

3.3.13 Short Circuit Capacity:

The Owner shall ensure that the service entrance equipment has an adequate short-circuit interrupting capability.

3.3.14 Inspection:

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.



The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

(Refer to section [2.1.4](#) for further inspection details)

3.4 General Service (Above 500 kW)

3.4.1 General

This section refers to the supply of electrical energy to General Service Services requiring a connection at a connected load greater than 500 kW.

3.4.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with the Distributor in the early planning stages to ascertain the Distributors' requirements.

The Customer shall supply a completed [Electrical Planning Requirements Form](#) to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment, and coordination with ESA requirements etc.

Note: Larger services may require approval by the ESA to ensure compliance with their design requirements. The customer should contact the ESA early in the planning stages.

The Distributor will:

- *Advise the customer of the suitability of the in-service date*
- *Arrange with the customer for a Service Contract*
- *Review the submitted drawings; return one set to the customer with comments and/or approval. If requested by the Distributor, the customer shall resubmit the drawings where the comments are extensive and require major changes*
- *Specify the required main fuse link or relay setting for co-ordination with the system. In case of multiple transformer stations, a complete co-ordination study shall be submitted by the customer for approval.*
- *Make the final connection to the source of supply*
- *Determine metering requirements*
- *Advise the Transmitter of the particulars of the customer owned substation*

3.4.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Above 500 kW) shall be recovered through a variable connection Fee.

3.4.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a variable connection charge. The distributor may recover this amount from a customer through a connection charge or equivalent payment. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached [Distribution Connection Process](#) for further information.

3.4.5 Point of Demarcation

In all cases the final [Demarcation Point](#) will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Primary Service owned by the Distributor includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

The Distributor reserves the right to direct the operations of any customer owned switchgear connected to the distribution system including those located beyond the point of demarcation.

3.4.5.1 Service Installation

In General, the [Demarcation Point](#) for a General Service Customer with a demand of over 500 kW is on the primary side of the transformer at the first available distributor owned point of isolation, or as otherwise set by the distributor. This delivery point might be located on an adjacent property from which the Distributor has an authorized easement. In all cases the final Demarcation Point will be the decision of the Distributor.

The location of the service entrance, routing of duct banks, metering facilities, and all other works will be established through consultation with the Distributor. Failure to comply may result in relocation of the service plant at the Owner's expense.

The Distributor will install overhead supply lines and required cut-outs to the first point of support on private property. The location of this support must be approved by the Distributor and shall be within 30 metres of the Distributors' existing overhead plant. All costs for materials and labour shall be at the customers' expense.

The service pole or first point of support on private property shall be considered self-supported and shall be complete with suitable hardware for attaching the suspension insulators. The Customer shall be responsible for all costs associated with equipment, installation, and inspection.

Where the customer wishes an underground supply, the customer shall supply and install the underground cables and termination pole complete with primary switch, fuses and lightning arresters. The installation shall be subject to ESA inspection and specific approval of the Distributor. The customer owned termination pole must comply with items as prescribed by the Distributor.

At the Distributors' discretion, the customers' underground service may be connected to a termination pole owned by the distributor. In such cases, the Distributor shall supply and install at the customers expense, any required primary switch, fuses, and lightning arresters.

When requested, the customer shall make provision in the substation switchgear or transformer, for loop feeding the Distributors' supply cables via load interrupter switches.

In some instances, primary metering may be required.

3.4.6 Supply Voltage

A General Service building is supplied at one service voltage per land parcel.

General Service connections above 500 kW may require a customer owned substation.

Depending upon the location of the building, Primary supplies to transformers and Customer owned Sub-Stations will be one of the following as determined by the Distributor:

- *2,400/4,160 volts 3 phase 4 wire*
- *4,800/8,320 volts 3 phase 4 wire*
- *7,200/12,400 volts 3 phase 4 wire*
- *8,000/13,800 volts 3 phase 4 wire*
- *16,000/27,600 volts 3 phase 4 wire*
- *44,000 Volts - 3 Phase 3 Wire*

The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.4.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission" from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

Where the high voltage interrupting switches are located inside a building, a direct outside entrance to the switchgear room must be provided.

The outside door providing direct access to the transformer or switchgear room must be compliant with all applicable codes and requirements, and of a quality to be approved by the Distributor.

3.4.8 Metering:

The owner will supply and install provisions for metering following the details outlined both in these Conditions of Service, and technical documents provided to the customer during the consultation process.

For more details refer to section [2.3.7](#) in these Conditions of Service.

3.4.9 Sub-transmission Service:

The Owner will pay for the full cost of sub-transmission services and may in some circumstances be required to construct a private pole line.

The Distributor will terminate sub-transmission conductors complete with live line loops and hardware at the [Demarcation Point](#).

3.4.10 Short Circuit Capacity:

The Owner shall ensure that the service entrance equipment has an adequate short-circuit interrupting capability.

3.4.11 Drawings

Apart from the regular drawings submission to the ESA, the customer shall provide two sets of the following drawings and details to the Distributor.

Survey Plan: prepared by an Ontario Land Surveyor, showing the property limits, registered plan and existing buildings or easements if any.

Site Plan: showing the location of the station relative to buildings, structures and set backs from adjacent property lines. The site plan shall also include the exact location of existing Distributor owned plant and the proposed route of the incoming supply.

Schematic or Single-Line Diagram: indicating the major components of the station and their electrical ratings. Where additions or alterations are being made, these shall be clearly distinguished from unchanged portions of the installation.

Electrical Details: sufficient details shall be provided in order to enable fast processing and approval of the station drawings. The following represents the minimum data required.

- Plan, elevation and profile views of the station structure, switchgear, transformer(s), termination poles, duct banks, etc.
- Dimensions to clearly indicate the electrical, physical and working clearances as well as relative location of all equipment.
- Pole or structure for dead-ending the Distributor lines shall be complete with suitable hardware for attaching the suspension insulators that will be supplied and installed by the Distributor.
- Fencing arrangement.
- Grounding details. (In the case of indoor metal enclosed switchgear, when the Distributor has operating control of any interrupter switches, the assembly shall further incorporate ground rod parking stands and stirrups per the Distributors Specifications.)
- Details of vault construction (if indoor substation).
- Manufacturer's drawings of metal-enclosed switchgear showing internal arrangement of equipment, clearances, means of access, interlocking and provision for personal safety. Where the Distributors' cables terminate in the switchgear, the customer shall provide suitable terminators for the size and type of cable as specified by the Distributor.
- When the customer's switchgear is used for loop feeding the Distributors' supply cables, provision for padlocking the in and out load interrupter switches and the associated bay doors shall be required.
- Indoor and outdoor switchgear assemblies shall contain a space heater and protective guard in each bay, along with thermostat(s), sized to promote air circulation and to prevent condensation from forming.

- At the discretion of the distributor, the customer shall make provisions for a future system neutral connection to the customer's dead-ending pole or structures installed by the Distributor. Where the Distributors' neutral terminates in the customer's switchgear, the customer shall provide a suitable connector on the ground bus for the size and type of cable specified by the Distributor.

3.4.12 Pre-Service Inspection

The customer shall present to the Distributor a final "Pre-service Inspection Report" a minimum of 3 working days before connection can be affected.

The "Pre-Service Inspection Report" shall outline and document the results of all tests and inspection carried out on the substation components. The information contained in the report must be to the satisfaction of the Distributor before connection can be authorized.

The "Pre-Service Inspection Report" shall be required in case of:

- **New Substation:** *in which case all components of the substation shall be reported upon.*
- **Modified substation:** *in which case all components of the substation shall be reported upon.*

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

(Refer to section [2.1.4](#) for further inspection details)

3.5 Embedded Generation

3.5.1 General

An Embedded Generator shall provide the Distributor with proof of compliance of [IESO](#) or [OEB](#) registration Requirements, and appropriate Licences.

The Distributor shall collect costs reasonably incurred with making an offer to connect a generator from the entity requesting the connection. Costs reasonably incurred include costs associated with:

- Preliminary review for connection requirements.
- Detailed study to determine connection requirements.
- Final proposal to the generator.

A Generator that is or wishes to become connected to the distributors' distribution system shall enter into a Connection Agreement with the Distributor.

If damage or increased operating costs result from a connection with a Generator, the Generator shall reimburse the Distributor for these costs.

The Embedded Generator is responsible for providing suitable embedded generator equipment to protect his plant and equipment for any conditions on the distributor and interconnected transmission systems such as reclosing, faults and voltage unbalance.

To incorporate the connection of embedded generator to the distribution system, the line/feeder protection including settings and breaker reclosing circuits must be reviewed and modified if necessary by the distributor or transmission authority. This process may be complex and may require significant time.

The embedded generator must submit a proposed single line diagram and protection scheme for review to the distributor contact as identified by the distributor.

Based on the transformer connection proposed by the embedded generator additional significant protection cost may be incurred (e.g. delta HV transformer winding may require 3 phase HV breaker / reclosure device). The embedded generator shall not order the protection equipment and transformer until the station line diagram is reviewed and accepted by the distributor.

The purpose of the distributor review is to establish that the embedded generator electrical interface design meets the distributor requirements.

The protection schemes shall incorporate adequate facilities for testing/maintenance.

Negative phase sequence protection shall be installed where required, to detect abnormal system condition as well as to protect the generator.

The embedded generator may be required to install utility grade relays for those protections that could affect the distributor or transmission authority system.

The embedded generator may be required to submit a Ground Potential Rise study for review by the distributor, if telecommunications circuits are specified for remote transfer trip protection.

3.5.2 Protection

The embedded generator should provide protection systems to cover the following conditions:

3.5.2.1 Internal Faults:

The Generator should provide adequate protections to detect and isolate generator and station faults.

3.5.2.2 External Faults:

The protection system should be designed to provide full feeder coverage complete with a reliable DC supply. In some cases redundancy in protection schemes may be required.

Normally the following fault detection devices are required for synchronous generator(s) installation(s).

3.5.2.3 Ground Faults:

When the HV winding of the Generator station transformer is wye connected with the neutral solidly grounded, then ground over-current protection in the neutral is required to detect ground faults.

If the Embedded generator station transformer HV winding connected to the Distributor system is ungrounded wye or delta, then ground under-voltage and ground over-voltage protections shall be required to detect ground faults.

Depending on the size, type of generator and point of connection, a distributor may require the relaying system to be duplicated, complete with separate auxiliary trip relays and separately fused DC supplies to ensure reliable protection operation and successful isolation of the embedded generator.

3.5.2.4 Phase Faults:

To detect phase faults, at least one of the following protections should be installed with acceptable redundancy where required depending on fault values:

- Distance
- Phase directional over-current
- Voltage-restrained over-current
- Over-current
- Under-voltage

3.5.2.5 Islanding/Abnormal Conditions:

Voltage and frequency protections are required to separate the embedded generator from the distribution system for an islanded condition and thus maintain the quality of supply to distribution system customers. This also will enable speedy restoration of the distribution system.

Typically, the protections required to detect islanding/abnormal conditions are:

- Over-voltage
- Under-voltage
- Over-frequency
- Under-frequency
- Voltage-balance

The above protections should be timed to allow them to ride through minor disturbances.

3.5.3 Induction Generator

Due to the operating characteristics of the induction generator the protection package required is normally less complex than the synchronous generator. An embedded generator should design the protection scheme to trip for the same conditions as stated for synchronous generators. An induction generator is an asynchronous machine that requires an external source such as a healthy distribution system to produce normal 60 Hz power. Alternatively, if there is an outage in the distribution system then there is unlikely to be 60 Hz output from the induction generator. In certain instances, an induction generator may continue to generate electric power after the source is removed. This phenomenon, known as self-excitation, can occur whenever there is sufficient capacitance in parallel with the induction generator to provide the necessary excitation and when the connected load has certain resistive characteristics.

3.5.4 DC Remote Tripping / Transfer Tripping

Remote or transfer tripping may be required between the Generator and the feeder circuit breaker if the Generator is connected at a critical location in the distribution system. This feature will provide for isolation of the embedded generator when certain faults or system disturbances are detected at the feeder circuit breaker location.

Additional Protection Features, such as Remote Trip and Generator end open signal, may be required in some applications. Remote Trip Protection will often involve the participation of a neighboring or Host LDC. Early consultation is important to ensure a timely connection to the system.

3.5.5 Maintenance

An Embedded Generator shall have a regular scheduled maintenance plan to assure the Distributor that all connection devices and protection & control systems are maintained in good working order. These provisions shall be included in the Connection Agreement. A complete copy of the inspection report shall be delivered to the Distributor within 30 days.

In developing a maintenance plan, the Generator should consider the following requirements:

- Qualified personnel should carry out all inspections and repairs.
- Periodic tests should be performed on protection systems to verify that the system operates as designed. Testing intervals for protection systems should not exceed four (4) years for microprocessor-based systems and two (2) years for electro-mechanical based systems.
- Isolating devices at the point of connection should be operated at least once per year.
- The Generator facility should be inspected visually at least once per year to note obvious maintenance problems such as broken insulators or other damaged equipment.
- Any deficiencies identified during inspections shall be noted and repairs scheduled as soon as possible, with timing dependent on the severity of the problem, due diligence concerns (of both the Distributor and the Generator) and financial and material requirements. The Distributor shall be notified of any deficiencies involving critical protective equipment.
- The Distributor shall be provided with copies of all relevant inspection and repair reports that may affect the protection and performance of the Distributors' systems. The Distributor has the right to witness any relevant test being performed by the generator.

3.6 Embedded Market Participant

An Embedded Market Participant shall provide the Distributor with proof of compliance of [IESO](#) registration Requirements, and appropriate Licences.

Where the Conditions of Service of this Distributor exceed the technical requirements of any other licence or participant obligations, these Conditions of Service shall take precedence.

The Embedded Market Participant must meet at a minimum, the standards as set out in these Conditions of Service in order to connect to the Distributors' distribution facilities.



3.7 Embedded Distributor

An Embedded Distributor shall provide the Distributor with proof of compliance of [IESO](#) and [OEB](#) registration Requirements, and appropriate Licences.

Where the Conditions of Service of this Distributor exceed the technical requirements of any other licence or participant obligations, these Conditions of Service shall take precedence.

The Embedded Distributor must meet at a minimum, the standards as set out in these Conditions of Service in order to connect to the Distributors' distribution facilities.

Metering requirements of the Embedded Distributor shall be at the discretion of the Host Distributor.

3.8 Miscellaneous Small Services

This section pertains to the supply of electrical energy for Street Lighting, Traffic Signals, Bus Shelters, Telephone Booths, Cable T.V. Amplifiers, Decorative Street Lighting, Bill Boards, and other similar small loads.

3.8.1 General

At the discretion of the Distributor, the service voltage will be:

120/240 volts, single phase three wire or
120 volts, single phase two wire or
347/600V three phase, four wire

The method and location of the supply will vary based on the conditions present on the Distributors' plant, and will be established for each application through consultation with the Distributor.

Where specified by the Distributor during the Early Consultation process, the Customer will provide underground ducts to the Distributor's specifications.

The Owner shall be responsible for all costs associated with the supply and installation of service conductors

The Distributor at the Owners' expense will install required transformation.

Where at the discretion of the Distributor, a meter is not installed, energy consumption will be based on the connected wattage and the calculated hours of use.

Prior to energization of a service the Distributor will require notification from the [ESA](#) that the installation has been inspected and approved for connection.

3.8.2 Early Consultation

The Owner shall supply a completed [Electrical Planning Requirements Form](#) to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment etc. Information required includes:

- Required in-service date
- Requested Service Entrance Capacity and voltage rating of the service entrance equipment
- Locations of other services, gas, telephone, water and cable TV
- Survey plan and site plan indicating the proposed location of the service equipment with respect to public rights-of way and lot lines.

3.8.3 Street Lighting

Town street-lighting that is designed, installed, and maintained by the Distributor shall be fully funded by the Municipality to ensure adherence to the [Affiliate Relationship Code](#) and the Distributors' Licence.

3.8.4 Traffic Signals

Traffic Signals and Crosswalk Lights are owned and maintained by the applicable road authority.

3.8.5 Bus Shelters

Bus Shelter Lighting is owned and maintained by the Customer.

3.8.6 Decorative Street Lighting

Such installations could be lighting for festive occasions or "neighbourhood character" street-scaping and will be maintained by the Customer.

SECTION 4 GLOSSARY OF TERMS

“Conditions of Service” means the document developed by the distributor in accordance with subsection 2.3 of the [Distribution System Code](#), that describes the operating practices and connection rules for the distributor;

“Condominiums” are located on common land, which is the property of a condominium corporation or is owned by the Owner of all of the units (rental property). These units usually front onto internal roads that are also privately owned;

“Condominium Development” is a structure or complex of structures each containing more than two residential units. A single residential customer would occupy each unit and have direct outside access at ground level;

“Connection” means the process of installing and activating connection assets in order to distribute electricity;

“Connection Agreement” means an agreement entered into between a distributor and a person connected to its distribution system that delineates the conditions of the connection and delivery of electricity to or from that connection;

“Connection assets” means that portion of the distribution system used to connect a customer to the existing main distribution system, and consists of the assets between the point of connection on a distributors’ main distribution system and the ownership Demarcation Point with that customer;

“Consumer” means a person who uses, for the person’s own consumption, electricity that the person did not generate;

“Customer” means a person that has contracted for or intends to contract for connection of a building or an embedded generation facility. This includes developers of residential or commercial subdivisions;

“Demand meter” means a meter that measures a consumers’ peak usage during a specified period of time;

“Demarcation Point” means the point at which the obligation of the Distributor ends and those of the Customer begin for the purposes of maintenance and repair of the distribution service;

“Disconnection” means a deactivation of connection assets, which results in cessation of distribution services to a consumer;

“Distribute”, with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less;

“Distribution losses” means energy losses that result from the interaction of intrinsic characteristics of the distribution network such as electrical resistance with network voltages and current flows;

“Distribution loss factor” means a factor(s) by which metered loads must be multiplied such that when summed equal the total measured load at the supply point(s) to the distribution system.;

“Distribution services” means services related to the distribution of electricity and the services the Board has required distributors to carry out.

“Distribution system / plant” means a system for distributing electricity, and includes any structures, equipment or other things used for that purpose. A distribution system is comprised of the main system capable of distributing electricity to many customers and the connection assets used to connect a customer to the main distribution system;

“Distribution System Code,” means the code, approved by the Board, and in effect at the relevant time, which, among other things, establishes the obligations of a 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;

“Distributor” means a person who owns or operates a distribution system;

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

“Energy Competition Act” means the *Energy Competition Act, 1998*, S.O. 1998, c. 15;

“Electrical Safety Authority” or **“ESA”** means the person or body designated under the *Electricity Act* regulations as the Electrical Safety Authority;

“Embedded Distributor” means a distributor who is not a wholesale market participant and that is provided electricity by a host distributor;

“Embedded Generation Facility” means a generator whose generation facility is not directly connected to the IESO-controlled grid but instead is connected to a distribution system;

“Embedded Load Displacement Generation Facility” means an embedded generation facility connected to the customer side of the revenue meter where the generation facility does not inject electricity into the distribution system for the purpose of sale;

“Embedded Market Participant” means a consumer who is a wholesale market participant whose facility is not directly connected to the IESO-controlled grid but is connected to a distribution system;

“Emergency” means any abnormal system condition that requires remedial action to prevent or limit loss of a distribution system or supply of electricity, or that could adversely affect the reliability of the electricity system;

“Emergency backup generation facility” means a generation facility that has a transfer switch that isolates it from a distribution system;

“Enhancement” means a modification to an existing distribution system that is made for purposes of improving system operating characteristics such as reliability or power quality or for relieving system capacity constraints resulting, for example, from general load growth;

“Expansion” means an addition to a distribution system in response to a request for additional customer connections that otherwise could not be made; for example, by increasing the length of the distribution system;

“Four-quadrant Interval Meter” means an interval meter that records power injected into a distribution system and the amount of electricity consumed by the customer;

“Generate”, with respect to electricity, means to produce electricity or provide ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system;

“Generation Facility” means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system, and includes any structures, equipment or other things used for that purpose;

“Generator” means a person who owns or operates a generation facility;

“Geographic Distributor” with respect to a load transfer, means the distributor that is licensed to service a load transfer customer and is responsible for connecting and billing the load transfer customer;

“Good Utility Practice” means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America;

“Holiday” means a Saturday, Sunday, statutory holiday, or any day as defined in the Province of Ontario as a legal holiday;

“IESO” means the Independent Electricity System Operator established under the Electricity Act;

“IESO-Controlled Grid” means the transmission systems with respect to which, pursuant to agreements, the IESO has authority to direct operation;

“Interval meter” means a meter that measures and records electricity use on an hourly or sub-hourly basis;

“Large Embedded Generation Facility” means an embedded generation facility with a name-plate rated capacity of 10MW or more;

“Lies Along” means a property can be connected to the distributor distribution system without an expansion or enhancement, and meets the conditions listed in the Conditions of Service of the distributor who owns or operates the distribution line.

“Load Transfer” means a network supply point of one distributor that is supplied through the distribution network of another distributor and where this supply point is not considered a wholesale supply or bulk sale point;

“Load Transfer Customer” means a customer that is provided distribution services through a load transfer;

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

“Measurement Canada” means the Special Operating Agency established in August 1996 by the *Electricity and Gas Inspection Act*, 1980-81-82-83, c. 87., and *Electricity and Gas Inspection Regulations* (SOR/86-131);

“Medium Sized Embedded Generation Facility” means an embedded generation facility with a name-plate rated capacity of less than 10 MW and:

- a) more than 500 kW in the case of a facility connected to a less than 15kV line;
- b) more than 1 MW in the case of a facility connected to a 15 kV or greater line;

“Meter Service Provider” means any entity that performs metering services on behalf of a distributor, generator, or registered market participant;

“Meter Installation” means the meter and, if so equipped, the instrument transformers, wiring, test links, fuses, lamps, loss of potential alarms, meters, data recorders, telecommunication equipment and spin-off data facilities installed to measure power past a meter point, provide remote access to the metered data and monitor the condition of the installed equipment;

“Metering Services” means installation, testing, reading and maintenance of meters;

“Micro Embedded Load Displacement Generation Facility” means an embedded load displacement generation facility with a name-plate rated capacity of 10 kW or less;

“Net Metering” means a settlement process for Embedded Generation behind a Load Customer meter as defined by Ontario Regulation 541/05

“Ontario Electrical Safety Code” means the code adopted by O. Reg. 164/99 as the Electrical Safety Code;

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

“Operational Demarcation Point” means the physical location at which a distributors’ responsibility for operational control of distribution equipment including connection assets ends at the customer;

“Ownership Demarcation Point” means the physical location at which a distributors’ ownership of distribution equipment including connection assets ends at the customer;

“Physical Distributor” with respect to a load transfer, means the distributor that provides physical delivery of electricity to a load transfer customer, but is not responsible for connecting and billing the load transfer customer directly;

“Point of Supply” with respect to an embedded generation facility, means the connection point where electricity produced by the generation facility is injected into a distribution system;

“Rate” means any rate, charge or other consideration, and includes a penalty for late payment;

“Rate Handbook” means the document approved by the Board that outlines the regulatory mechanisms that will be applied in the setting of distributor rates;

“Regulations” means the regulations made under the *Act or the Electricity Act*;

“Retail”, with respect to electricity means,

- a) To sell or offer to sell electricity to a consumer
- b) To act as agent or broker for a retailer with respect to the sale or offering for sale of electricity,
or
- c) To act or offer to act as an agent or broker for a consumer with respect to the sale or offering for sale of electricity.

“Retail Settlement Code” means the code approved by the Board and in effect at the relevant time, which, among other things, establishes a distributors’ obligations and responsibilities associated with financial settlement among retailers and customers and provides for tracking and facilitating customer transfers among competitive retailers;

“Retailer” means a person who retails electricity;

“Service Area” with respect to a distributor, means the area in which the distributor is authorized by its license to distribute electricity;

“Small Embedded Generation Facility” means an embedded generation facility which is not a micro-embedded generation facility with a name-plate rated capacity of 500 kW or less in the case of a

facility connected to a less than 15 kV line and 1MW or less in the case of a facility connected to a 15 kV or greater line;

“Smart Meter” means a device that measures electrical energy use (kilowatt-hours, kWh) on an hourly or sub-hourly basis and is part of an integrated data management system. The meter records, stores and transmits date and time-stamped meter readings to a utility’s computer to facilitate Time-of-Use and Hourly billing. Smart meters may also include other capabilities and features to aid in load management and energy conservation.

“Standard Offer” means a settlement process for distribution connected Embedded Generation under contract for supply with the Ontario Power Authority.

“Total losses” means the sum of distribution losses and unaccounted for energy;

“Townhouses” are usually a free hold property, the land is owned by the individual Owners of each unit, fronting onto a municipal street;

“Townhouse Development” is a structure or complex of structures each containing more than two residential units. A single residential customer would occupy each unit, and have direct outside access at ground level;

“Transmission System” means a system for transmitting electricity, and includes any structures, equipment or other things used for that purpose;

“Transmission System Code” means the Board approved code that is in force at the relevant time, which regulates the financial and information obligations of the Transmitter with respect to its relationship with customers, as well as establishing the standards for connection of customers to, and expansion of a transmission system;

“Transmit” with respect to electricity, means to convey electricity at voltages of more than 50 kilovolts;

“Transmitter” means a person who owns or operates a transmission system;

“Unaccounted-for Energy” means all energy losses that cannot be attributed to distribution losses. These include measurement error, errors in estimates of distribution losses and un-metered loads, energy theft and non-attributable billing errors;

“Un-metered loads” means electricity consumption that is not metered and is billed based on estimated usage;

“Validating, Estimating and Editing (VEE)” means the process used to validate, estimate and edit raw metering data to produce final metering data or to replicate missing metering data for settlement purposes;



“Wholesale Market Participant” means a person that sells or purchases electricity or ancillary services through the IESO-administered markets;



SECTION 5 APPENDICIES

[Contact Information](#)

[Distribution Connection Process](#)

[Request For Connection Form](#)

[Electrical Planning Requirements Document](#)

[Electric Service Meter Base/ Service Verification Form](#)

Contact Information

Local Distribution Company	Contact Phone Number	
Centre Wellington Hydro Ltd.		730 Gartshore Street, Box 217 Fergus, Ont. N1M 2W8
Licence # ED-2002-0498	Phone: (519) 843-2900	
COLLUS Power Corp.		Box 189, 43 Stewart Road Collingwood, Ont. L9Y 3Z5
Licence # ED-2002-0518	Phone: (705) 445-1800	
Grand Valley Energy Inc.		P.O. Box 400 - 400 C Line Orangeville, Ont. L9W 2Z7
Licence # ED-2002-0512	Phone: (519) 928-3112	
Hydro 2000 Inc.		265 St. Philippe Street P.O.Box 370 Alfred, Ont. K0B 1A0
Licence # ED-2002-0542	Phone: (613) 679-4093	
Innisfil Hydro Distribution Systems Limited.		2073 Commerce Park Drive Innisfil, Ont. L9S 4A2
Licence # ED-2002-0520	Phone: (705) 431-4321	
Lakefront Utilities Inc.		207 Division St. P.O. Box 577 Cobourg, Ont. K9A 4L3
Licence # ED-2002-0545	Phone: (905) 372-2193	
Lakeland Power Distribution Ltd.		5-45 Cairns Cres. Huntsville, Ont. P1H 2M2
Licence # ED-2002-0540	Phone: (705) 789-5442	
Midland Power Utility Corporation		16984 Highway #12 Midland, Ont. L4R 4P4
Licence # ED-2002-0541	Phone: (705) 526-9361	
Orangeville Hydro Ltd.		P.O. Box 400 - 400 C Line Orangeville, Ont. L9W 2Z7
Licence # ED-2002-0500	Phone: (519) 942-8000	
Orillia Power Distribution Corporation		360 West St. South, P.O. Box 398 Orillia, Ont. L3V 6J9
Licence # ED-2002-0530	Phone: (705) 326-2495	
Parry Sound Power Corporation		125 William Street Parry Sound, Ont. P2A 1V9
Licence # ED-2003-0006	Phone: (705) 746-5866	
Rideau St. Lawrence Distribution Inc.		985 Industrial Rd. P.O. Box 699 Prescott, Ont. K0E 1T0
Licence # ED-2003-0003	Phone: (613) 925-3851	
Wasaga Distribution Inc.		950 River Road West P.O. Box 20 Wasaga Beach, Ont. L0L 2P0
Licence # ED-2002-0544	Phone: (705) 429-2517	
Wellington North Power Inc.		290 Queen Street West, P.O. Box 359 Mount Forest, Ont. N0G 2L0
Licence # ED-2002-0511	Phone: (519) 323-1710	
Westario Power Inc.		24 Eastridge Road R.R. #2 Walkerton, Ont. N0G 2V0
Licence # ED-2002-0515	Phone: (519) 507-6937 Toll Free: 1-866-978-2746	
West Coast Huron Energy Inc.		64 West Street Goderich, Ont. N7A 2K4
Licence # ED-2002-0510	Phone: (519) 524-7371	
Woodstock Hydro Services Inc.		16 Graham Street P.O. Box 1598 Woodstock, Ont. N4S 0A8
Licence # ED-2003-0011	Phone: (519) 537-3488	

Note: Licence Numbers published by OEB as of May 8, 2008



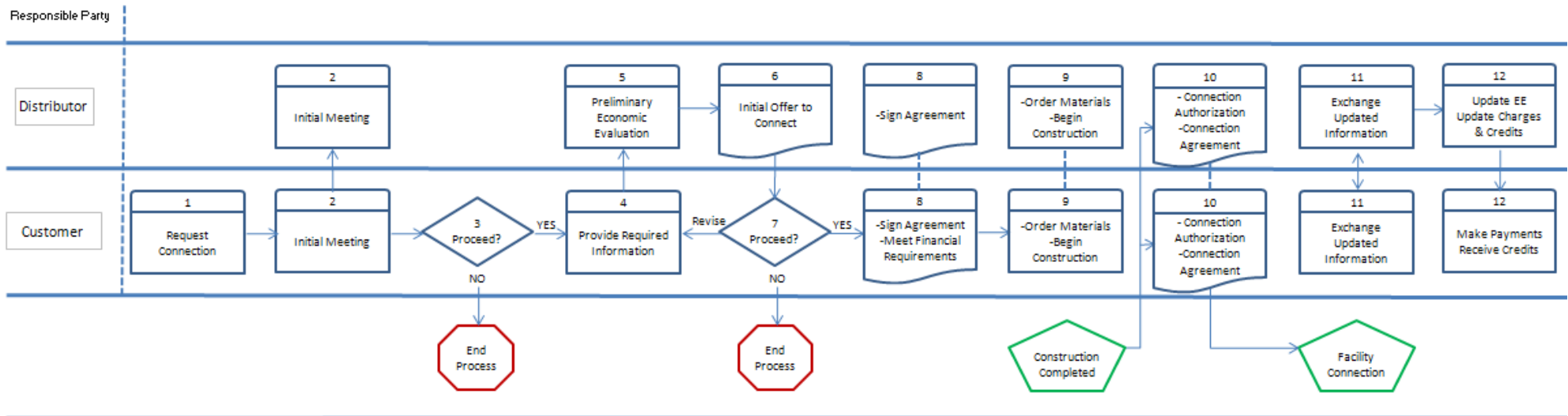
Cornerstone Hydro Electric Concepts Association Inc.



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Distribution Connection

Distribution Connection Developments & General Service Customers



Distribution Connection Developments & General Service Customers

If you are planning on building a Subdivision, Commercial Building, or an Industrial Development, the process of connecting to the Local Distribution Infrastructure will require coordination with the Distributor.

The following information in conjunction with the preceding chart is designed to assist the parties in meeting their respective obligations and facilitate the required connection. It is important to note although the steps identified in both the chart and the following descriptions need to be followed in proper order, some of the steps may be combined to help speed up the process if all the required information is provided in a timely manner.

Step 1 – Request for Connection

Customer submits a connection request to the Distributor. Initial request should at a minimum include the following information:

- Location of proposed development
- General description of development
- Proposed construction date
- Contact information for Development

Step 2 – Initial Meeting

Customer and Distributor meet to review proposed new development and connection requirements. Initial meeting will provide both parties with an opportunity to gain a better understanding of the proposed development and identify any issues related to timing and connection to the Distribution System.

Based on the information provided by the customer prior to the meeting, the Distributor will be able to provide at a high level:

- An initial concept of the type of work that may be required to facilitate a connection. ie:
 - o Extension of an existing Feeder
 - o Potential requirement for a new DS
 - o Add a second or third phase to an existing feeder
- An understanding of the of the customer responsibilities
- An understanding of what must be managed by the Distributor
- An understanding of what may be contracted by the customer
- An estimated timeline required to provide connection facilities
- An initial estimate of required enhancement or expansion costs – note: more detailed estimates on costs will be provided with the Offer to Connect should the Customer choose to continue to Step 4.

Step 3 – Customer Decision

Based on the results of the initial meeting, the Customer decides on proceeding with the process or withdrawing their Request for Connection.

Step 4 – Customer Provides Required Information

If the Customer decides to proceed with the process for acquiring a connection, the Customer notifies the Distributor and provides the relevant detailed information as noted below:

- A statement noting if the Customer intends on managing the contestable work noted during the consultation
- Number of Residential Connections
- Residential – Type, Number, and size of units
- Number of Commercial / Industrial Connections
- Estimated Average Monthly consumption (at minimum winter & summer estimates)
- Estimated annual facility connections over five years from date of LDC system connection

The following information is also required however the Distributor reserves the right to perform the work internally or through an external consultant:

- Design and engineering specifications including but not limited to stamped site service drawings
- Determination of required Transformation based on estimated building loads
- Estimated Capital costs of facilities which would be assumed by the Distributor following energization

To assist the Customer in providing the required information, a submission summary sheet is provided as an attachment to this document.

Step 5 – Preliminary Economic Evaluation

Upon receipt of the required information from the Customer, if an expansion of the distribution system is required, the Distributor will perform a preliminary Economic Evaluation following the process as required in the Distribution System Code.

The Preliminary Economic Evaluation will assist the Distributor in calculating what (if any) portion of the Capital Costs the LDC will invest and will be used in the preparation of the Offer to Connect.

Step 6 – Offer to Connect

Using the information provided by the Customer, and following the completion of the Preliminary Economic Evaluation, the Distributor will prepare an “Offer to Connect”. The Offer to Connect will contain the following information:

- A statement as to whether the offer is a firm offer or an estimate to be revised after the actual costs are known
- The amount of Capital Contribution that will be required from the Customer
- The amount of the Expansion Deposit that will be required from the Customer
- A description of the costs related to the Capital Contribution
- The costs for inspections
- A description of the deliverables required from the Customer before Connection
- An estimated Connection Date

Step 7 – Customer Decision

Customer Reviews Offer to Connect and decides if they would like to continue with the project as planned. Three options are available to the Customer:

- Customer elects to drop the project a notice of withdrawal of the Request for Connection shall be provided to the Distributor.
- Customer would like to revise their Connection request, a notice informing the Distributor of the requested changes shall be provided to the Distributor (go back to Step 4)
- Customer agrees with the Offer to Connect,

Step 8 – Construction Agreement

Once the Customer accepts the Distributor's Offer to Connect, the parties shall enter into an agreement covering the construction and connection requirements and responsibilities. The Customer and the Distributor sign the agreement and the Customer provides the financial deposits and/or guarantees as required.

Step 9 – Construction

Following receipt of signed Construction Agreement and required financial deposits and/or guarantees from the Customer, both parties shall begin ordering materials and begin construction.

Step 10 – Connection Authorization

Once construction is completed, both parties will ensure that inspections are completed and all required connection authorizations are in place. After receipt of a signed connection agreement and any additional financial contributions, the Distributor will authorize and connect the facility. If the customer is coordinating the work on the expansion facilities within the development, the customer is also required to provide "As-Built" drawings and a detailed material listing to ensure the Distributor has sufficient information in hand to verify system security prior to energization.

Step 11 – Exchange Updated Information

The Customer and the Distributor shall exchange any required updated information on the project including, but not limited to:

- All applicable Connection Authorizations
- All applicable Warranties
- Any new information that was provided as an estimate in Step 4
- Actual costs of any "capital works" related to the expansion facilities within the development
- Detailed site plan with appropriate Municipal Address information for individual services

Step 12 –Updated Economic Evaluation

As required, the Distributor shall recalculate the Preliminary Economic Evaluation using actual information acquired during and following the construction process.

If the development includes estimated connections that are not energized at the time of the initial Connection, the Distributor shall re-run the Economic Evaluation on an annual basis using actual customer connection information during the five (5) year connection horizon used in the initial Economic Evaluation.



Request for Connection

Development Name:
Site Plan Identification

Contact Information:

Contact Name:
Street:
Town:
Postal Code:

Requested Connection Date:

Multi-Phase Development?
If YES - Identify Phase

Y / N

Type & Number of Connections:

Residential:
Commercial:
Industrial:

Average Monthly Consumption
Per Unit -
Winter

Kwh's
Kwh's
Kwh's

Per Unit - Summer

Kwh's
Kwh's
Kwh's

Residential Dwelling Design:

Town Homes
Semi-Detached
< 1,500 SqFt Single Dwellings
>1,500 <3,500 SqFt Single Dwellings
> 3,500 SqFt Single Dwellings

Connection Horizon

Year 1

Year 2 Estimated connections in 1st year

Year 3 Estimated connections in 2nd year

Year 4 Estimated connections in 3rd year

Year 5 Estimated connections in 4th year

Estimated connections in 5th year

Capital Costs:

Distribution Infrastructure:
Transformers:
Ducts & Structures:

Date: Submitted:
Submitted By:
Signature:

**Electrical Planning Requirements**

It is essential that the following information be provided to:

- a) enable an assessment to be made on the impact of the proposed project on the Electrical Distribution System.
- b) enable the Distributor to prepare pertinent information for the developer.

Please supply answers to the following questions as soon as possible as electrical planning cannot proceed until the Distributor has reviewed this information.

Preliminary electrical site plan drawings are to be submitted together with this form. Electrical drawings are to be submitted to the Distributor for approval prior to any related job tenders or the commencement of any electrical construction. The drawings shall be drawn to a scale usable by the Distributor, shall show local pole locations, proposed transformer location, proposed electrical room/metering location and show how access to the metering would be gained (i.e.: the path to the metering).

Electrical site plan drawings are to be submitted to the Distributor on one (1) Paper copy and in an electronic format as approved by the Distributor.

Project Location: (Municipal Address)

Name of Project: _____

Name of Applicant: _____

Address: _____

Contact Name: _____

Address: _____

E-Mail: _____

Telephone: () _____

Fax: () _____

Service Classification (☒ as many as apply):

- ☐ Residential
- ☐ General Service < 50kW
- ☐ General Service > 50kW
- ☐ General Service >500kW
- ☐ Unmetered os Miscellaneous Load
- ☐ Temporary Service

What service voltage is required (☒ one only):

- ☐ 120/240 Volt Single Phase
- ☐ 120/208 Volt Three Phase
- ☐ 347/600 Volt Three Phase
- ☐ Primary

Required In-Service Date:

Month / Day / Year ____/____/____

**Service Entrance Switchboard with Utility
CT and PT Compartment**

☐ Yes ☐ No

Capacity of Main Service (in Amperes):

Maximum rated capacity: _____

Estimated Connected Load - Demand in kW:

Maximum initial Demand: _____ kW

Maximum Future Demand: _____ kW

Metering Type (☒ one only):

- ☐ Single Meter
- ☐ Multiple Meters

Quantity of Meter installations

100A or less: _____

101A to 200A: _____

more than 200A: _____

Comments: Please use the back of this form for comments

Signed: _____

(Representative of Applicant)

Name: _____

Date: _____

Title: _____



Electric Service Meter Base With Municipal Address Verification Form

LOCAL DISTRIBUTION COMPANY NAME: (UTILITY)

This form must be completed by a Licensed Electrical Contractor or their legal representative prior to service connection. Accurate information must be provided or service will not be activated. (Sections A & B must be fully completed.)

Electric Service Municipal Address: (Print)

Name of Owner:

Telephone: () Fax: ()

Name of Electrical Contractor:

Telephone: () Fax: ()

In area (A) provided below, a 'front-view' layout of the Electric Meter Base(s) is shown including an assigned number for each base. Provide Municipal Address (B) information for each corresponding meter base number for billing purposes.

(A) FRONT VIEW OF ELECTRIC METER BASE(S)	(B) MUNICIPAL ADDRESS (Print)
	1)
	2)
	3)
	4)
	5)
	6)
	7)
	8)

The following regulations are agreed upon by the undersigned with receipt of the completed form by an authorized representative of the Utility: (A copy of the utility authorized form will be provided for your records.)

1. That all information contained on this form is accurate.
2. That if any information is determined to be inaccurate, the Utility will not be able to energize the service connection(s).
3. That if any information has to be corrected by Utility personnel there will be applicable charges to prepare an amended form.
4. That an amended form must be signed and returned along with payment of any applicable invoice, as per Part 3, prior to further consideration as to the activation of the service connection.
5. The Electrical Contractor completes Section (C) below to apply for service activation. A property owner MAY complete Section (D) rather than the contractor, to apply for service activation.

(C) The undersigned acknowledges agreement to all terms and conditions contained on this form.
(Please print names in full)

Company Name:

Representative:

Title/Position: Date: (m / d / y)

Signature

(D) OPTIONAL if section (C) has been completed. The undersigned acknowledges agreement to all terms and conditions contained on this form.

Owner Name: (Please print)

Signature: Date: (m / d / y)

For COLLUS Power office use only:

Received : Date / / Approved: (Rep's Signature)

(Authorized Rep's Name) (m / d / y)

(Address) (Telephone #)



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Changes in Conditions of Services

A revised version of the conditions of service was filled with the OEB on August 1, 2008. As at the date of this application, WPI does not plan to make any changes to its Conditions of Service.

Service Quality Indicator

WPI reports annually its service quality and service reliability metrics; that is, its service quality indicators. WPI did not meet the minimum standards for all service quality indicators in 2005, and 2006.

		2005	2006	2007
Connection of New Services – Low Voltage	90% or better	88.58	90.04	96.90
Connection of New Services – High Voltage	90% or better	N/A	100.0	N/A
Underground Cable Locates	90% or better	92.43	93.11	97.0
Appointments met	90% or better	N/A	N/A	100.0
Telephone Accessibility	65% or better	97.20	87.97	93.20
Written Response to Inquiries	80% or better	94.77	90.48	100.0
Emergency Response – Urban	80% or better	76.42	91.22	92.10
Emergency Response - Rural	80% or better	N/A	N/A	N/A
SAIDI (System Average Interruption Duration Index)	Within the range of performance over the previous 3 years	0.38	0.87	0.30
SAIFI (System Average Interruption Frequency Index)	Within the range of performance over the previous 3 years	0.006	0.52	0.92
CAIDI (Customer Average Interruption Duration Index)	Within the range of performance over the previous 3 years	55.82	1.67	0.33

WPI tracks reliability metrics throughout the year and uses the system performance information to direct maintenance activities as input into the development of the Asset Management Plan's programs.

1. Connection of low voltage services - 2005 - 88.58% met vs. 90% expectation level.

In 2005 the metric was nearly met, having been missed by 7 service connections and the metric has been met in 2006, and 2007. Westario Power achieved this by reorganizing our workforce and dedicating two Service Crews to manage customer connections. The LV Connections SQI in 2006 and 2007 both show upward improvements.

2. Appointments Met - 2005 and 2006, information not available.

As of January 2007, a directive was provided to staff to record the time of appointment on the work order, and for the field staff to record the time of arrival on the work order. This directive will satisfy the SQI (going forward) by recording the timeliness of the appointment. To determine if the SQI was met, the arrival time would be compared to the appointment time.

1 **3. Emergency Response (Urban) - 2005 - 76.42% vs. 90% Expectation Level**

2 In late 2005 WPI revised its on-call practice and assigned two linemen to be on-call at all times.
3 Previous to this, the practice was to have one lineman on-call. The Emergency Response SQI
4 in 2006 and 2007 both showed upward improvements.

6 **4. SAIDI is the length of outage customers experience in the year on average**

7 On average, during 2006 customers are not without power for more than 53 minutes in the year.
8 In October Westario experienced several severe lightning and winds storms. In June and again
9 in July Westario experience equipment failure that lead to long outages. In one case a lightning
10 strike on a feeder interrupted power to an entire town, in another case; the upstream LDC
11 experienced a loss of supply interrupting power to another town for a prolonged period. If these
12 items are removed, the index is 0.52.

14 **5. SAIFI is the number of interruption each customer experiences**

15 In August 2006 weather related damage caused two prolonged outages. In November 2006 a
16 significant building fire caused the one and only feeder into a two to be disconnected for
17 protection of the fire service personnel. During the same month a lightning strike on a one-
18 feeder embedded town lead to a prolonged outage to a section of the town. In 2007 weather
19 caused-outages in five months representing nine incidents, skewed the results. Without the
20 weather factors, the results would have been 0.53.

22 **6. CAIDI is the speed at which power is restored**

23 While Westario has experienced significant weather related damages, the response time to
24 emergency calls is trending downward. As started previously, assigning two on-call personnel
25 at all times outside of regular business hours have benefited Westario Power's customers with
26 an improved response.

List of Witnesses and their Curriculum Vitae

This information will be submitted in the event that as oral hearing is required with respect to this application.

Budget Directives (Capital and Operating)

The Applicant compiles budget information for the three major components of the budgeting process: revenue forecasts; operating, maintenance and administration ("OM&A") expense forecast; and capital budgets. This budget information is compiled for both the 2008 Bridge and 2009 Test Years.

Revenue Forecast

WPI calculated its revenue forecasts from its 2009 'Ratemaker' model developed by Elenchus Research Associates ("ERA"). The revenue forecasts are based on throughput volume and existing rates for the 2008 Bridge Year and WPI's proposed rates for the 2009 Test Year. The forecasted volumes have been weather normalized as outlined in Exhibit 3, Tab 2, Schedule 1 and considers such factors as new customer additions and load for all classes of customers.

OM&A Expense Forecast:

The OM&A expenses for fiscal 2008 Bridge Year and the 2009 Test Year have been forecast using a zero based methodology. This approach ensures that budgets are developed to ensure that departmental responsibilities are met and that anticipated works will be completed during the fiscal year. WPI's operating budgeting process is described in detail in Exhibit 4.

Capital Budget:

The capital budgeting process begins with identification of WPI's distribution plant requirements; which are then evaluated against certain criteria as described in the Asset Management Policy found in Exhibit 2, Tab 3, Schedule 1, Attachment. General plant requirements are determined by each department manager. WPI's capital budgeting process is described in detail in Exhibit 2.

Changes in Methodology

WPI' s application is consistent with pervious methodologies set out by the Board with the exception of three specific areas in which the methodology has been either introduced or revised.

1. Weather Normalized Forecast

WPI is introducing a methodology for forecasting load and customer growth/decline. The methodology is explained in detail in Exhibit 3, Tab 2, Schedule 1.

2. Deferral and Variance Accounts

WPI is applying to dispose of certain variance and deferral accounts. The proposed methodology is outlined at Exhibit 5, Tab 1, Schedule 4.

3. Retail Transmission Charge Adjustment

In order to comply with the Board's rate order "Ontario Uniform Transmission Rate Order, EB-2007-0759: effect on Distributor Retail Transmission Rates", WPI has identified the reasons for not applying a multiplier to existing RTS charges. The reasoning is provided at Exhibit 4, Tab 2, Schedule 10.

Financial Statements (2006)

The following attachment is the Financial Statements for 2006.

Financial Statements of

WESTARIO POWER INC.

Year ended December 31, 2006



KPMG LLP
Chartered Accountants
140 Fullarton Street Suite 1400
PO Box 2305
London ON N6A 5P2
Canada

Telephone (519) 672-4880
Telefax (519) 672-5684
www.kpmg.ca

AUDITORS' REPORT

To the Shareholder of Westario Power Inc.

We have audited the balance sheet of Westario Power Inc. as at December 31, 2006 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, 2006 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Chartered Accountants

London, Canada

March 2, 2007



KPMG LLP, a Canadian limited liability partnership is the Canadian member of KPMG International, a Swiss nonoperating association.

WESTARIO POWER INC.

Balance Sheet

December 31, 2006, with comparative figures for 2005

	2006	2005
Assets		
Currents assets:		
Cash	\$ -	\$ 3,259,026
Accounts receivable, net of allowance	4,648,444	1,254,722
Unbilled revenue	5,623,828	5,357,690
Prepaid expenses	118,016	115,904
	<u>10,390,288</u>	<u>9,987,342</u>
Property, plant and equipment (note 2)	22,953,205	21,095,801
Regulatory assets (note 3)	3,839,156	5,443,400
Deferred organizational costs	-	21,150
Goodwill	2,214,322	2,214,322
	<u>\$ 39,396,971</u>	<u>\$ 38,762,015</u>

Liabilities and Shareholders' Equity

Current liabilities:		
Bank indebtedness	\$ 333,152	\$ -
Accounts payable and accrued liabilities	5,390,618	4,919,309
Income taxes payable (note 7)	815,146	513,317
Customer deposits and credit balances	657,748	1,839,132
Due to related parties (note 6)	833,830	1,422,889
Demand instalment loans	-	4,928,195
Current portion of long-term debt (note 5)	506,383	-
	<u>8,536,877</u>	<u>13,622,842</u>
Long-term liability (note 3)	349,673	-
Long-term debt (note 5)	11,371,834	6,853,957
Future income taxes (note 7)	753,637	1,114,461
Shareholders' equity:		
Share capital (note 8)	14,064,719	14,064,719
Retained earnings	4,320,231	3,106,036
	<u>18,384,950</u>	<u>17,170,755</u>
	<u>\$ 39,396,971</u>	<u>\$ 38,762,015</u>

See accompanying notes to financial statements.

On behalf of the Board:

Director

Director

WESTARIO POWER INC.

Statement of Earnings and Retained Earnings

December 31, 2006, with comparative figures for 2005

	2006	2005
Revenue:		
Electricity, market related	\$ 31,069,657	\$ 32,658,226
Distribution revenue	7,857,132	7,050,274
Retail services	68,890	55,653
Other income	449,317	544,618
Rental of electric property income	310,078	284,251
Late payment charges	89,530	97,768
	<u>39,844,604</u>	<u>40,690,790</u>
Expenses:		
Electricity, market related expenses	\$ 31,069,657	32,658,226
Distribution, operation and maintenance	1,547,167	1,074,238
Billing and collecting	1,094,744	1,035,386
Administration	1,444,454	1,789,070
Community relations and donations	7,270	15,797
Energy conservation	14,494	54,974
Amortization	1,382,223	1,330,308
Rent and maintenance of general plant	122,507	237,793
Interest on long-term debt	568,662	377,666
Other interest	81,827	214,453
Capital and municipal taxes	94,211	124,693
	<u>37,427,216</u>	<u>38,912,604</u>
Earnings before income taxes	2,417,388	1,778,186
Income taxes (note 7):		
Current	1,245,000	518,411
Future	(360,824)	137,461
	<u>884,176</u>	<u>655,872</u>
Net earnings	1,533,212	1,122,314
Retained earnings, beginning of year:	3,106,036	2,410,831
Dividends	(319,017)	(427,109)
Retained earnings, end of year	<u>\$ 4,320,231</u>	<u>\$ 3,106,036</u>

See accompanying notes to financial statements.

WESTARIO POWER INC.

Statement of Cash Flows

December 31, 2006, with comparative figures for 2005

	2006	2005
Cash provided by (used in):		
Operating activities:		
Net earnings	\$ 1,533,212	\$ 1,122,314
Adjustments for:		
Amortization of organizational costs	21,150	21,150
Amortization of property, plant and equipment	1,361,073	1,309,158
Change in future income tax	(360,824)	137,461
Change in non-cash operating working capital (note 9)	(9,587,472)	4,206,632
	(7,032,861)	6,796,715
Financing activities:		
Addition to property, plant and equipment	(4,717,752)	(3,491,787)
Regulatory assets	1,604,244	(666,052)
Long-term debt	5,024,261	(1,773,208)
	1,910,752	(5,931,047)
Investing activities:		
Capital contributions	1,499,275	943,353
Long-term liability	349,673	-
Dividends	(319,017)	(427,109)
	1,529,931	516,244
Increase (decrease) in cash	(3,592,178)	1,381,912
Cash, beginning of year	3,259,026	1,877,114
Cash (bank indebtedness), end of year	\$ (333,152)	\$ 3,259,026
Supplemental cash flow information:		
Interest paid	\$ 650,489	\$ 592,119
Income taxes paid	1,009,841	161,014

See accompanying notes to financial statements.

WESTARIO POWER INC.

Notes to Financial Statements

Year ended December 31, 2006

Westario Power Inc. (the "Company") was incorporated under the laws of the Province of Ontario for the purpose of distribution of electricity in accordance with legislation provided in the Energy Competition Act, 1998. Effective May 6, 2002, Western Power Inc., Hanover Electric Services Inc. and Muinto Hydro Inc. were amalgamated to form Westario Power Inc.

The principal business of Westario Power Inc. is the distribution and sale of electricity to customers in mid-western Ontario. These businesses are regulated by the Ontario Energy Board ("OEB"). The Ontario Energy Board Act, 1998 gave the OEB increased powers and responsibilities to regulate the electricity industry. These power and responsibilities include the power to approve or fix rates for licensed distributors of electricity.

1. Significant accounting policies:

The financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP") including accounting principles prescribed by the OEB in the Accounting Procedures Handbook (the "AP Handbook") for Electric Distribution Utilities, and reflect the significant accounting policies as summarized below:

(a) Rate regulation:

Westario Power Inc. is regulated by the OEB under the authority of the Ontario Energy Board Act, 1998. The OEB is charged with the responsibility of approving or fixing rates for the transmission and distribution of electricity, providing continued rate protection for rural and remote electricity customers, and for ensuring distribution companies fulfill obligations to connect and service customers

The economic impact of rate regulation is reported in these financial statements. Regulatory assets represent certain costs that may be recovered from customers in future periods through the rate-making process. In its capacity to approve or fix rates, the OEB has specified the following regulatory treatments, which have resulted in accounting treatments that differ from GAAP for enterprises operating in a non-regulatory environment.

(i) Transition costs:

Capital and operating costs incurred in respect of the transition to competitive electricity markets in Ontario (transition costs or market ready costs) have been deferred in accordance with the criteria set in the OEB's Electricity Distribution Rate Handbook and the AP Handbook. Under such regulation, certain costs are to be deferred that would be expensed when incurred under GAAP. To the extent that transition costs have been incurred which do not qualify for deferral, these costs have been expensed during the period they were incurred.

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2006

1. Significant accounting policies (continued):

(a) Rate regulation (continued):

(ii) Pre-market opening energy variance:

At December 31, 2002, the Company recognized the pre-market opening energy variance (the "variance") for the period January 1, 2001 to April 30, 2002, the date of market opening, in accordance with the AP Handbook. The variance represents the difference between the utility's cost of power purchased based on time-of-use ("TOU") rate, and the amounts billed for the cost of power to non-TOU customers at an average rate for the same period.

(iii) Settlement variances:

The Company has deferred certain port-market opening retail settlement variances in accordance with Article 490 set out in the AP Handbook. The settlement variances relate primarily to service charges, non-competitive electricity charges, and power charges. Other than the variances for cost of imported power, the nature of the settlement variances is such that their balances shall change each reporting period-end date.

(iv) Conservation and demand management costs:

Conservation and demand management ("CDM") program costs in 2006 were \$14,494 (2005-\$116,114) of which \$nil (2005-\$61,140) was capitalized. Provincial regulations allowed electricity distribution companies to apply to the OEB to adjust its distribution rates in 2005 for its approved third instalment of its market adjusted requirement ("MARR"). OEB approval in regard to this final MARR instalment is conditional on investing an amount equal to one year's incremental returns in conservation and demand management initiatives, by no later than September 30, 2007. The Company's final incremental MARR was \$659,218.

(v) OEB incremental cost assessments:

OEB costs which had been assessed to the Company in 2005, and which are incremental to amounts already included in the Company's rates, were deferred in accordance with the AP Handbook. These costs are being recovered in rates beginning in 2006. To the extent that OEB cost assessments have been incurred which do not qualify for deferral, these costs have been expenses during the period they were incurred.

(b) Revenue recognition:

In accordance with OEB regulation, the Company recognizes as revenue the regulated distribution tariffs associated with energy distributed and variances between energy purchase costs and energy billed are recorded as regulatory assets or liabilities for future rate application consideration.

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2006

1. Significant accounting policies (continued):

(b) Revenue recognition (continued):

The Company follows the practice of cycle billing customers' accounts and revenue is recognized in the period billed. An accrual is made in the accounts at December 31, for power supplied but not billed to customers between the date the meters were last read and the end of the year.

(c) Deferred organizational costs:

Deferred organizational costs, consist of costs incurred to establish the Westario Power group of companies.

(d) Spare transformers and meters:

Spare transformers and meters are classified as capital assets in accordance with guidance in the AP Handbook.

(e) Property, plant and equipment

Property, plant and equipment are recorded at amortized cost. Amortization is provided on the straight-line basis using the following annual rates:

Asset	Rate
Buildings	4%
Distribution stations	3%
Distribution lines, overhead	4%
Distribution lines, underground	4%
Distribution equipment and transformers	4%
Meters	4%
Computer software	20%

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2006

1. Significant accounting policies (continued):

(f) Impairment of long-lived assets:

Long-lived assets, including property, plant and equipment and purchased intangibles subject to amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset. Assets to be disposed of would be separately presented in the balance sheet and reported at the lower of the carrying or fair value less costs to sell, and are no longer depreciated. The assets and liabilities of a disposed group classified as held for sale would be presented separately in the appropriate assets and liability section of the balance sheet.

(g) Goodwill:

Goodwill reflects the excess of the purchase price over the fair value of net tangible assets acquired. Goodwill is not amortized, but tested for impairment on an annual basis.

(h) Income taxes:

The Company uses the asset and liability method of accounting for income taxes. Under the asset and liability method, future income tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying values of existing assets and liabilities and their respective tax bases. Future income tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future income tax assets and liabilities of a change in tax rates is recognized in income in the year that includes the date of enactment or substantive enactment.

In assessing the realizability of future income tax assets, management considers whether it is more likely than not that some portion or all of the future income tax assets will be realized. The ultimate realization of future income tax assets is dependent upon the generation of future taxable income during the period in which the temporary differences are deductible. Management considers the scheduled reversals of future income tax liabilities, the character of the future income tax asset, and tax planning strategies in making this assessment. To the extent that management believes that the realization of future income tax assets does not meet the more likely than not realization criteria, a valuation allowance is recorded against the future income tax assets.

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2006

1. Significant accounting policies (continued):

(i) Financial instruments:

The Company's financial instruments consist of accounts receivable, bank borrowings, accounts payable and accrued liabilities, income taxes payable, customer deposits and credit balances, due to related parties and demand installment loans. Management is of the opinion that the fair values of all financial assets and liabilities are not materially different from their carrying values due to the relatively short periods to maturity of the instruments. The carrying value of long-term debt approximates its fair value as debt bears interest at rates comparable to current market rates.

(j) Use of estimates:

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

2. Property, plant and equipment:

			2006	2005
	Cost	Accumulated depreciation	Net book value	Net book value
Land	\$ 242,769	-	\$ 242,769	\$ 107,769
Buildings	6,517	2,023	4,494	4,824
Distribution stations	3,073,798	859,390	2,214,408	2,355,335
Distribution lines, overhead	11,686,933	2,724,068	8,962,865	8,867,459
Distribution lines, underground	6,498,518	1,574,830	4,923,688	4,458,773
Distribution equipment and transformers	258,631	258,631	-	-
Distribution transformers	5,309,548	1,130,750	4,178,798	3,349,267
Meters	2,199,219	490,055	1,709,164	1,817,946
Computer software	267,519	209,098	58,421	111,924
Assets under construction	658,598	-	658,598	22,504
	\$ 30,202,050	\$ 7,248,845	\$ 22,953,205	\$ 21,095,801

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2006

3. Regulatory assets:

	2006	2005
Transition costs	\$ -	\$ 2,475,984
Pre-market opening energy variance	-	1,021,006
2006 OEB approved recoverable regulatory assets	6,828,639	-
Post market energy variances	782,511	3,871,546
Deferred payment in lieu of taxes	55,811	55,811
Other	162,890	302,377
	7,829,851	7,726,724
Less recovery of regulatory assets	(3,990,695)	(2,283,324)
	\$ 3,839,156	\$ 5,443,400

Recovery of regulatory amounts:

In December, 2003, the OEB permitted the Company to commence recovery of regulatory assets through distribution rates over a four-year period commencing March 1, 2005. During fiscal 2006, the OEB undertook a detailed review to validate the amounts for final recovery. The OEB has approved Phase II recovery of regulatory assets commencing May 1, 2006, which will amount to an approximate recovery of \$1,800,000 (2006-\$1,707,371) during the Company's fiscal 2007 year.

Included in regulatory assets is \$689,597 related to low voltage system charges from Hydro One Networks Inc. ("Hydro One"). A corresponding amount is being repaid to Hydro One over several years and an accrual has been recognized. The amount due in 2007 is \$339,924 and is included under "Accounts payable and accrued liabilities" and the balance of \$349,673 has been recorded as a long-term liability.

4. Bank indebtedness :

The Company has a bank operating line of credit of \$2,561,411, available by way of letters of credit. At December 31, 2006, the line was fully drawn by way of a letter of credit, issued in favour of the Independent Electricity System Operator ("IESO"), to satisfy the Company's prudential support obligation for participation in and withdrawing electricity from the IESO controlled electricity grid. The line of credit is secured by a security agreement conveying a security interest in the personal property of the Company, an unlimited guarantee from Westario Power Holdings Inc., the Company's sole shareholder, and an unlimited guarantee from Westario Power Services Inc., an affiliated company wholly-owned by Westario Power Holdings Inc.

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2006

4. Bank indebtedness (continued):

Westario Power Holdings Inc. has a bank operating line of credit of \$3,500,000 that is available to the Company. At December 31, 2006, the amount drawn by the Company under the line was nil (2005 - nil). The line of credit is secured by the unlimited guarantee of the Company, supported by a security agreement conveying a security interest in the personal property of the Company. The line of credit bears interest at bank prime rate less 0.50%. At December 31, 2006, the rate was 5.50% (2005 - 4.50%).

5. Long-term debt:

	2006	2005
Notes payable to shareholders of parent company, 5.47% payable quarterly interest only, due on demand	\$ 5,460,460	\$ 6,853,957
Term instalment loans payable to Canadian Imperial Bank of Commerce, interest at prime less 0.50% payable in blended monthly payments over 15 to 20 years, due December 2009	6,417,757	-
	11,878,217	6,853,957
Current portion of shareholders' loans	(123,428)	-
Current portion of term loans	(382,955)	-
	\$ 11,371,834	\$ 6,853,957

The shareholder notes are only due on demand to the extent the shareholder requests payment ninety days prior to year end. In the event a request is made, the Company is obligated to repay the shareholder during the following fiscal year. No repayments are required without a written request. As such, amounts recorded as current were requested by shareholders prior to October 1, 2006.

The term instalment loans are secured by a security agreement conveying a security interest in the personal property of the Company, an unlimited guarantee from Westario Power Holdings Inc., the Company's sole shareholder, and an unlimited guarantee from Westario Power Services Inc., an affiliated company wholly-owned by Westario Power Holdings Inc. At December 31, the prevailing rate of the term instalment loans are 5.50%.

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2006

6. Due to related parties:

Westario Power Inc. and Westario Power Services Inc. are wholly-owned subsidiaries of Westario Power Holdings Inc.

At the end of the year, the amounts due to related parties are as follows:

	2006	2005
Westario Power Services Inc.	\$ 735,170	\$ 960,067
Westario Power Holdings Inc.	98,660	462,822
	<u>\$ 833,830</u>	<u>\$ 1,422,889</u>

These balances are unsecured, non-interest bearing with no specific repayment terms.

Westario Power Services Inc. provides management and administrative services to the Company under the terms of a management services agreement. The cost of these services for the year was \$3,372,357 (2005 - \$3,522,680). These transactions are in the normal course of operations and are measured at the exchange amount of consideration agreed to by the related parties.

Westario Power Services Inc. also purchases or constructs capital assets for the Company. The cost of assets purchased or constructed for the year was \$3,859,216 (2005 - \$2,915,873). These transactions are in the normal course of operations and are measured at the exchange amount of consideration agreed to by the related parties.

Westario Power Holdings Inc. also provides management and administrative services to the Company. The cost of these services for the year was \$451,857 (2005 - \$441,917). These transactions are in the normal course of operations and are measured at the exchange amount of consideration agreed to by the related parties.

7. Income taxes:

(a) Income tax status:

The Company is exempt from income taxes under the Income Tax Act (Canada). Effective October 1, 2001 and pursuant to the electricity Act ("EA") (1998) (Ontario) the Company is required to make payments in lieu of tax to the Ontario Electricity Financial Corporation. The amount of payments in lieu of tax will be approximately equivalent to the income and capital taxes that would have to be paid if the Company was a taxable corporation under the Income Tax Act (Canada).

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2006

7. Income taxes (continued):

(b) Income tax rate:

The Company's effective income tax rates differed from the statutory combined federal and provincial rates primarily due to the following:

	2006	2005
Earnings before income taxes	\$ 2,417,388	\$ 1,778,186
Income tax expense based on combined federal and provincial statutory income tax rate of 36.12%(2005 - 36.12%)	\$ 873,161	\$ 642,281
Tax effect of undeductible amounts	7,195	4,391
Decrease in future income taxes resulting from statutory rate decreases	(4,213)	-
Other	8,033	9,200
Income tax expense recognized	\$ 884,176	\$ 655,872

(c) Future income taxes:

The tax effects of temporary differences that give rise to significant portions of the future tax assets and future tax liabilities at December 31 are presented below:

	2006	2005
Future income tax assets:		
Property, plant and equipment, difference between net book value and tax cost	\$ 391,051	\$ 406,591
Future income tax liabilities:		
Intangible assets, difference between net book value and tax cost	(144,023)	(135,449)
Regulatory assets	(993,540)	(1,256,235)
Other	(7,125)	(129,368)
	(1,144,688)	(1,521,052)
Net future income tax liability	\$ (753,637)	\$ (1,114,461)

The determination of whether recovery or settlement of an asset or liability will result in future income tax outflows or benefits is determined by reference to the difference between carrying values and tax basis of assets and liabilities. Management compares the carrying value and tax basis of assets and liabilities at December 31 of each year, to determine the temporary differences and the timing of the expected reversal. Taxable temporary differences give rise to future income tax liabilities while deductible temporary differences give rise to future income tax assets.

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2006

8. Share capital:

	2006	2005
Authorized:		
Unlimited common shares, voting		
Issued:		
100,000 common shares	\$ 14,064,719	\$ 14,064,719

9. Change in non-cash operating working capital:

	2006	2005
Accounts receivable, net of allowance	\$ (3,393,722)	\$ 1,315,213
Unbilled revenue	(266,138)	(157,690)
Prepaid expenses	(2,112)	(35,805)
Accounts payable and accrued liabilities	471,309	367,964
Income taxes payable	301,829	880,449
Customers deposits and credit balances	(1,181,384)	386,406
Due to related parties	(589,059)	37,972
Demand instalment loans	(4,928,195)	1,412,123
	\$ (9,587,472)	\$ 4,206,632

10. Public liability insurance:

The Company joined the Municipal Electrical Association Reciprocal Insurance Exchange ("MEARIE") in 2000. MEARIE is a pooling of public liability insurance risks of many of the municipal utilities in Ontario. All members of the pool are subject to assessment for losses experienced by the pool for the years in which they were members on a pro-rata basis based on the total of their respective service revenues. It is anticipated that should such an assessment occur it would be funded over a period of up to five years. As at December 31, 2006, no assessments have been made.

11. Credit risks

Credit risk is the risk that a counterparty will fail to discharge its obligation to the Company reducing the expected cash inflow from Company assets recorded at the balance sheet date. Credit risk can be concentrated in debtors that are similarly affected by economic or other conditions.

The Company has assessed that there are no significant concentrations of credit risk other than the present uncertainty relating to the recovery of regulatory assets. The final regulatory amount recoverable will be assessed in future years by the regulator after the audit of those costs.

Financial Statements (2007)

The following attachment is the Financial Statements for 2007.

Financial Statements of

WESTARIO POWER INC.

Year ended December 31, 2007



KPMG LLP
Chartered Accountants
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Canada

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AUDITORS' REPORT

To the Shareholder of Westario Power Inc.

We have audited the balance sheet of Westario Power Inc. 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 its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Chartered Accountants, Licensed Public Accountants

London, Canada

March 6, 2008

WESTARIO POWER INC.

Balance Sheet

December 31, 2007, with comparative figures for 2006

	2007	2006
Assets		
Currents assets:		
Cash	\$ 843,541	\$ -
Accounts receivable, net of allowance	3,398,848	4,648,444
Unbilled revenue	5,622,848	5,623,828
Prepaid expenses	174,563	118,016
	10,039,800	10,390,288
Property, plant and equipment (note 3)	25,568,650	22,953,205
Regulatory assets (note 6)	1,751,548	3,839,156
Goodwill	2,214,322	2,214,322
	\$ 39,574,320	\$ 39,396,971

Liabilities and Shareholder's Equity

Current liabilities:		
Bank indebtedness (note 5)	\$ -	\$ 333,152
Accounts payable and accrued liabilities	5,348,088	5,390,618
Income taxes payable (note 9)	270,448	815,146
Customer deposits and credit balances (note 4)	786,127	657,748
Due to related parties (note 8)	323,446	833,830
Current portion of long-term debt (note 7)	320,358	506,383
	7,048,467	8,536,877
Long-term regulatory liability (note 6)	9,749	349,673
Long-term debt (note 7)	12,948,040	11,371,834
Unrealized loss on interest rate swap (note 7)	446,464	-
Future income taxes (note 9)	242,637	753,637
Shareholder's equity:		
Share capital (note 10)	14,064,719	14,064,719
Retained earnings	4,814,244	4,320,231
	18,878,963	18,384,950
Contingency (note 14)		
Subsequent event (note 15)		
	\$ 39,574,320	\$ 39,396,971

See accompanying notes to financial statements.

On behalf of the Board:

Director

Director

WESTARIO POWER INC.

Statement of Earnings and Retained Earnings

December 31, 2007, with comparative figures for 2006

	2007	2006
Revenue:		
Electricity, market related	\$ 31,693,323	\$ 31,069,657
Distribution revenue	7,718,094	7,857,132
Retail services	67,577	68,890
Other income	596,236	449,317
Rental of electric property income	482,151	310,078
Late payment charges	85,043	89,530
	40,642,424	39,844,604
Expenses:		
Electricity, market related expenses	\$ 31,693,323	31,069,657
Distribution, operation and maintenance	791,779	1,547,167
Billing and collecting	1,222,417	1,094,744
Administration	1,696,068	1,444,454
Community relations and donations	20,392	7,270
Energy conservation	476,540	14,494
Amortization	1,562,492	1,382,223
Rent and maintenance of general plant	339,123	122,507
Interest on long-term debt	724,015	568,662
Unrealized loss on interest rate swap	446,464	-
Other interest	55,296	81,827
Capital and municipal taxes	118,449	94,211
	39,146,358	37,427,216
Earnings before income taxes	1,496,066	2,417,388
Income taxes (note 9):		
Current	1,052,000	1,245,000
Future	(511,000)	(360,824)
	541,000	884,176
Net earnings	955,066	1,533,212
Retained earnings, beginning of year:	4,320,231	3,106,036
Dividends	(461,053)	(319,017)
Retained earnings, end of year	\$ 4,814,244	\$ 4,320,231

See accompanying notes to financial statements.

WESTARIO POWER INC.

Statement of Cash Flows

December 31, 2007, with comparative figures for 2006

	2007	2006
Cash provided by (used in):		
Operating activities:		
Net earnings	\$ 955,066	\$ 1,533,212
Adjustments for:		
Amortization of organizational costs	-	21,150
Amortization of property, plant and equipment	1,562,492	1,361,073
Change in future income tax	(511,000)	(360,824)
Gain on disposal of capital assets	(33,227)	-
Unrealized loss on interest rate swap (note 7)	446,464	-
Change in non-cash operating working capital (note 11)	224,796	(9,587,472)
	2,644,591	(7,032,861)
Investing activities:		
Additions to property, plant and equipment	(4,870,486)	(4,717,752)
Regulatory assets	2,087,608	1,604,244
	(2,782,878)	(3,113,508)
Financing activities:		
Capital contributions	677,549	1,499,275
Long-term regulatory liability	(339,924)	349,673
Long-term debt	1,390,181	5,024,261
Proceeds on disposal of capital assets	48,227	-
Dividends	(461,053)	(319,017)
	1,314,980	6,554,192
Increase (decrease) in cash	1,176,693	(3,592,178)
Cash (bank indebtedness), beginning of year	(333,152)	3,259,026
Cash (bank indebtedness), end of year	\$ 843,541	\$ (333,152)
Supplemental cash flow information:		
Interest paid	\$ 764,628	\$ 650,489
Income taxes paid	1,648,630	1,009,841

See accompanying notes to financial statements.

WESTARIO POWER INC.

Notes to Financial Statements
Year ended December 31, 2007

Westario Power Inc. (the "Company") was incorporated under the laws of the Province of Ontario for the purpose of distribution of electricity in accordance with legislation provided in the Energy Competition Act, 1998. Effective May 6, 2002, Western Power Inc., Hanover Electric Services Inc. and Minto Hydro Inc. were amalgamated to form Westario Power Inc.

The principal business of Westario Power Inc. is the distribution and sale of electricity to customers in mid-western Ontario. These businesses are regulated by the Ontario Energy Board ("OEB"). The Ontario Energy Board Act, 1998 gave the OEB increased powers and responsibilities to regulate the electricity industry. These power and responsibilities include the power to approve or fix rates for licensed distributors of electricity.

1. Significant accounting policies:

The financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP") including accounting principles prescribed by the OEB in the Accounting Procedures Handbook (the "AP Handbook") for Electric Distribution Utilities, and reflect the significant accounting policies as summarized below:

(a) Rate regulation:

Westario Power Inc. is regulated by the OEB under the authority of the Ontario Energy Board Act, 1998. The OEB is charged with the responsibility of approving or fixing rates for the transmission and distribution of electricity, providing continued rate protection for rural and remote electricity customers, and for ensuring distribution companies fulfill obligations to connect and service customers.

The economic impact of rate regulation is reported in these financial statements. Regulatory assets represent certain costs that may be recovered from customers in future periods through the rate-making process. In its capacity to approve or fix rates, the OEB has specified the following regulatory treatments, which have resulted in accounting treatments that differ from GAAP for enterprises operating in a non-regulatory environment.

(i) Transition costs:

Capital and operating costs incurred in respect of the transition to competitive electricity markets in Ontario (transition costs or market ready costs) have been deferred in accordance with the criteria set in the OEB's Electricity Distribution Rate Handbook and the AP Handbook. Under such regulation, certain costs are to be deferred that would be expensed when incurred under GAAP. To the extent that transition costs have been incurred which do not qualify for deferral, these costs have been expensed during the period they were incurred.

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2007

1. Significant accounting policies (continued):

(a) Rate regulation (continued):

(ii) Pre-market opening energy variance:

At December 31, 2002, the Company recognized the pre-market opening energy variance (the "variance") for the period January 1, 2001 to April 30, 2002, the date of market opening, in accordance with the AP Handbook. The variance represents the difference between the utility's cost of power purchased based on time-of-use ("TOU") rate, and the amounts billed for the cost of power to non-TOU customers at an average rate for the same period.

(iii) Settlement variances:

The Company has deferred certain post-market opening retail settlement variances in accordance with Article 490 set out in the AP Handbook. The settlement variances relate primarily to service charges, non-competitive electricity charges, and power charges. Other than the variances for cost of imported power, the nature of the settlement variances is such that their balances shall change each reporting period-end date.

(iv) Conservation and demand management costs:

Conservation and demand management ("CDM") program costs in 2007 were \$476,540 (2006 - \$14,494) of which \$nil (2006 - \$nil) was capitalized. Provincial regulations allowed electricity distribution companies to apply to the OEB to adjust its distribution rates in 2005 for its approved third instalment of its market adjusted requirement ("MARR"). OEB approval in regard to this final MARR instalment is conditional on investing an amount equal to one year's incremental returns in conservation and demand management initiatives, by no later than April 30, 2008. The Company's final incremental MARR was \$659,218.

(v) OEB incremental cost assessments:

OEB costs which had been assessed to the Company in 2005, and which are incremental to amounts already included in the Company's rates, were deferred in accordance with the AP Handbook. These costs are being recovered in rates beginning in 2006. To the extent that OEB cost assessments have been incurred which do not qualify for deferral, these costs have been expensed during the period they were incurred.

(b) Cash

Cash consists of cash on hand and bank balances.

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2007

1. Significant accounting policies (continued):

(c) Revenue recognition:

In accordance with OEB regulation, the Company recognizes as revenue the regulated distribution tariffs associated with energy distributed and variances between energy purchase costs and energy billed are recorded as regulatory assets or liabilities for future rate application consideration.

The Company follows the practice of cycle billing customers' accounts and revenue is recognized in the period billed. An accrual is made in the accounts at December 31, for power supplied but not billed to customers between the date the meters were last read and the end of the year.

(d) Spare transformers and meters:

Spare transformers and meters are classified as capital assets in accordance with guidance in the AP Handbook.

(e) Property, plant and equipment

Property, plant and equipment are recorded at amortized cost. Amortization is provided on a straight-line basis using the following annual rates:

Asset	Rate
Buildings	4%
Distribution stations	3%
Distribution lines, overhead	4%
Distribution lines, underground	4%
Distribution equipment and transformers	4%
Meters	4%
Computer software	20%

(f) Contributed capital:

Contributions are received from developers and contractors for capital costs incurred by the Company. These contributions are included as a reduction to the cost of the related capital assets when those assets are placed in service.

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2007

1. Significant accounting policies (continued):

(g) Impairment of long-lived assets:

Long-lived assets, including property, plant and equipment and purchased intangibles subject to amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset. Assets to be disposed of would be separately presented in the balance sheet and reported at the lower of the carrying or fair value less costs to sell, and are no longer depreciated. The assets and liabilities of a disposed group classified as held for sale would be presented separately in the appropriate assets and liability section of the balance sheet.

(h) Goodwill:

Goodwill reflects the excess of the purchase price over the fair value of net tangible assets acquired. Goodwill is not amortized, but tested for impairment on an annual basis. No goodwill was impaired during the year.

(i) Income taxes:

The Company uses the asset and liability method of accounting for income taxes. Under the asset and liability method, future income tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying values of existing assets and liabilities and their respective tax bases. Future income tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future income tax assets and liabilities of a change in tax rates is recognized in income in the year that includes the date of enactment or substantive enactment.

In assessing the realizability of future income tax assets, management considers whether it is more likely than not that some portion or all of the future income tax assets will be realized. The ultimate realization of future income tax assets is dependent upon the generation of future taxable income during the period in which the temporary differences are deductible. Management considers the scheduled reversals of future income tax liabilities, the character of the future income tax asset, and tax planning strategies in making this assessment. To the extent that management believes that the realization of future income tax assets does not meet the more likely than not realization criteria, a valuation allowance is recorded against the future income tax assets.

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2007

1. Significant accounting policies (continued):

(j) Derivative instruments:

Derivative financial instruments are contracts that require or provide the opportunity to exchange cash flows or payments determined by applying certain rates, indices or changes therein to notional contract amounts. The Company uses derivative financial instruments, primarily interest rate swaps, in order to manage interest rate exposure. The Company's policy is not to utilize financial instruments for trading or speculative purposes. From January 1, 2007, derivatives are carried at fair value and are reported on the Balance Sheet as other assets, where they have a positive fair value and as derivative financial liabilities where they have a negative fair value.

(k) Use of estimates:

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

2. Change in accounting policies:

On January 1, 2007, the Company adopted the following new accounting standards issued by the Canadian Institute of Chartered Accountants:

- (i) Section 1530, "Comprehensive Income", establishes standards for reporting and displaying comprehensive income. Comprehensive income is defined as the change in equity from transactions and other events from non-owner sources. Other comprehensive income refers to items recognized in comprehensive income but that are excluded from net income calculated in accordance with Canadian generally accepted accounting policies.
- (ii) Section 3251, "Equity", establishes standards for the presentation of equity in the reporting period.
- (iii) Section 3855, "Financial Instruments - Recognition and Measurement", establishes standards for recognizing and measuring financial instruments, namely financial assets, financial liabilities and derivatives.
- (iv) Section 3861, "Financial Instruments - Disclosure and Presentation", establishes standards for presentation and disclosure of financial instruments, namely financial assets, financial liabilities and derivatives.
- (v) Section 3865, "Hedges", establishes standards for which hedge accounting is permissible and how it may be applied. There were no transitional adjustments on adoption of these standards.

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2007

2. Change in accounting policies (continued):

Under these new standards, all financial instruments are required to be initially measured at fair value and classified into one of the following five categories: held for trading, held-to-maturity investments, loans and receivables, available-for-sale financial assets or other financial liabilities. Subsequent measurement and recognition of changes in fair value of financial instruments depend on their initial classification.

The Company has implemented the following classifications:

Held-for-trading

Cash is designated as "Financial Assets Held for Trading". These financial assets are marked-to-market through net earnings at each period end.

Loans and receivables

Accounts receivable are designated as "Loans and Receivables". After their initial fair value measurement, they are measured at amortized cost using the effective interest rate method.

Other financial liabilities

Accounts payable and accrued liabilities, amounts due to related parties, and long-term debt are designated as "Other Financial Liabilities". After their initial fair value measurement, they are measured at amortized cost using the effective interest rate method.

These accounting policy changes were adopted on a prospective basis with no restatement of prior period financial statements.

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2007

3. Property, plant and equipment:

		2007		2006	
	Cost	Accumulated depreciation	Net book value	Net book value	
Land	\$ 227,769	-	\$ 227,769	\$ 242,769	
Buildings	2,450,304	100,107	2,350,197	4,494	
Distribution stations	3,157,391	1,006,924	2,150,467	2,214,408	
Distribution lines, overhead	12,304,607	3,276,110	9,028,497	8,962,865	
Distribution lines, underground	7,383,096	1,913,271	5,469,825	4,923,688	
Distribution equipment and transformers	258,631	258,631	-	-	
Distribution transformers	5,879,341	1,393,705	4,485,636	4,178,798	
Meters	2,390,152	599,990	1,790,162	1,709,164	
Computer software	267,519	262,601	4,918	58,421	
Assets under construction	61,179	-	61,179	658,598	
	\$ 34,379,989	\$ 8,811,339	\$ 25,568,650	\$ 22,953,205	

4. Customer deposits and credit balances:

Customer deposits include security deposits for energy consumption bearing interest at a rate of prime less 2% per annum and developer deposits held in accordance with regulation.

5. Bank indebtedness:

The Company has a bank operating line of credit of \$1,897,399, available by way of letters of credit. At December 31, 2007, the line was fully drawn by way of a letter of credit, issued in favour of the Independent Electricity System Operator ("IESO"), to satisfy the Company's prudential support obligation for participation in and withdrawing electricity from the IESO controlled electricity grid. The line of credit is secured by a security agreement conveying a security interest in the personal property of the Company, an unlimited guarantee from Westario Power Holdings Inc., the Company's sole shareholder, and an unlimited guarantee from Westario Power Services Inc., an affiliated company wholly-owned by Westario Power Holdings Inc.

Westario Power Holdings Inc., the Company's sole shareholder, has a bank operating line of credit of \$3,500,000 that is available to the Company. At December 31, 2007, the amount drawn by the Company under the line was \$nil (2006 - \$nil). The line of credit is secured by the unlimited guarantee of the company, supported by a security agreement conveying a security interest in the personal property of the Company. The line of credit bears interest at bank prime rate less 0.50%. At December 31, 2007 the rate was 5.50% (2006 - 5.50%).

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2007

6. Regulatory assets:

	2007	2006
2006 OEB approved recoverable regulatory assets	\$ 7,005,341	\$ 6,828,639
Post market energy variances	590,929	782,511
Deferred payment in lieu of taxes	55,811	55,811
Other	94,118	162,890
	7,746,199	7,829,851
Less recovery of regulatory assets	(5,994,651)	(3,990,695)
	\$ 1,751,548	\$ 3,839,156

Recovery of regulatory amounts:

In December, 2003, the OEB permitted the Company to commence recovery of regulatory assets through distribution rates over a four-year period commencing March 1, 2005. During fiscal 2006, the OEB undertook a detailed review to validate the amounts for final recovery. The OEB has approved Phase II recovery of regulatory assets commencing May 1, 2006, which will amount to an approximate recovery of \$1,010,690 (2007 - \$1,784,753) during the Company's fiscal 2008 year.

Included in regulatory assets is \$689,597 related to low voltage system charges from Hydro One Networks Inc. ("Hydro One"). A corresponding amount is being repaid to Hydro One over several years and an accrual has been recognized. The amount due in 2008 is \$339,924 and is included under "Accounts payable and accrued liabilities" and the balance of \$9,749 has been recorded as a long-term liability.

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2007

7. Long-term debt:

	2007	2006
Notes payable to shareholders of parent company, 5.47% payable quarterly interest only, due on demand	\$ 5,260,460	\$ 5,583,888
Non-revolving term instalment loan bearing interest at the Banker's Acceptance rate of 5.33% plus a stamping fee of 0.80%, payable in blended monthly instalments of \$48,700, due December 2010	5,534,694	-
Non-revolving term instalment loan bearing interest at the Banker's Acceptance rate of 5.38% plus a stamping fee of 0.80%, payable in blended monthly instalments of \$18,150, due December 2010	2,473,244	-
Term instalment loans bearing interest at prime less 0.50%, payable in blended monthly instalments over 15 to 20 years, due December 2009	-	6,294,329
	13,268,398	11,878,217
Current portion of shareholders' loans	-	(123,428)
Current portion of term loans	(320,358)	(382,955)
	\$ 12,948,040	\$ 11,371,834

The shareholder notes are only due on demand to the extent the shareholder requests payment ninety days prior to year end. In the event a request is made, the Company is obligated to repay the shareholder during the following fiscal year. No repayments are required without a written request. No amounts were requested by shareholders of the parent company on or before September 30, 2007.

The term instalment loans are secured by a security agreement conveying a security interest in the personal property of the Company, acknowledgement of fire insurance and an unlimited guarantee from Westario Power Holdings Inc., the Company's sole shareholder, and an unlimited guarantee from Westario Power Services Inc., an affiliated company wholly-owned by Westario Power Holdings Inc.

Westario Power Inc. has entered into an interest rate swap agreement on a notional principal of \$5,655,638 as at June 28, 2007 maturing on June 28, 2022. The swap is a receive variable, pay fixed swap with the CIBC World Markets. This agreement has effectively converted variable interest rates on the unsecured Banker's Acceptances to an effective fixed interest rate of 5.47% plus stamping fee.

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2007

7. Long-term debt (continued):

Westario Power Inc. has entered into an interest rate swap agreement on a notional principal of \$2,500,000 as at July 3, 2007 maturing on July 3, 2027. The swap is a receive variable, pay fixed swap with the CIBC World Markets. This agreement has effectively converted variable interest rates on the unsecured Banker's Acceptances to an effective fixed interest rate of 5.38% plus stamping fee.

The two swaps entered into by Westario Power Inc. do not meet the standard to apply hedge accounting. Accordingly, the interest rate swap contract is marked to market at each year end with the gain or loss recorded in the income statement. The loss recorded in 2007 was \$446,464.

8. Due to related parties:

Westario Power Inc. and Westario Power Services Inc. are wholly-owned subsidiaries of Westario Power Holdings Inc.

At the end of the year, the amounts due to related parties are as follows:

	2007		2006	
Westario Power Services Inc.	\$	175,299	\$	735,170
Westario Power Holdings Inc.		148,147		98,660
	\$	323,446	\$	833,830

These balances are unsecured, non-interest bearing with no specific repayment terms.

Westario Power Services Inc. provides management and administrative services to the Company under the terms of a management services agreement. The cost of these services for the year was \$3,277,651 (2006 - \$3,372,357). These transactions are in the normal course of operations and are measured at the exchange amount of consideration agreed to by the related parties.

Westario Power Services Inc. purchases from and/or constructs capital assets for the Company. The cost of assets purchased or constructed for the year was \$3,359,910 (2006 - \$3,859,216). These transactions are in the normal course of operations and are measured at the exchange amount of consideration agreed to by the related parties.

Westario Power Holdings Inc. also provides management and administrative services to the Company. The cost of these services for the year was \$462,643 (2006 - \$451,857). These transactions are in the normal course of operations and are measured at the exchange amount of consideration agreed to by the related parties.

The Company received rental income totalling \$352,110 (2006 - \$180,000) from Westario Power Services Inc. These transactions are in the normal course of operations and are measured at the exchange amount of consideration agreed to by the related parties.

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2007

9. Income taxes:

(a) Income tax status:

The Company is exempt from income taxes under the Income Tax Act (Canada). Effective October 1, 2001 and pursuant to the electricity Act ("EA") (1998) (Ontario) the Company is required to make payments in lieu of tax to the Ontario Electricity Financial Corporation. The amount of payments in lieu of tax will be approximately equivalent to the income and capital taxes that would have to be paid if the Company was a taxable corporation under the Income Tax Act (Canada).

(b) Income tax rate:

The Company's effective income tax rates differed from the statutory combined federal and provincial rates primarily due to the following:

	2007	2006
Earnings before income taxes	\$ 1,496,066	\$ 2,417,388
Income tax expense based on combined federal and provincial statutory income tax rate of 36.12% (2006 - 36.12%)	\$ 540,379	\$ 873,161
Tax effect of undeductible amounts	6,991	7,195
Impact on future income taxes resulting from statutory rate decreases	57,393	(4,213)
Other	(63,763)	8,033
Income tax expense recognized	\$ 541,000	\$ 884,176

(c) Future income taxes:

The tax effects of temporary differences that give rise to significant portions of the future tax assets and future tax liabilities at December 31 are presented below:

	2007	2006
Future income tax assets:		
Property, plant and equipment, difference between net book value and tax cost	\$ 344,940	\$ 391,051
Unrealized interest for tax purposes	129,475	-
	474,415	391,051
Future income tax liabilities:		
Intangible assets, difference between net book value and tax cost	(145,671)	(144,023)
Regulatory assets	(570,618)	(993,540)
Other	(763)	(7,125)
	(717,052)	(1,144,688)
Net future income tax liability	\$ (242,637)	\$ (753,637)

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2007

9. Income taxes (continued):

The determination of whether recovery or settlement of an asset or liability will result in future income tax outflows or benefits is determined by reference to the difference between carrying values and tax basis of assets and liabilities. Management compares the carrying value and tax basis of assets and liabilities at December 31 of each year, to determine the temporary differences and the timing of the expected reversal. Taxable temporary differences give rise to future income tax liabilities while deductible temporary differences give rise to future income tax assets.

10. Share capital:

	2007	2006
Authorized:		
Unlimited common shares, voting		
Issued:		
100,000 common shares	\$ 14,064,719	\$ 14,064,719

11. Change in non-cash operating working capital:

	2007	2006
Accounts receivable, net of allowance	\$ 1,249,596	\$ (3,393,722)
Unbilled revenue	980	(266,138)
Prepaid expenses	(56,547)	(2,112)
Accounts payable and accrued liabilities	(42,530)	471,309
Income taxes payable	(544,698)	301,829
Customers deposits and credit balances	128,379	(1,181,384)
Due to related parties	(510,384)	(589,059)
Demand instalment loans	-	(4,928,195)
	\$ 224,796	\$ (9,587,472)

12. Public liability insurance:

The Company joined the Municipal Electrical Association Reciprocal Insurance Exchange ("MEARIE") in 2000. MEARIE is a pooling of public liability insurance risks of many of the municipal utilities in Ontario. All members of the pool are subject to assessment for losses experienced by the pool for the years in which they were members on a pro-rata basis based on the total of their respective service revenues. It is anticipated that should such an assessment occur it would be funded over a period of up to five years. As at December 31, 2007, no assessments have been made.

WESTARIO POWER INC.

Notes to Financial Statements (continued)

Year ended December 31, 2007

13. Credit risks:

Credit risk is the risk that a counterparty will fail to discharge its obligation to the Company reducing the expected cash inflow from Company assets recorded at the balance sheet date. Credit risk can be concentrated in debtors that are similarly affected by economic or other conditions.

The Company has assessed that there are no significant concentrations of credit risk other than the present uncertainty relating to the recovery of regulatory assets. The final regulatory amount recoverable will be assessed in future years by the regulator after the audit of those costs.

14. Contingency:

The Company has a future asset retirement obligation related to an environmental liability to dispose of wooden creosote-treated hydro poles. Management is currently unable to estimate the future costs for disposal at this time as a detailed inventory of creosote-treated poles in use and their remaining useful lives are not available.

15. Subsequent event:

On January 1, 2008 Westario Power Services Inc., Westario Power Inc. and Westario Power Holdings Inc. amalgamated to form a new company called Westario Power Inc.

Pro Forma Statements (2008)

The following attachment is the Pro-Forma Statements for 2008.

Westario Power Inc. (ED-2002-0515)

2009 EDR Application (EB-2008-0250)

August 22, 2008

G1 Finalize 2008 Pro-forma Projections*Enter final adjustments to projected account balances for 2008*

Account Grouping	Account Description	Final
		Projection
1050-Current Assets	1005-Cash	1,578,458
	1040-Other Special Deposits	467,000
	1100-Customer Accounts Receivable	3,489,000
	1102-Accounts Receivable - Services	(45,000)
	1104-Accounts Receivable - Recoverable Work	63,000
	1120-Accrued Utility Revenues	5,623,000
	1130-Accumulated Provision for Uncollectible Accounts-- Credit	(360,500)
	1180-Prepayments	191,000
	1190-Miscellaneous Current and Accrued Assets	120,000
1100-Inventory	1330-Plant Materials and Operating Supplies	718,000
1150-Non-Current Assets	1405-Long Term Investments in Non-Associated Companies	28,000
	1460-Other Non-Current Assets	240,000
1200-Other Assets and Deferred Charges	1508-Other Regulatory Assets	263,441
	1518-RCVARetail	(49,122)
	1548-RCVASTR	85,300
	1550-LV Variance Account	845,941
	1555-Smart Meters Capital Variance Account	(132,914)
	1562-Deferred Payments in Lieu of Taxes	184,666
	1563-Account 1563 - Deferred PILs Contra Account	(128,855)

Westario Power Inc. (ED-2002-0515)

2009 EDR Application (EB-2008-0250)

August 22, 2008

G1 Finalize 2008 Pro-forma Projections

Enter final adjustments to projected account balances for 2008

Account Grouping	Account Description	Final
		Projection
	1565-Conservation and Demand Management Expenditures and Recoveries	(52,580)
	1566-CDM Contra Account	52,580
	1580-RSVAWMS	(623,092)
	1582-RSVAONE-TIME	35,229
	1584-RSVANW	(387,859)
	1586-RSVACN	(1,974,024)
	1588-RSVAPOWER	2,924,261
	1590-Recovery of Regulatory Asset Balances	73,311
1450-Distribution Plant	1805-Land	227,769
	1808-Buildings and Fixtures	2,450,304
	1820-Distribution Station Equipment - Normally Primary below 50 kV	3,588,176
	1830-Poles, Towers and Fixtures	5,230,361
	1835-Overhead Conductors and Devices	7,932,317
	1840-Underground Conduit	2,809,409
	1845-Underground Conductors and Devices	6,633,637
	1850-Line Transformers	6,721,963
	1855-Services	3,229,743
	1860-Meters	2,716,274
1500-General Plant	1865-Other Installations on Customer's Premises	1,635
	1915-Office Furniture and Equipment	245,418

Westario Power Inc. (ED-2002-0515)

2009 EDR Application (EB-2008-0250)

August 22, 2008

G1 Finalize 2008 Pro-forma Projections*Enter final adjustments to projected account balances for 2008*

Account Grouping	Account Description	Final
		Projection
	1920-Computer Equipment - Hardware	396,174
	1925-Computer Software	714,890
	1930-Transportation Equipment	1,634,555
	1935-Stores Equipment	19,842
	1940-Tools, Shop and Garage Equipment	229,420
	1945-Measurement and Testing Equipment	51,482
	1950-Power Operated Equipment	30,011
	1955-Communication Equipment	99,188
	1960-Miscellaneous Equipment	27,970
	1975-Load Management Controls - Utility Premises	258,631
1550-Other Capital Assets	1995-Contributions and Grants - Credit	(5,610,728)
	2055-Construction Work in Progress--Electric	50,000
	2060-Electric Plant Acquisition Adjustment	2,888,247
1600-Accumulated Amortization	2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(12,213,859)
	2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	(673,925)
1650-Current Liabilities	2205-Accounts Payable	(4,000,000)
	2208-Customer Credit Balances	(320,000)
	2210-Current Portion of Customer Deposits	(467,000)
	2220-Miscellaneous Current and Accrued Liabilities	(448,500)
	2240-Accounts Payable to Associated Companies	
	2260-Current Portion of Long Term Debt	(340,594)
	2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	(801,261)
1700-Non-Current Liabilities	2306-Employee Future Benefits	(342,850)
	2350-Future Income Tax - Non-Current	(128,224)
	2405-Other Regulatory Liabilities	(175,000)
1800-Long-Term Debt	2520-Other Long Term Debt	(5,260,461)
	2525-Term Bank Loans - Long Term Portion	(7,793,449)

Westario Power Inc. (ED-2002-0515)

2009 EDR Application (EB-2008-0250)

August 22, 2008

G1 Finalize 2008 Pro-forma Projections*Enter final adjustments to projected account balances for 2008*

Account Grouping	Account Description	Final Projection
1850-Shareholders' Equity	3005-Common Shares Issued	(15,380,920)
	3030-Miscellaneous Paid-In Capital	(2,888,247)
	3040-Appropriated Retained Earnings	(15,000)
	3045-Unappropriated Retained Earnings	(6,068,485)
	3046-Balance Transferred From Income	(467,553)
	3049-Dividends Payable-Common Shares	1,980,396
3000-Sales of Electricity	4006-Residential Energy Sales	(11,603,654)
	4010-Commercial Energy Sales	(9,463,331)
	4025-Street Lighting Energy Sales	(242,949)
	4030-Sentinel Lighting Energy Sales	(978)
	4035-General Energy Sales	(4,167,050)
	4055-Energy Sales for Resale	
	4062-Billed WMS	(2,898,410)
	4066-Billed NW	(1,991,951)
	4068-Billed CN	(2,400,826)
	4075-Billed-LV	(253,892)
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	(7,816,601)
	4082-Retail Services Revenues	(12,500)
	4084-Service Transaction Requests (STR) Revenues	(2,000)
3100-Other Operating Revenues	4210-Rent from Electric Property	(129,630)
	4215-Other Utility Operating Income	
	4225-Late Payment Charges	(85,000)
	4235-Miscellaneous Service Revenues	(292,645)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	(40,000)
	4355-Gain on Disposition of Utility and Other Property	(7,500)
	4375-Revenues from Non-Utility Operations	

Westario Power Inc. (ED-2002-0515)

2009 EDR Application (EB-2008-0250)

August 22, 2008

G1 Finalize 2008 Pro-forma Projections*Enter final adjustments to projected account balances for 2008*

Account Grouping	Account Description	Final
		Projection
	4380-Expenses of Non-Utility Operations	
	4390-Miscellaneous Non-Operating Income	(7,500)
3200-Investment Income	4405-Interest and Dividend Income	(318,459)
3350-Power Supply Expenses	4705-Power Purchased	25,477,962
	4708-Charges-WMS	2,898,410
	4714-Charges-NW	1,991,951
	4716-Charges-CN	2,400,826
	4750-Charges-LV	253,892
3500-Distribution Expenses - Operation	5017-Distribution Station Equipment - Operation Supplies and Expenses	
	5020-Overhead Distribution Lines and Feeders - Operation Labour	
	5035-Overhead Distribution Transformers- Operation	
	5040-Underground Distribution Lines and Feeders - Operation Labour	322,475
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	10,000
	5065-Meter Expense	
	5075-Customer Premises - Materials and Expenses	
	5085-Miscellaneous Distribution Expense	
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	18,300
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	25,900

Westario Power Inc. (ED-2002-0515)

2009 EDR Application (EB-2008-0250)

August 22, 2008

G1 Finalize 2008 Pro-forma Projections

Enter final adjustments to projected account balances for 2008

Account Grouping	Account Description	Final
		Projection
	5114-Maintenance of Distribution Station Equipment	204,750
	5120-Maintenance of Poles, Towers and Fixtures	58,920
	5125-Maintenance of Overhead Conductors and Devices	27,625
	5130-Maintenance of Overhead Services	74,650
	5135-Overhead Distribution Lines and Feeders - Right of Way	230,250
	5145-Maintenance of Underground Conduit	
	5150-Maintenance of Underground Conductors and Devices	4,600
	5155-Maintenance of Underground Services	98,000
	5160-Maintenance of Line Transformers	453,600
	5175-Maintenance of Meters	309,175
3650-Billing and Collecting	5305-Supervision	18,300
	5310-Meter Reading Expense	272,000
	5315-Customer Billing	371,035
	5320-Collecting	384,700
	5335-Bad Debt Expense	100,000
	5340-Miscellaneous Customer Accounts Expenses	
3700-Community Relations	5410-Community Relations - Sundry	13,470
	5415-Energy Conservation	
	5420-Community Safety Program	10,000

Westario Power Inc. (ED-2002-0515)

2009 EDR Application (EB-2008-0250)

August 22, 2008

G1 Finalize 2008 Pro-forma Projections*Enter final adjustments to projected account balances for 2008*

Account Grouping	Account Description	Final
		Projection
	5425-Miscellaneous Customer Service and Informational Expenses	
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	128,125
	5610-Management Salaries and Expenses	631,100
	5615-General Administrative Salaries and Expenses	145,150
	5620-Office Supplies and Expenses	326,125
	5630-Outside Services Employed	311,490
	5635-Property Insurance	97,125
	5640-Injuries and Damages	2,500
	5655-Regulatory Expenses	59,900
	5660-General Advertising Expenses	11,900
	5665-Miscellaneous General Expenses	36,600
	5670-Rent	
	5675-Maintenance of General Plant	100,750
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	1,720,456
3900-Interest Expense	6005-Interest on Long Term Debt	775,350

Westario Power Inc. (ED-2002-0515)

2009 EDR Application (EB-2008-0250)

August 22, 2008

G1 Finalize 2008 Pro-forma Projections

Enter final adjustments to projected account balances for 2008

Account Grouping	Account Description	Final
		Projection
	6035-Other Interest Expense	38,100
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	50,600
4000-Income Taxes	6110-Income Taxes	801,261
	6115-Provision for Future Income Taxes	
4100-Extraordinary & Other Items	6205-Donations	

Pro Forma Statements (2009)

The following attachment is the Pro-Forma Statements for 2009.

Westario Power Inc. (ED-2002-0515)

2009 EDR Application (EB-2008-0250)

August 22, 2008

G2 Finalize 2009 Pro-forma Projections

Enter final adjustments to projected account balances for 2009 at Existing Rates

Account Grouping	Account Description	Final Projection
1050-Current Assets	1005-Cash	2,420,807
	1040-Other Special Deposits	467,000
	1100-Customer Accounts Receivable	3,489,000
	1102-Accounts Receivable - Services	(45,000)
	1104-Accounts Receivable - Recoverable Work	63,000
	1120-Accrued Utility Revenues	5,623,000
	1130-Accumulated Provision for Uncollectible Accounts-- Credit	(360,500)
	1180-Prepayments	191,000
	1190-Miscellaneous Current and Accrued Assets	120,000
1100-Inventory	1330-Plant Materials and Operating Supplies	718,000
1150-Non-Current Assets	1405-Long Term Investments in Non-Associated Companies	28,000
	1460-Other Non-Current Assets	186,667
1200-Other Assets and Deferred Charges	1508-Other Regulatory Assets	271,829
	1518-RCVARetail	(50,640)
	1548-RCVASTR	87,894
	1550-LV Variance Account	872,332
	1555-Smart Meters Capital Variance Account	(137,040)
	1562-Deferred Payments in Lieu of Taxes	187,584
	1563-Account 1563 - Deferred PILs Contra Account	(131,773)

Westario Power Inc. (ED-2002-0515)

2009 EDR Application (EB-2008-0250)

August 22, 2008

G2 Finalize 2009 Pro-forma Projections

Enter final adjustments to projected account balances for 2009 at Existing Rates

Account Grouping	Account Description	Final
		Projection
	1565-Conservation and Demand Management Expenditures and Recoveries	(52,580)
	1566-CDM Contra Account	52,580
	1580-RSVAWMS	(617,481)
	1582-RSVAONE-TIME	39,046
	1584-RSVANW	(386,000)
	1586-RSVACN	(2,002,068)
	1588-RSVAPOWER	3,108,476
	1590-Recovery of Regulatory Asset Balances	75,785
1450-Distribution Plant	1805-Land	227,769
	1808-Buildings and Fixtures	2,466,304
	1820-Distribution Station Equipment - Normally Primary below 50 kV	3,829,176
	1830-Poles, Towers and Fixtures	5,848,861
	1835-Overhead Conductors and Devices	8,775,517
	1840-Underground Conduit	2,809,409
	1845-Underground Conductors and Devices	7,139,137
	1850-Line Transformers	7,257,963
	1855-Services	3,265,243
	1860-Meters	2,746,274
1500-General Plant	1865-Other Installations on Customer's Premises	1,635
	1915-Office Furniture and Equipment	247,418

Westario Power Inc. (ED-2002-0515)

2009 EDR Application (EB-2008-0250)

August 22, 2008

G2 Finalize 2009 Pro-forma Projections*Enter final adjustments to projected account balances for 2009 at Existing Rates*

Account Grouping	Account Description	Final
		Projection
	1920-Computer Equipment - Hardware	407,974
	1925-Computer Software	750,290
	1930-Transportation Equipment	1,654,555
	1935-Stores Equipment	92,342
	1940-Tools, Shop and Garage Equipment	274,420
	1945-Measurement and Testing Equipment	51,482
	1950-Power Operated Equipment	72,011
	1955-Communication Equipment	99,188
	1960-Miscellaneous Equipment	27,970
	1975-Load Management Controls - Utility Premises	258,631
1550-Other Capital Assets	1995-Contributions and Grants - Credit	(6,094,728)
	2055-Construction Work in Progress--Electric	50,000
	2060-Electric Plant Acquisition Adjustment	2,888,247
1600-Accumulated Amortization	2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(14,088,448)
	2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	(673,925)
1650-Current Liabilities	2205-Accounts Payable	(4,000,000)
	2208-Customer Credit Balances	(320,000)
	2210-Current Portion of Customer Deposits	(467,000)
	2220-Miscellaneous Current and Accrued Liabilities	(448,500)
	2260-Current Portion of Long Term Debt	(362,105)
	2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	(456,436)
1700-Non-Current Liabilities	2306-Employee Future Benefits	(347,650)
	2350-Future Income Tax - Non-Current	(128,000)
	2405-Other Regulatory Liabilities	(39,000)
1800-Long-Term Debt	2520-Other Long Term Debt	(5,260,461)
	2525-Term Bank Loans - Long Term Portion	(9,431,344)
1850-Shareholders' Equity	3005-Common Shares Issued	(15,380,920)

Westario Power Inc. (ED-2002-0515)

2009 EDR Application (EB-2008-0250)

August 22, 2008

G2 Finalize 2009 Pro-forma Projections*Enter final adjustments to projected account balances for 2009 at Existing Rates*

Account Grouping	Account Description	Final Projection
	3030-Miscellaneous Paid-In Capital	(2,888,247)
	3040-Appropriated Retained Earnings	(15,000)
	3045-Unappropriated Retained Earnings	(6,536,038)
	3046-Balance Transferred From Income	(670,813)
	3049-Dividends Payable-Common Shares	2,147,879
3000-Sales of Electricity	4006-Residential Energy Sales	(11,620,718)
	4010-Commercial Energy Sales	(9,477,248)
	4025-Street Lighting Energy Sales	(243,678)
	4030-Sentinel Lighting Energy Sales	(978)
	4035-General Energy Sales	(4,173,134)
	4062-Billed WMS	(2,902,710)
	4066-Billed NW	(1,994,897)
	4068-Billed CN	(2,404,377)
	4075-Billed-LV	(253,892)
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	(7,859,217)
	4082-Retail Services Revenues	(12,500)
	4084-Service Transaction Requests (STR) Revenues	(2,000)
3100-Other Operating Revenues	4210-Rent from Electric Property	(129,630)
	4225-Late Payment Charges	(90,000)
	4235-Miscellaneous Service Revenues	(330,800)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	(10,000)
	4355-Gain on Disposition of Utility and Other Property	(500)
	4390-Miscellaneous Non-Operating Income	(7,500)
3200-Investment Income	4405-Interest and Dividend Income	(225,324)
3350-Power Supply Expenses	4705-Power Purchased	25,515,756
	4708-Charges-WMS	2,902,710

Westario Power Inc. (ED-2002-0515)**2009 EDR Application (EB-2008-0250)****August 22, 2008****G2 Finalize 2009 Pro-forma Projections***Enter final adjustments to projected account balances for 2009 at Existing Rates*

Account Grouping	Account Description	Final
		Projection
	4714-Charges-NW	1,994,897
	4716-Charges-CN	2,404,377
	4750-Charges-LV	253,892
3500-Distribution Expenses - Operation	5040-Underground Distribution Lines and Feeders - Operation Labour	469,400
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	10,000
	5075-Customer Premises - Materials and Expenses	1,000
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	16,775
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	
	5114-Maintenance of Distribution Station Equipment	246,800
	5120-Maintenance of Poles, Towers and Fixtures	77,400
	5125-Maintenance of Overhead Conductors and Devices	131,200
	5130-Maintenance of Overhead Services	106,600
	5135-Overhead Distribution Lines and Feeders - Right of Way	270,900
	5150-Maintenance of Underground Conductors and Devices	
	5155-Maintenance of Underground Services	112,000
	5160-Maintenance of Line Transformers	108,000

Westario Power Inc. (ED-2002-0515)

2009 EDR Application (EB-2008-0250)

August 22, 2008

G2 Finalize 2009 Pro-forma Projections

Enter final adjustments to projected account balances for 2009 at Existing Rates

Account Grouping	Account Description	Final
		Projection
	5175-Maintenance of Meters	95,000
3650-Billing and Collecting	5305-Supervision	16,775
	5310-Meter Reading Expense	272,000
	5315-Customer Billing	387,725
	5320-Collecting	416,400
	5335-Bad Debt Expense	150,000
3700-Community Relations	5410-Community Relations - Sundry	20,500
	5420-Community Safety Program	15,000
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	130,000
	5610-Management Salaries and Expenses	689,400
	5615-General Administrative Salaries and Expenses	143,300
	5620-Office Supplies and Expenses	368,650
	5630-Outside Services Employed	178,500
	5635-Property Insurance	101,125
	5640-Injuries and Damages	2,500
	5655-Regulatory Expenses	140,000
	5660-General Advertising Expenses	3,000
	5665-Miscellaneous General Expenses	33,550

Westario Power Inc. (ED-2002-0515)

2009 EDR Application (EB-2008-0250)

August 22, 2008

G2 Finalize 2009 Pro-forma Projections

Enter final adjustments to projected account balances for 2009 at Existing Rates

Account Grouping	Account Description	Final
		Projection
	5675-Maintenance of General Plant	98,325
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	1,829,713
3900-Interest Expense	6005-Interest on Long Term Debt	802,083
	6035-Other Interest Expense	40,000
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	56,600
4000-Income Taxes	6110-Income Taxes	456,436

Cost of Power Projections

		2009	2008
3000-Sales of Electricity	4006-Residential Energy Sales	(11,620,718)	(11,603,654)
	4010-Commercial Energy Sales	(9,477,248)	(9,463,331)
	4025-Street Lighting Energy Sales	(243,678)	(242,949)
	4030-Sentinel Lighting Energy Sales	(978)	(978)
	4035-General Energy Sales	(4,173,134)	(4,167,050)
	4050-Revenue Adjustment		
	4055-Energy Sales for Resale		
	4062-Billed WMS	(2,902,710)	(2,898,410)
	4066-Billed NW	(1,994,897)	(1,991,951)
	4068-Billed CN	(2,404,377)	(2,400,826)
	4075-Billed-LV	(733,477)	(253,892)
	TOTAL	(\$33,551,217)	(\$33,023,042)
3350-Power Supply Expenses	4705-Power Purchased	25,515,756	25,477,962
	4708-Charges-WMS	2,902,710	2,898,410
	4710-Cost of Power Adjustments		
	4714-Charges-NW	1,994,897	1,991,951
	4716-Charges-CN	2,404,377	2,400,826
	4730-Rural Rate Assistance Expense		
	4750-Charges-LV	733,477	253,892
	TOTAL	\$33,551,217	\$33,023,042

The cost of power projections are based on projected consumption normalized for weather and having taken into account projected increases in customers as outlined in Exhibit 3, Tab 2

Reconciliation between Financial Statements and Financial Results Filed

The following differences between the Applicant's previously filed Record-Keeping Requirements ("RRR") filing, for the year ended December 31, 2006, and this application are as follows:

	COS Application	RRR Filing (Dec 31, 2006)	Difference	Reason
1508 – Other Regulatory Assets	238,653	226,993	11,660	To accrue for carrying charges that had not been previously accrued
1518 – RCVA Retail	(23,600)	(23,104)	(496)	To accrue for carrying charges that had not been previously accrued
1525 – Misc Deferred Debits	0	(33,940)	33,940	Adjustment from 2006 EDR Decision that had not been transferred to 4380
1548 – RCVASTR	54,105	52,092	2,013	To accrue for carrying charges that had not been previously accrued
1835 – OH Conductors and Devices	6,734,937	7,694,951	(960,014)	Reallocate accumulated amounts that should have been recorded in accounts 1845 and 1850
1845 – UG Conductors and Devices	5,563,155	4,252,638	1,310,517	Accumulated amounts reallocated that were improperly allocated to account 1835
1850 – Line Transformers	5,896,988	6,247,491	(350,503)	Accumulated amounts reallocated that were improperly allocated to account 1835
2105 – Acc'm Amtz'n on Utility Owned Equipment (PP&E)	(7,158,250)	(7,248,844)	90,594	Recalculation of amortization to take into account the ½ year rule
2205 – Accounts Payable	(4,504,489)	(4,504,481)	(8)	To balance trial balance
3045 – Unappropriated Retained Earnings	(3,579,835)	(3,533,144)	(46,691)	Effect of recalculation of amortization for 2005 to take into account the ½ year rule
3046 – Balance Transferred from Income	(1,624,229)	(1,533,213)	(91,016)	Total of all adjustments for accounts 4380, 4405 and 5705
4220 – Other Electric Revenue	(9,834)	(161,762)	151,928	Service Revenues allocated to account 4235
4235 – Misc Service Revenues	(159,654)	(7,726)	(151,928)	Service Revenues allocated from account 4220
4380 – Expenses of Non-Utility Operations	52,194	84,134	(33,940)	Adjustment from account 1525 above
4405 – Interest and Dividend Income	(376,499)	(363,322)	(13,177)	Adjustment from 1508, 1518 & 1548 above
5705 – Amortization Expense	1,317,175	1,361,074	(43,899)	Recalculation of amortization to take into account the ½ year rule

1 The following differences between the Applicant's previously filed Record-Keeping
2 Requirements ("RRR") filing, for the year ended December 31, 2007, and this application are as
3 follows:
4

	COS Application	RRR Filing (Dec 31, 2007)	Difference	Reason
1508 – Other Regulatory Assets	253,509	230,196	23,313	To accrue for carrying charges that had not been previously accrued (\$11,653 in 2007)
1518 – RCVA Retail	(47,324)	(45,207)	(2,117)	To accrue for carrying charges that had not been previously accrued (\$1,621 in 2007)
1525 – Misc Deferred Debits	0	(33,940)	33,940	Adjustment from 2006 EDR Decision that had not been transferred to 4380
1548 – RCVASTR	82,229	77,234	4,995	To accrue for carrying charges that had not been previously accrued (\$2,982 in 2007)
1835 – OH Conductors and Devices	7,357,202	8,559,245	(1,202,043)	Reallocate accumulated amounts that should have been recorded in accounts 1845 and 1850
1845 – UG Conductors and Devices	6,258,562	4,706,017	1,552,546	Accumulated amounts reallocated that were improperly allocated to account 1835
1850 – Line Transformers	6,521,923	6,872,425	(350,503)	Accumulated amounts reallocated that were improperly allocated to account 1835
2105 – Acc'm Amtz'n on Utility Owned Equipment (PP&E)	(8,591,890)	(8,811,337)	219,447	Recalculation of amortization to take into account the ½ year rule and recalculation of amortization of building at 2% as opposed to 4%
2205 – Accounts Payable	(4,124,233)	(4,124,226)	(7)	To balance trial balance
3045 – Unappropriated Retained Earnings	(5,204,064)	(5,066,357)	(137,707)	Effect changes in net income for 2005 and 2006 as detailed above
3046 – Balance Transferred from Income	(1,096,931)	(955,066)	(141,865)	Total of all adjustments for accounts 4405 and 5705
4220 – Other Electric Revenue	0	(286,908)	286,908	Service Revenues allocated to account 4235
4235 – Misc Service Revenues	(290,965)	(4,057)	(286,908)	Service Revenues allocated from account 4220
4405 – Interest and Dividend Income	(265,276)	(252,262)	(13,014)	Adjustment from 1508, 1518 & 1548 above
5705 – Amortization Expense	1,433,640	1,562,492	(128,852)	Recalculation of amortization to take into account the ½ year rule

5

Proposed Accounting Treatment for long lived assets

The following information relates to the accounting treatment of long lived assets. Long-lived assets include property, plant and equipment and intangibles that are subject to amortization.

Property, plant and equipment are stated at cost and are removed from the accounts at the end of their estimated average service lives, except in those instances where specific identification allows their removal at retirement or disposition. Gains or losses at retirement or disposition of such assets are credited or charged to "Other income" in the Statement of Income. In the event that facts and circumstances indicate that property, plant and equipment may be impaired, an evaluation of recoverability is performed. For purposes of such an evaluation, the estimated future discounted cash flows associated with the asset are compared to the carrying amount of the asset to determine if a write-down is required.

The impairment loss is measured as the amount by which the carrying amount of the assets exceeds its fair value.

Compliance with the Uniform System of Accounts

WPI is in compliance with the OEB's Uniform System of Accounts for electricity distributors.

Accounting Orders

Where applicable, WPI is in compliance with the OEB's related accounting letters and orders.



Westario Power Holdings Inc.

385 Queen Street

Kincardine, Ontario N2Z 2R4

Tel: (519) 396-3471 Fax: (519) 396-7605

Our Mission

Westario Power is an energy distribution and services corporation with a mission to build a quality, customer focused organization.

Our companies will provide safe, reliable cost-effective services and products achieving sustainable growth while respecting the community and the environment.

Our Vision

We are dedicated to creating superior value for our customers and shareholders, and a safe, rewarding work environment for our employees.

We will grow our business through innovation and creative leadership, based on sound fiscal management and business practices.

Board of Directors

Westario Power Holdings Inc. and Westario Power Services Inc.

Mark Kraemer	-	Chair	David Anderson	-	Director
Charles Bagnato	-	Director	Bill Daley	-	Director
William Goetz	-	Director	Bob Jameson	-	Director
Lynn Lowry	-	Director	Bill Roseborough	-	Director
Ken Saxton	-	Director			

Westario Power Inc.

Mark Kraemer	-	Chair	Patricia Bell	-	Vice Chair
Bill Daley	-	Director			

Management

Guy Cluff	-	President/CEO
Lisa Milne	-	Controller
Janice Hallahan	-	Customer Service Manager
Patrick Protomanni	-	System Reliability Manager
Verna Hodgins	-	Executive Assistant

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Message from the Chair

Mark Kraemer



Westario Power passed some very significant milestones in 2007.

The Board of Directors continued investment in the distribution system, spending \$3 million in new additions and upgrades to the distribution system.

Another clean audit in 2007 showed combined net income of \$902,713 on sales of \$40.5 million, making 2007 the fifth continuous year of dividends for the company's shareholders. In total, shareholders have received dividends of \$1.98 million since 2003.

In this new age of electricity provision in Ontario, the role of companies like Westario Power, once a public utility, now a private company; once regulated, now once again regulated; is not always clear. The industry is dynamic to say the least, and the journey so far has usually been on rough waters as new and changed regulations and circumstances continue to demand quick response from the utility companies.

When a customer flicks a switch, a factory full of machinery still comes to life, the room light still comes on, the stove still heats up, the furnace fan distributes warm air throughout the house. And life seems perfectly normal! Same as it ever was.

The Board well realizes that achieving and maintaining such standards has taken the efforts of many people. And its done, seamlessly and invisibly to our customers which is the way it should be. And its the power of Westario staff that has done it.

In 2007, Westario staff, all of them, finally moved in together in our own building in Walkerton, central to our area of operations, providing the company with the space they need to continue to work comfortably for many decades to come.

At the helm, since November 2000 when Westario came into being, the blending of eight small public utilities serving fifteen communities, has been our first and only President and CEO, Guy Cluff.

Guy Cluff announced his retirement effective July 31, 2008. It is wonderful that Guy can move onto to this new phase of his life, enjoying his grandchildren and pursuing his woodworking. We are however going to miss Guy's quiet professionalism, his integrity and his desire to simply make Westario the best LDC in the province. As our only CEO to date, he has guided us through those turbulent times and helped us emerge as a customer focused organization with a solid financial base.



On behalf of the Board and staff I would like to thank Guy for his years of dedicated service and wish him many years of health and happiness in his retirement.

November 27, 2007, was the official opening of the new office and storage yard of Westario Power, located in Walkerton. The new building brought together all of the Westario Power staff, in one location for the first time. Among the many community representatives and guests present were the Board of Directors- L to R - Lynn Lowry, Ken Saxton, Bill Daley, Mark Kraemer, Charles Bagnato, Bill Roseborough, Bob Jameson and Bill Goetz.- photo by Robert Baillargeon

Message from the President and CEO

Guy Cluff



Operating in an environment of rapidly evolving regulation, provincial initiatives directed at Local Distribution Companies (LDCs) to promote political policy, and increasing customer focus on rates and service quality, today's LDCs are engaged in a delicate balance of customer expectations, shareholder needs and public policy. Westario Power and more importantly, its people, have met these challenges head-on with enthusiasm, adaptability and commitment.

Customer satisfaction increased 2% in 2007 with 81% of customers surveyed indicating that they were satisfied or very satisfied with the Company's overall service.

Shareholder dividends continued for the fifth consecutive year. At the same time, the Company's assets have more than doubled in value from \$18 million in 2000, to nearly \$42 million in 2007.

Westario Power spent more than \$650 thousand during 2007 on conservation and demand management programs that resulted in energy savings for our customers of over **10 billion watt-hours**.

2007 also saw the on-budget completion of the Company's new administration and operations centre in Walkerton. In addition to the financial benefits, the operational and interrelationship advantages of locating all staff at one physical location continue to be realized.

With the unanimous endorsement of all shareholders, the Westario Power group of companies applied to the Ontario Energy Board (OEB) for approval to merge into one company. Approval was received in November 2007 with the requirement to complete the merger within 18 months. I am pleased to report that the merger was completed on January 1, 2008, including the combining of the three companies' computer systems. Staff are to be complimented on the seamless transition of the merger.

The Future

The regulatory environment continues to change as the OEB moves decisively towards performance based regulation. This trend places more onus on LDCs to justify past and future spending – on a project by project basis. The amount of detail required is extensive. Westario Power started planning for this process in the first quarter of 2008 for its 2009 rate application. The work, however, is expected to be well worth the effort as the process allows for bringing the asset base, upon which rates are determined, from 2004 levels to the average of 2008/2009. This will add an estimated \$7 million to Westario Power's rate base thereby increasing the return on equity available to the Company and shareholders.

As reported last year, the provincial government announced a *Transfer Tax Holiday* until October 17, 2008, eliminating the 33 per cent transfer tax payable by a municipality or municipally electric utility that sells or transfers electricity assets to another municipal entity. Keeping with past philosophy, Westario Power will build on traditional utility core business activities and explore new merger/partnership opportunities that benefit our customers and shareholders. A number of opportunities are being actively pursued.

In November, I advised the Board that I will be retiring at the end of July 2008. July 1, 2008 will mark my thirty-fifth year in the utility business. My career in this industry has been tremendously rewarding, none more so than that with Westario Power. Integrating eight former municipal entities, serving fifteen communities, at a time when Ontario's electricity industry was undergoing fundamental changes in every aspect, has been an enjoyable challenge - despite some of the frustrations along the way.

Together – the Board, management and employees – have an outstanding track record in meeting these challenges. I have every expectation that Westario Power will continue to be an example of how the collaborative efforts of all can lead to problem solving, improvement of, and innovation, in this business and industry. I am proud of our collective accomplishments since the creation of Westario Power.

I truly appreciate the confidence that the Board and shareholders have shown in me during my time with Westario Power. I also want to thank the Management Team and staff for their efforts, commitment and support, without which Westario Power's successes would not have been possible.



Westario Today

Introduction and Corporate Structure

The municipal shareholders of Brockton, Hanover, Huron-Kinloss, Kincardine, Minto, Saugeen Shores, South Bruce, North Huron and its private equity owner, Fortis Ontario Inc., own Westario Power Holdings Inc. and its subsidiaries. The corporation is a for-profit private business entity incorporated on November 1, 2000 pursuant to the Ontario Business Corporations Act. The corporation is comprised of the following corporate entities:

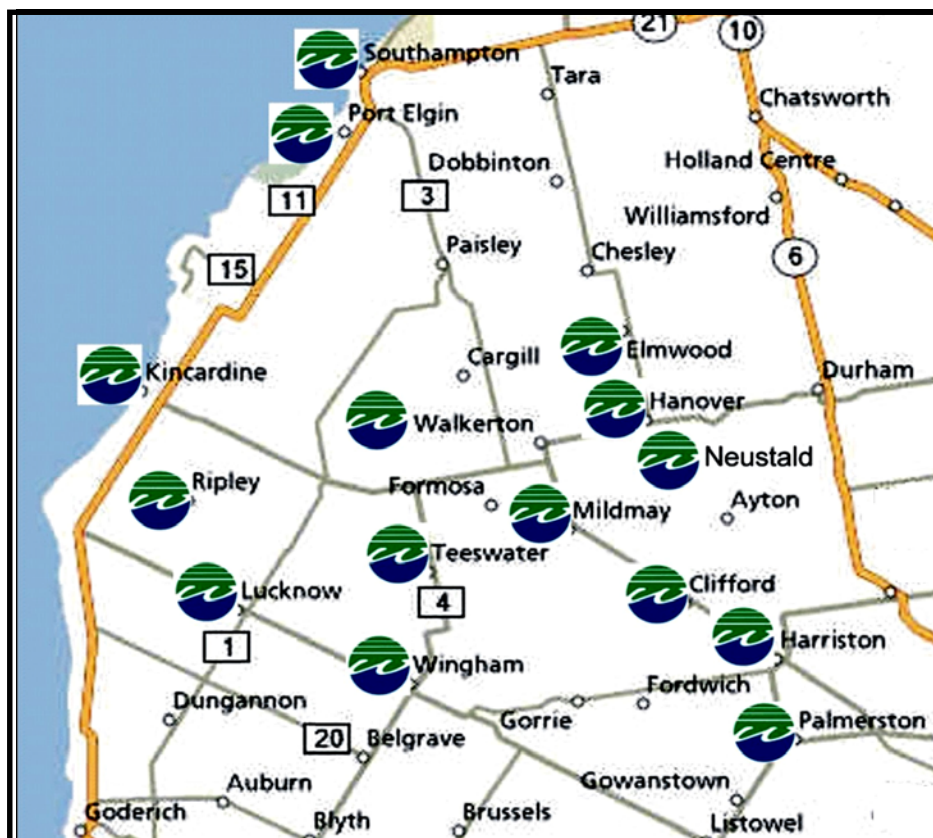
Westario Power Holdings Inc.
Westario Power Inc.
Westario Power Services Inc.

Holding Company
Local Distribution Company
Services Company

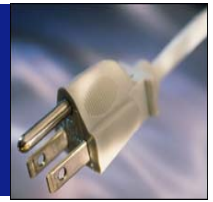
The Company's primary business is the oversight of its regulated affiliate - Westario Power Inc. Westario Power Inc. is a regulated Local Distribution Company (LDC) that owns and operates electricity distribution infrastructure.

The company's service territory is an amalgamation of 15 communities distributed over four counties serving nearly 22,000 consumers.

The combined demand for electricity in these communities is expected to grow at an average rate of 1% per year over the period 2006-2010.



Description of Our Business



Westario Power Holdings

The role of Westario Power Holdings is to:

- assess the strategic value of the business activities of each of its subsidiaries;
- evaluate the performance of each of these subsidiaries;
- provide strategic direction to our subsidiaries on matters of financing, risk mitigation, taxation, laws and regulations, public affairs, human resources, and business development;
- and ensure that our subsidiary companies abide by OEB regulations and codes applicable to them.

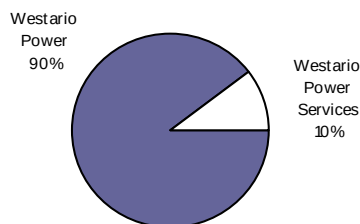
Section 73 of the *Ontario Energy Board Act, 1998*, restricts our business activities generally to:

- (a) Meter reading services;
- (b) Billing and Collection services;
- (c) Tree trimming services for the purpose of line maintenance;
- (d) Repair and Maintenance for the distribution lines and facilities;
- (e) Construction of distribution lines and facilities;
- (f) General administrative support services; and
- (g) Telecommunications services for electricity distribution (e.g. SCADA).

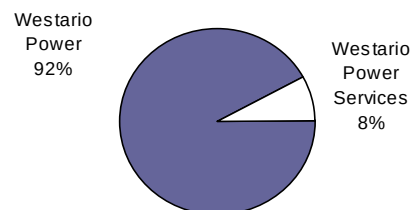
The restrictions imposed by section 73 applies to Westario Power Holdings and its affiliates as long as more than 50 percent of the voting rights of our LDC are municipally owned. The OEB's *Affiliate Relationships Code* prevents us from subsidizing competitive or non-monopoly activities with electricity distribution revenues. The establishment of our business in separate operating subsidiaries is designed to ensure compliance with this Code and other requirements of the *Electricity Act, 1998*, the OEB and its various codes.

The charts below provide a percentage breakdown of our capital assets and revenues by business segment as at December 31, 2007.

**Assets by Affiliate
2007**



**Revenue by Affiliate
2007**





Strategic Priorities

Our strategic priorities are to:

- create superior value for our customers and shareholders, and a safe and rewarding work environment for our employees;
- build shareholder value by growing our business through innovation and creative leadership, based on sound fiscal management and business practices;
- provide safe, reliable cost-effective services and products achieving sustainable growth while respecting the community and the environment; and
- improve system reliability, increase customer satisfaction and enhance our reputation.

We have made significant strides in recent years to refurbish the electricity distribution infrastructure needs in the communities we serve. However, there will always remain requirements to improve and expand our assets. Cash flow is expected to fund more than 50% to 75% of the cost of these investments, the balance by debt. Our businesses are capital-intensive, requiring a long-term approach to financing capital assets.

Key Performance Drivers and Financial Implications

The two businesses operated by Westario Power Holdings use a number of key performance drivers to track the progress of their operations.

The performance measures used concentrate on human resources, financial performance, service quality standards, innovation and execution of major projects. The company's measures for targeting and monitoring financial performance are net income, planned capital expenditures on reliability, and planned capital expenditures on general capital. The metrics for tracking and monitoring performance for customer service are established by the OEB as part of its service quality indicators. These standards include:

- timeliness in connecting new customers;
- telephone accessibility for customer enquiries;
- response times to customer written enquiries;
- response times to emergencies; and
- achieving targeted levels of system reliability for the duration and frequency of outages.

Westario Power – Our Core Business

Westario Power serves nearly 22,000 electricity consumer accounts. Almost 90% of our consolidated assets and about 92% of our consolidated revenues relate to Westario Power.

Business Operations

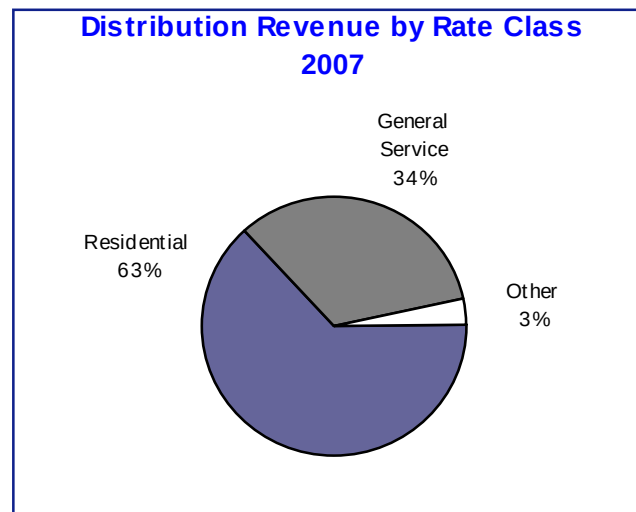
Westario Power's business involves buying, transforming and distributing electricity. It buys the electricity from the IESO at wholesale market rates. The electricity is typically received at transformer stations owned and maintained by Hydro One. Westario Power then



transforms that electricity to “primary distribution voltages” at its own substations. From there, power is delivered to customers using a network of overhead lines and underground cable.

Westario Power had total assets of approximately \$39.6 million as at December 31, 2007, including about \$25.6 million of capital assets.

The company’s electricity sales over the twelve months ended December 31, 2007 totalled 447,022,784 kWh. Westario Power’s customers are categorized as residential, general service (commercial and industrial) and street lighting. Eighty-seven percent of the LDC’s customers fall into the residential category and 12% are general service.



The strategically most important aspects of Westario Power’s business are:

- managing within a regulatory regime;
- system reliability;
- timely and accurate billing and collection;
- consistently earning a full regulated rate of return;
- maximizing the efficiency of the workforce;
- meeting or exceeding OEB customer service targets; and
- continuing with active safety and environmental stewardship programs.

Maintaining an electrical distribution system poses a variety of risks centered on the “hands-on” work that must be done every day. The safety of our people is and must be a priority put into practice daily. Our operations people work under conditions that can pose a hazard if all forms of energy (electrical, kinetic, thermal, etc.) are not properly controlled. Mitigation of these hazards and risks is accomplished through the implementation and continuous improvement of our health and safety management system.

This system includes comprehensive training programs; detailed policies, procedures and safe work practices; inspection programs and other systems to detect deficiencies, identify remedial actions and track them to completion.

Competition

As an LDC, Westario Power does not currently face competition from other LDCs or electricity retailers.

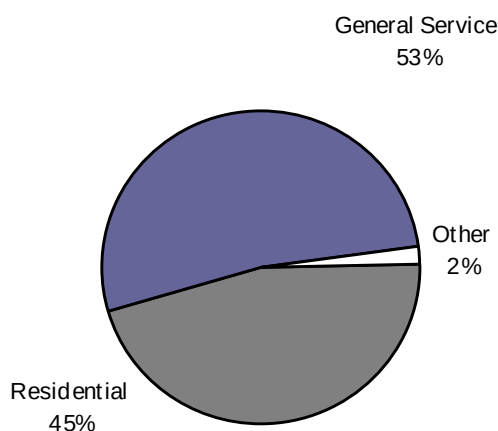
The *Ontario Energy Board Act* and the *Electricity Act, 1998* established a regime to permit independent retailers to sign up customers and use a LDC's distribution network and billing system for the sale of electricity to consumers who enrol with the retailers. Detailed rules governing the relationship between LDCs and retailers are prescribed in the OEB's *Retail Settlement Code* and the *Standard Supply Service Code*. Approximately 13% of Westario Power's customers purchase their electricity through an electricity retailer. Westario Power provides distribution services to these customers.

Operating Data

Westario Power Holdings Inc. - Consolidated Financial Results Year Ended December 31 (audited)

	2007	2006	2005
Total Revenues	\$40,472,517	\$39,895,958	\$40,671,794
Net Earnings Before Tax	\$1,404,797	\$1,937,162	\$1,418,080
Net Earnings	\$902,713	\$1,297,488	\$916,661
Retained Earnings	\$2,961,256	\$2,577,538	\$1,646,714
Balance Sheet Items			
Total Assets	\$41,830,492	\$40,452,889	\$38,762,015
Shareholder's Equity	\$21,254,516	\$20,846,709	\$19,915,882

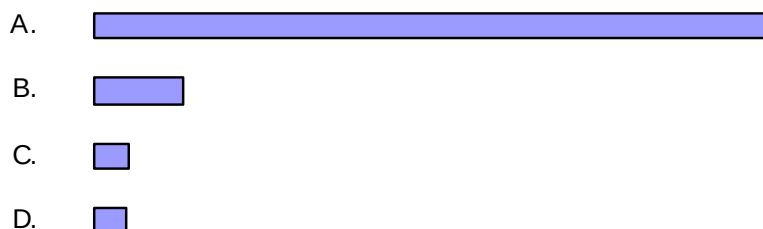
Total Revenue by Rate Class 2007



Revenue - Revenue is earned from electricity distribution and related services. Consolidated revenue increased \$576,559. Distribution sales decreased \$139 thousand.

Expenses - The largest component of total expenses is the cost of power purchased from the provincial government, which fluctuates based on the commodity price for electricity. Purchased power increased by \$623,666.

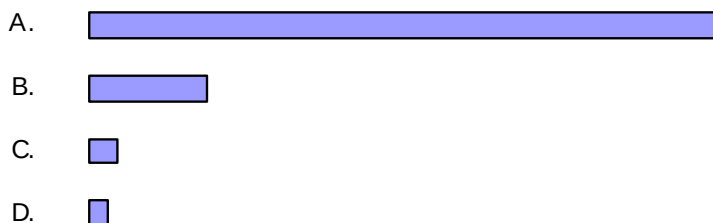
**2007 Expenses
(audited)**



A. Purchased power	\$ 31,693,323
B. Operating, maintenance and administration	\$ 4,197,248
C. Amortization of capital and intangible assets	\$ 1,650,193
D. Interest, taxes and rent	\$ 1,526,956

Net earnings - Net earnings from consolidated operations increased by approximately \$380 thousand from \$916 thousand to \$1.3 million primarily due to lower interest and rental expenses.

**2006 Expenses
(audited)**



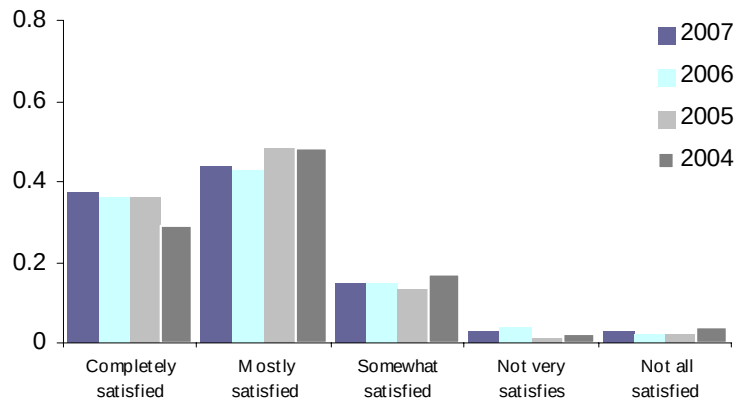
A. Purchased power	\$ 31,069,657
B. Operating, maintenance and administration	\$ 5,814,661
C. Amortization of capital and intangible assets	\$ 1,436,328
D. Interest, taxes and rent	\$ 933,068



Customer Service Division

Janice Hallahan Manager, Customer Service

Overall Satisfaction With Quality of Service



Results from the November 2007 Customer Satisfaction Survey suggest there continues to be little change year-over-year and that the majority of customers continue to be satisfied with the overall quality of service provided by the Company. The results for 2007 were an improvement over 2006, of 2 percent to 81 percent – returning our score to over 80 percent satisfaction. Compared to other utility providers, namely local telephone and satellite television providers, the perceived value of service received from Westario Power Inc. is considered to be of equal or greater value than services provided by these other utilities.

Westario Power Inc.'s service delivery process continues to be well received by customers, particularly in terms of providing **reliable and safe delivery** of electricity to local homes and businesses. Other aspects of the process that continue to receive positive ratings by the majority of customers include the Company's ability to **restore power in a timely manner** in the event of power outages and providing **timely and accurate customer bills**.

In terms of Westario Power Inc.'s communication efforts, the Company's performance on **keeping customers informed about changes to the electricity industry** has seen a

Customer Satisfaction Survey

Starting in 2003, Westario Power, in partnership with FortisOntario, commissioned Corporate Research Associates Inc. (CRA) to conduct a Customer Satisfaction Study among Westario Power customers. The primary objective of these studies are to provide a quantitative measurement of customer perceptions and attitudes. 250 customers were contacted by telephone with a survey length of 7 minutes. Specifically, the study seeks to:

- Determine overall satisfaction with the quality of service provided by Westario Power;
- Provide a comparison of the perceived value obtained from Westario Power relative to other utility providers;
- Determine overall satisfaction with the reliability of the service provided; and
- Assess customers' satisfaction with the quality of customer service.

slight decrease this year after an increase in the previous year. Customers' ratings generally remain positive in terms of **providing timely and reliable information** during power outages **and responding to customer questions or concerns**.

Overall, the majority of customers continue to hold a positive attitude towards Westario Power Inc.'s **quality of customer service**. As in previous years, customers who are completely or mostly satisfied with the Company's quality of service are more apt to provide a rating of excellent or good in terms of the quality of customer service.

Although recall of "Conservation Tip" advertising remains minimal, customers who heard the tips continue to feel that they are helpful in reducing household energy consumption.

I am pleased to report that the meter reading schedule has been falling within the targeted +/- 3 billing dates for the first month of the year and the last two months. Inclement weather/road closures prevented the CCS Division from meeting their +/- 3 billing dates schedule in the month of February and March.

Information from field staff is ongoing to improve the effectiveness and efficiencies within the SAP billing software.

The billing department, within the CCS Division, has met their performance measure of 99.95% billing accuracy every month in 2007.

The Call Centre has exceeded their performance measure of 65% every month in 2007

Corporate Website

We successfully launched our new corporate website on December 17, 2007. Items of Interest, Corporate Mission Statement, Conditions of Service, How to Calculate A Bill Simulation, Rates, electronic document submissions, updated Links, Safety & Conservation Tips, etc. can all be found on the website now. If you have not viewed the website recently, I encourage you to. Floating-Point Communications of Belleville has been commended on a job well done.

Collection/Field Activity

Dunning/collection operations are very busy. A dunning/collection run is executed weekly with about 750 – 1000 reminder notices/disconnection notices printed. Westario Power disconnects on average about 8 premises per day. Since October 2003, there are still 42 premises disconnected. In the summer of 2005, we instituted the measure of hand delivering disconnection notices. By placing the notice in the hands of the contract account holder or taping it to the door of the owner of the premise, Westario Power call centre/collections personnel receive prompt responses from the account holder to make payments or arrangements towards outstanding balances.

The CCS Division is aggressively pursuing outstanding hydro accounts with the Owen Sound Credit Bureau. To date, Westario Power has recovered approximately \$635,000 in Aged Accounts Receivables. Westario Power has launched approximately 180 Permission to Sue with the Small Claims Courts within the 4 counties we service totaling \$307,000 (judgement received, execution against land, examinations, claims and garnishments). The Owen Sound Credit Bureau is confident in collecting a large portion of the Aged Accounts Receivable in the year 2008. The Credit Bureau's recovery rate on Westario accounts to date is 51.26%. Their goal is to achieve a 60% recovery rate in 2008.

Changes to the Electricity line of your bill

The Ontario Energy Board (OEB) has not changed the electricity prices, effective May 1, 2008 for Regulated Price Plan (RPP) consumers who have their electricity supplied by a utility.

- ~ 5.0 cents per kilowatt hour (kWh) for energy use up to 600 kWh per month
- ~ 5.9 cents per kWh above that threshold

The price threshold for residential consumers will change twice a year April and November. The threshold will be 1,000 kWh per month during a winter season (November 1 to April 30) and 600 kWh per month during a summer season (May 1 to October 31). This means consumers will be able to use more hours of electricity at the lower price in the winter when many people need more electricity for light, indoor activities and heating.

Non-residential consumers who are eligible for the price plan will pay 5.0 cents per kWh for the first 750 kWh they use per month (pro-rated by # of days billed), and 5.9 cents per kWh they use over this threshold. The price threshold for non-residential consumers will remain at 750 kWh per month for all seasons.

Share The Warmth

Share The Warmth is a registered non-for-profit charity that purchases heat and energy assistance on behalf of low-income families, seniors, disabled and terminally ill persons across the Province of Ontario.

Westario Power launched the 2007/2008 heating season with Share The Warmth in December 2007. This partnership is necessary to promote awareness of the program in order to help increase donations. A donation as small as \$18 provides warmth for a household for two days. The 2007/2008 heating season assisted 12 families with energy assistance proceeds of approximately \$1,850.

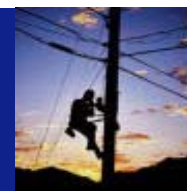


The Walkerton Rotary Club provided a barbeque lunch and the Walkerton Clown thrilled a lot of children, while raising money for the Walkerton Medical clinic at the opening of the new Westario building in Walkerton. -- photos by Robert Baillargeon



System Reliability Division

Patrick Protomanni, P. Eng. Manager, System Reliability



Health and Safety

Westario Power's corporate Joint Health & Safety Committee is composed of two management members, and two bargaining unit members. The conduct of the committee is governed by the laws of Ontario and the Board of Director's commitment to providing a safety and health workplace. The Board of Directors has provided direction in the form of a Board approved policy defining the administrative responsibilities of the Committee. The Joint Health and Safety Committee met ten times in 2007.

The System Reliability (SR) Division holds regular safety meetings with its staff. The meetings are scheduled, generally, for the last week of the month, and are held every month except December.

Staff participation is not only encouraged, but evident by the number of union members who actively participate in open discussion and make suggestions for work practice development and betterment.

A standing agenda item at all SR safety meeting is a review of select work practices and safety procedures. This ensures that all staff remains knowledgeable of the work practices and procedures, and that recommendation for improvement to practices and procedures are discussed in an open forum, and adopted where appropriate.

Lastly; there have occurred no lost time accidents at Westario Power in 2007.

Asset Management and System Planning

Asset management is a systematic process of maintaining, upgrading, and operating physical assets cost-effectively. It combines engineering principles with sound business practices and economic theory, and it provides tools to facilitate a more organized, logical approach to decision-making for distribution system assets.

In 2007 Westario Power began the task of collecting field data of its assets. The distribution system records were found to be incomplete, and management decision making was hampered by a need for good field information.

The data collection project involves collection of all overhead and underground field data, where practicable, for incorporation into our asset records. This task is a long term project whose purpose is to build an asset database. In addition to providing the data for the asset management records, the documents are also an inspection record of the distribution plant.

This database becomes a solid foundation from which to monitor the distribution system and optimize the preservation, upgrading, and timely replacement of distribution assets.

Westario Power Distributing System Statistics:

Winter Peak	90,205.23 kW
Summer Peak	73,472.11 kW
Average Peak Demand	73,257.94 kW
Number of Distribution Substations	27
Number of Distribution Feeders	89
Number of Distribution Transformers	2989
Overhead Lines	309.9 km
Underground Lines	126.2 km

Operating, Maintaining and Expanding the System

Every year Westario Power invests in infrastructure expansions and replacements, performs maintenance, and carries out various operations on the distribution system.

Capital Works

In 2007, 24 capital works projects were planned. Most capital works are multi-year projects aimed at replacement of aging infrastructure. In Kincardine, Port Elgin and Harriston, end-of-life cables and transformers were replaced. Existing overhead pole lines were rebuilt in Kincardine, and a feeder tie in Walkerton was reinforced.

Capital works for system improvements were also undertaken. In these projects, existing non-standard equipment was replaced upgrading distribution system reliability. These investments pay off by reducing long-term system maintenance. Aged and end-of-life wood poles were replaced in a variety of locations, and porcelain insulators were replaced with polymeric insulators in Hanover, Walkerton, Kincardine, and Palmerston. In Harriston, the distribution system neutral was extended to improve system safety.

Additionally, capital dollars were spent to install a new high voltage primary metering unit for the Town of Walkerton as the existing Hydro One-owned installation was decommissioned.

A spare substation transformer was refurbished in 2007 and returned to Westario Power's Operations Center. This substation transformer was originally in service in Palmerston. In 2006 the substation was removed from service when a tank leak was detected. The substation was completely torn down and the core and coils (the heart of the substation transformer) were found to be in excellent condition. A new, improved, water-tight tank was fabricated, and the substation was subjected to a battery of tests before being returned to our Yards for storage.

Maintenance

Annually, Westario Power undertakes tree trimming and line clearing operations. As in the past, about 12 weeks of dedicated effort were expended and our objectives for 2007 were met. Nevertheless, tree trimming and line clearing is an on-going task, and through the year additional tree clearing jobs were initiated when distributions system reliability and public safety issues were identified.

Also, planned substation maintenance work is undertaken every year. Substations represent one of our most valuable assets. Every year seven substations are removed from service and a full maintenance is performed to ensure the long-term performance of these valuable assets. In addition, regular oil samples are drawn to verify substation transformer health, and identify problems before severe damage can occur.

Repairs and Operations

Westario Power receives numerous requests for service changes and new electrical connections. In 2007 Westario Power connected 291 new "low voltage" services. This number represents an increase over both the 2006 connections and the three-year average.

Projects Completed in 2007

2007 was a year of upgrading and replacing Westario Power's plant and infrastructure. The new operations center in Walkerton was not the only project. Old poles, pole lines, cables, transformers and even insulators and more are gone across Westario territory.

There was a large quantity of old and defective poles many likely standing by virtue of the conductors holding them up. Westario replaced those poles and equipment in **Lucknow, Wingham, Teeswater and Ripley**.

Defective porcelain insulators were replaced in **Hanover, Walkerton, Palmerston and Kincardine**. A long time industry standard, now a popular collectors item, porcelain insulators, have been a cause for many system failures. These insulators are known to break-off the base, where the porcelain is cemented into the steel fitting. The age and type of assembly used contribute to the high rate of failure. This is a known province wide problem. When these insulators break, the energized conductors contact adjacent phases or the poles and cause wide spread system outages. The new style polymeric insulators are more robust, lightweight, and more durable than the porcelain insulators.

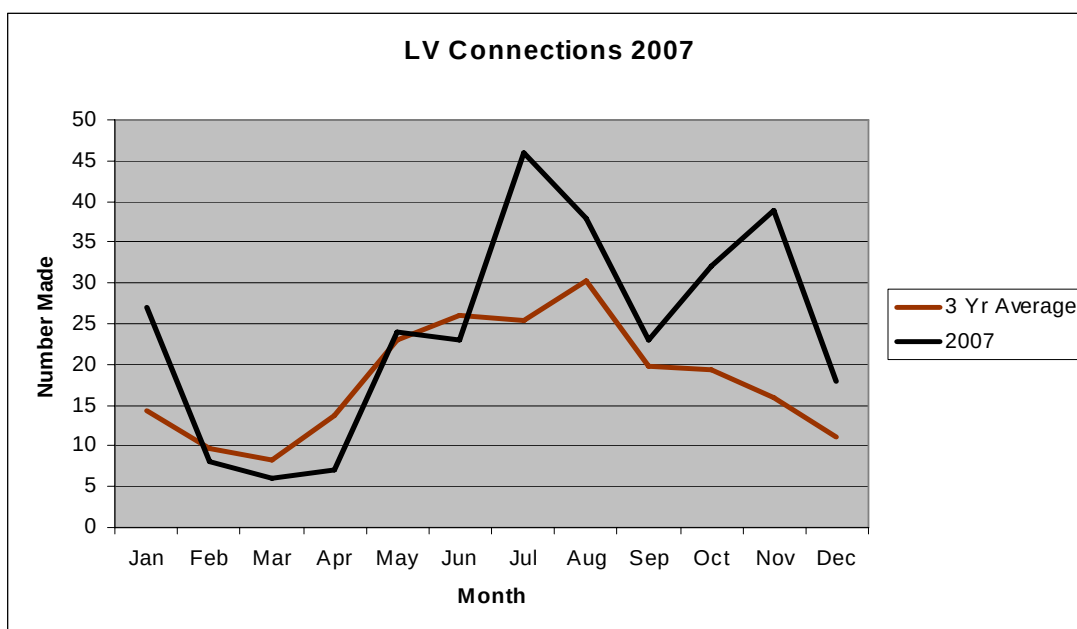
In **Kincardine, Port Elgin, and Harriston**, end-of-life cables and transformers were replaced. This infrastructure is failing, as the life expectancy of the original cables had a life span of about 20 years and most of these cables were over 30 years old, and direct-buried. The Port Elgin project is part 3 of 10, while the Kincardine project was part two of five. The Harriston project was a one-of and no additional work of this nature needs to be done there.

In addition to this work in **Harriston**, Westario Power installed a new neutral tie on Elora Street. A plant inspection found a gap in the distribution system neutral on one feeder. The neutral is used to control voltages and establish ground potential. The second feeder into town had a full sized neutral and was supporting the entire town. If this neutral had been pulled down when a tree toppled, the result could have been wildly fluctuating voltages and present shock hazards to customers.

In **Walkerton**, the feeder on Peter Street was rebuilt to increase feeder capacity and provide a tie between two substations. This provides Westario Power with the ability to switch loads from one substation to another and improves system restoration in the event of an outage.

In **Kincardine**, Westario Power carried out rebuilds on Princes Street and on Saugeen Street. On Princes Street, the 44 kv feeder supplying the MS1 substation was rebuilt. The project was undertaken as the old poles were rather short, causing a clearance issue between the high voltage circuits. Further, porcelain insulators were replaced improving reliability of supply to the substation.

Also in **Kincardine**, the pole line on Saugeen Street was rebuilt. The poles were quite old and the primary conductor was undersized for the load in the area. This type of primary wire has been problematic in the past.

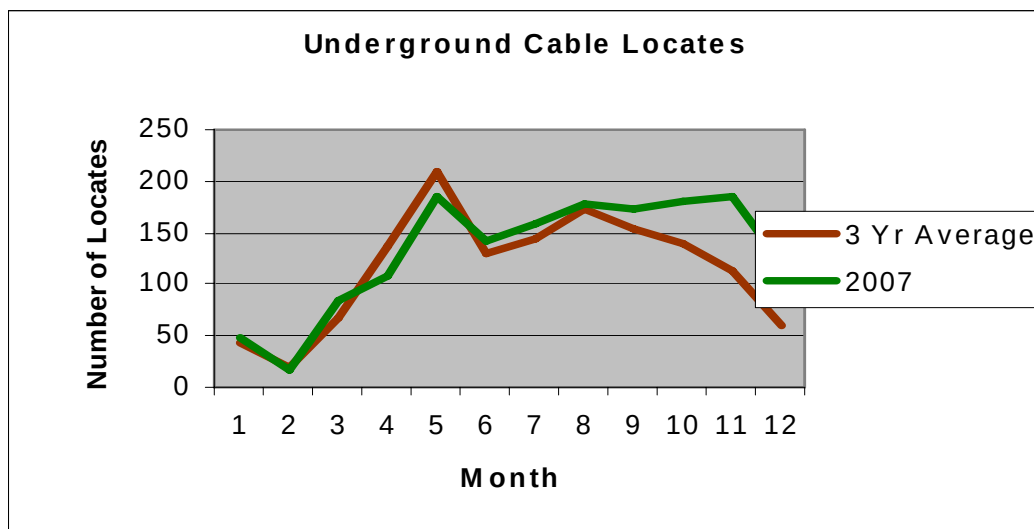


A regulated requirement of the Ontario Energy Board is to make these service connections within 5 business days, 90% of the time. In 2007 96.6% of these low voltage services were connected within the 5 business day window.

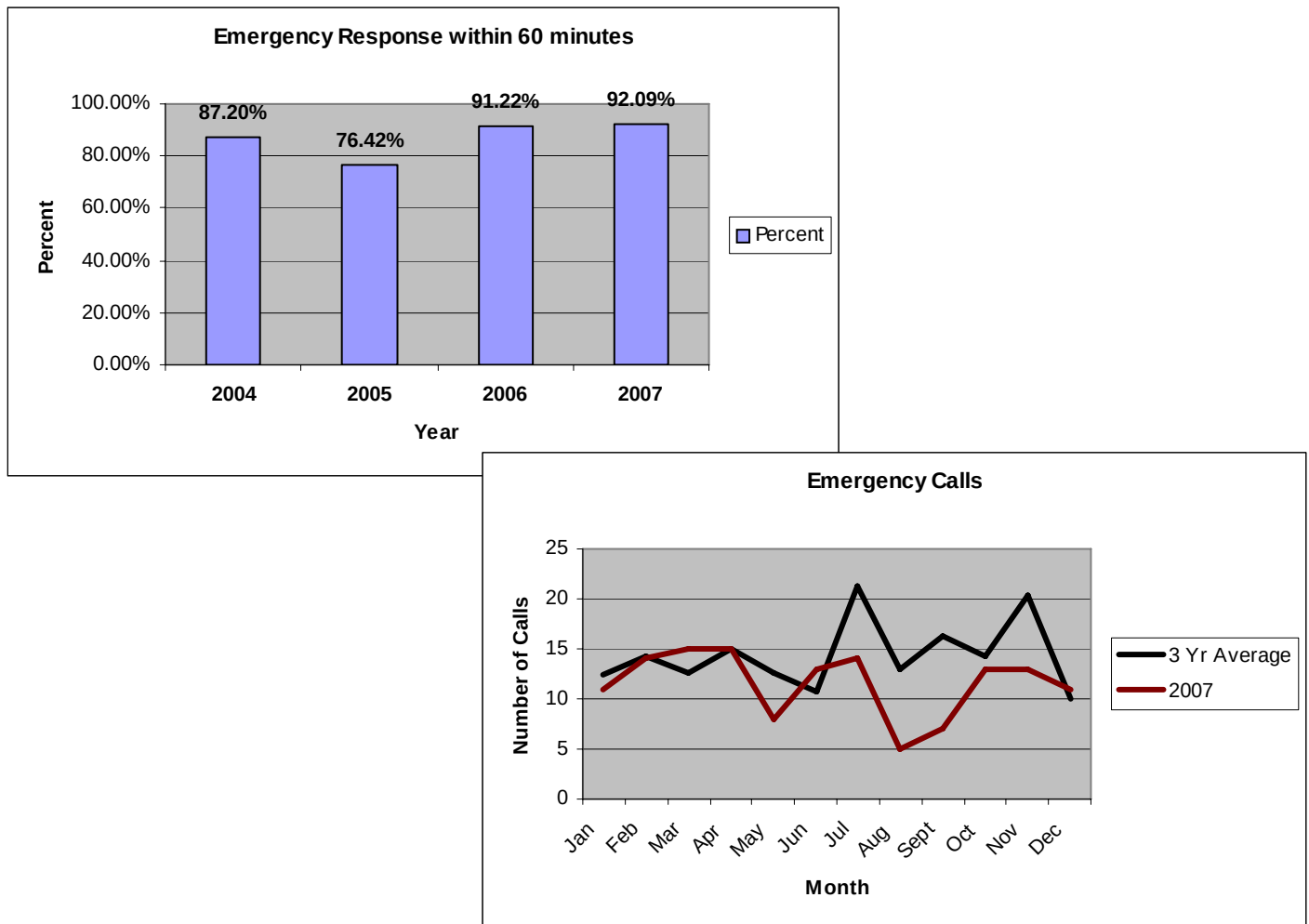
Any excavation work in Ontario requires the excavator to obtain underground locates to identify buried facilities prior to digging. Westario Power responded to 1578 requests for underground locates in 2007. Interestingly, the cyclic nature of excavation usually sees requests for underground locates peter-out after September. This was not the case in 2007, as requests for underground locates remained steady through the autumn, and did not subside until December.

As above, the Ontario Energy Board requirement is to fulfill the request for underground locates in 5 business days, 90% of the time. In 2007 Westario Power provided underground locates in 5 business days in 96% of the time.

Typical distribution system operations also include response to emergency no-power



calls, or line-down calls. In 2007, Westario Power responded to 139 emergency calls, and was on site in 60 minutes or less, 92% of the time. Westario Power's regulated requirement for emergency response is 90%. Yet another required target met.



Storm Events

In February 2007, and again in March 2007, Westario Power service territory was walloped with severe winter storms. The storm of February saw some scattered system damage and a few cases of loss of supply during the height of the storm. Heavy snowfalls and high winds hampered travel. Damage was dispersed but generally minor and was quickly managed.

The storm of March 2007, while shorter in duration had a much greater affect. Hydro One reported loss of entire pole-lines along the shore of Lake Huron. Freezing rains followed by gusty winds toppled 44 kV subtransmission circuits supplying Kincardine, Ripley and Lucknow, and Saugeen Shores. On Friday March 2nd, the Municipality of Kincardine initiated their emergency plan after the Town's feeders were toppled by the ice loads. Hydro One rushed work crews from across the province to the scene and was able to restore Kincardine by the end of day Friday by rerouting power from Wingham.

Saugeen Shores faired less well. Hydro One was able to restore power to both Port Elgin and Southampton by rerouting a feeder from Owen Sound. This, however, caused problems of its own, as the source station was some considerable distance away. Line

losses and extreme demand strained the feeder; supply was lost twice as the feeder tripped out due to loading.

By Sunday evening, Hydro One had succeeded in rebuilding one feeder to Saugeen Shores and, was able to switch Saugeen Shores over to the restored feeder.

While we weathered the usual spring, summer, and autumn storms, Westario Power saw no significant system damage from storm events.



Westario escaped winter damage.... but Hydro One had major losses and major recovery efforts! One in particular was the loss of a major pole line along Hiway 21 south of Kincardine



Smart Meters

The Ontario government has made a commitment to install a smart electricity meter in 800,000 homes and small businesses by 2007 and throughout Ontario by 2010. While holding promise for consumer demand management, the initiative entails risks and uncertainties for Westario Power.

In 2005, Westario Power participated in a proof-of-concept pilot project, along with the Ontario Utilities Smart Meter working group, and deployed about 125 smart meters in the Village of Mildmay. While that deployment was successful and the lessons learned were valuable, these meters are now considered old technology.

The Energy Conservation Responsibility Act, 2006, established the framework for the installation of Smart Metering in Ontario, including an entity that will oversee Ontario's Smart Metering communications systems and technologies. Under the legislation, Westario Power will own, install, operate and maintain the new meters.

The legislation gives the government flexibility to determine the best options for the governance, ownership and regulatory structures of the Smart Metering initiative as it goes forward.

Under the Provincial Legislation and Regulations, Westario Power cannot purchase smart meters until it is named in Regulations as approved by Provincial Cabinet. The Cabinet will not name any LDC in new Regulations until the next generation smart meters are approved by the Province. No new smart meters have been deployed in Westario Power territory in 2007.



The linemen demonstrate skill and safety at the Official Opening of the new building, November 27, 2007 - photo by Robert Baillargeon



Conservation and Demand Management Initiatives

Patrick Protomanni, P. Eng. Manager, System Reliability

In 2004, the Minister of Energy granted approval to all electricity distributors in Ontario to apply to the Ontario Energy Board for an increase in their 2005 rates by way of the third installment of their incremental market adjusted revenue requirement (“MARR”). This approval was conditional upon a commitment to reinvest in conservation and demand (CDM), an equivalent of that amount.

Consequently, in 2005 Westario Power brought forward, and the Board approved, \$659,000 in CDM funding.

Westario Power launched a total of twenty (20) different projects in 2007 to meet the requirements of the CDM Plan. The programs provided either technology or information to over 23,000 individuals. In addition to this, are the non-Westario Power customers who either heard the information provided in the radio advertising, or noted the conservation message in newspaper advertising related to the programs.

Over the lifetime of the technology provided through the programs it is estimated that 10,722,820 kWh will be saved.

School Programs:

Schools were targeted as a major point to focus energy conservation programs to get the message to our most valuable assets, our youth, our future.

Two programs were launched; one to grade five students and one to grade nine students, with curriculum and activities appropriate for each group.

The Dearness Environmental Society was contracted and formed a good basis for a relationship with the school throughout the year. The kids genuinely enjoyed the programs and the instructors who were trained professional educators whose passion is teaching about conservation.

The program wasn't just aimed at the students. Teachers and School Boards were delighted at the program content, and the immediate application of conservation-mindedness to every day life. School maintenance and support staff were given seminars on conservation in the schools and shown how to find energy savings.

As support to this program two environmental fund raisers were offered to schools and a lunchroom refrigerator replacement program.

These programs were well received and comments were made with respect to the quality of the Dearness staff and the excellent support from Westario Power for the schools' conservation initiatives.

Westario Power continued support to Saugeen District Secondary School's insulating paint experiment with the provision of meters on the portables to facilitate measurements of energy used.

The CDM program provided the opportunity to demonstrate energy conservation at the Wingham Public School open house.

A total of six programs involved the schools, which in general were very responsive to them. The programs started to build on themselves and encouraged continued involvement throughout the year.

As school board budgets tighten, these small savings now, and the education provided could easily translate to energy savings down the road.

Commercial and Industrial Customers:

Oddly, one of the most overlooked group of businesses are small commercial operations. These are the corner stores, and the bookkeepers, and the small restaurants that we find in any town. Westario Power, with cooperation from the local chambers of commerce and business associations, organized conservation seminars geared for the small business owner.

A luncheon atmosphere provided a relaxed and informative seminar. There was a technical aspect to the seminars, but the emphasis was on cost savings. Each of the small business owners left the seminar with tools to find energy savings.

In addition to the seminars, Small Commercial Audits were offered to interested businesses. Westario Power provided one hundred on-site energy audits to small businesses. These were well received and many business people were provided with valuable, practical advice.

Seminars were held for large customers lead by speakers from Natural Resources Canada, a federal agency. Participants included mostly large industrial customers. However, a few local health care facilities were also represented. The seminar was interactive by nature, and the participants were each provided with real and tangible suggestions for finding energy savings. Some of these customers also participated in a seminar to help the customers understand their invoice and the nature of their loads. Most customers did not know the value of understanding the data buried in their invoices, and were shown how to mine that data, how the data relates to the bill and the type of action the customer can implement to reduce their energy use and costs.

Normally this workshop is held in central locations with a registration fee of several hundred dollars. By hosting the workshop in partnership with Natural Resources Canada, the costs were lower with a registration fee of only \$50 per attendee. Each attendee also received a recording Watts-Up Meter as part of the program enhancement from Westario Power.

The large industrial and commercial customers were also offered an Utilismart Workshop to better understand the information that interval metering could provide them. And for customers using compressed air systems a “compressed air audit” was offered.

Institutions Including Municipalities:

A conversion program for replacing incandescent traffic lights with LED traffic lights was successfully delivered. Fourteen intersections were converted as a result initial installation the municipalities will benefit from lower energy costs and also reduced relamping costs.

A chance would have it, Bruce County Housing was preparing an inventory of appliances in their social housing units. Westario Power was able to offer to Bruce,

Wellington, and Huron Counties and the Town of Hanover, a refrigerator replacement program for every unit.

The housing authorities, like so many social agencies, are strapped for resources. Our programs helped replace 232 old refrigerators with new energy efficient fridges. Westario also arranged to take away the old fridges and dispose of these in an environmentally friendly way.

As part of this program the Housing Agencies were also offered the Environmental Action Kits for in-suite use. Seven hundred kits were provided. So while we were replacing the old fridges, their staff replaced old incandescent bulbs in hallways and in housing units with 2,800 compact florescent bulbs. Building superintendents were delighted with the new appliances and bulbs.

While everyone recognized that new fridges would provide energy savings, the initial capital cost was more than most could afford. The Westario Power program offered the incentive to the Housings Authorities to change the fridges for a much lower price than they could have afforded, install lower energy bulbs, and reap the benefits of the energy reduction. This program was delivered toward the end of December and was viewed as a Christmas gift by some. Enjoying the role of Santa Claus, Westario Power then also arranged to distribute about 1,000 compact florescent bulbs through local nonprofit organizations providing food hampers and baskets in Saugeen Shores, Walkerton, and Hanover.

Residential Customers:

The largest program in the residential sector was the EnergyStar Appliance Rebate which offered a 15% rebate to a maximum of \$50 for the purchase of select EnergyStar appliances. The appliances included in the program were; front and top loading washers, refrigerators, dishwashers and window air conditioners.

A total of 470 applications were received with 428 meeting the requirements. The program provided advertising in the local newspapers and also in-store support material. The message with respect to the EnergyStar rating and the benefits were reinforced by the program and the staff at the local distributors. The program did not include freezers because of very low TRC values. This did cause some problems if the list of applicable appliances had not been reviewed prior to purchase.

Project Porchlight, the delivery of a CFL to a majority of homes in the service territory, was undertaken. The project which was initiated by the Ontario Power Authority was not planned to distribute CFLs in all of the communities served by Westario Power. Through the CDM funding an additional 5,800 CFLs and their delivery was arranged resulting in coverage throughout the service territory.

Load monitors were made available through library branches and in Wellington County by the municipal office in Minto. The Kill-A-Watt meter measures the energy use of appliances and can also be used to find phantom loads (loads consuming energy while they appear to be off). Support material was provided to the distribution locations and the availability of the units was advertised in the local newspapers.

Consolidated Financial Statements of
WESTARIO POWER HOLDINGS INC.
Year ended December 31, 2007



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AUDITORS' REPORT

To the Shareholder of Westario Power Holdings Inc.

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

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

In our opinion, consolidated these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2007 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Chartered Accountants, Licensed Public Accountants

London, Canada

March 6, 2008

WESTARIO POWER HOLDINGS INC.

Consolidated Balance Sheet

December 31, 2007, with comparative figures for 2006

	2007	2006
Assets		
Currents assets:		
Cash	\$ 2,869,540	\$ 1,490,951
Accounts receivable	3,554,942	4,908,197
Accrued unbilled revenue	5,622,848	5,623,828
Inventories	717,710	785,838
Prepaid expenses	229,433	161,934
	<u>12,994,473</u>	<u>12,970,748</u>
Investment in equities	37,326	13,233
Property, plant and equipment (note 3)	24,021,458	21,036,830
Regulatory assets (note 5)	1,751,548	3,839,156
Future income tax asset (note 7)	811,365	378,600
Goodwill	2,214,322	2,214,322
	<u>\$ 41,830,492</u>	<u>\$ 40,452,889</u>

Liabilities and Shareholders' Equity

Current liabilities:		
Accounts payable and accrued liabilities	\$ 5,674,457	\$ 5,699,091
Income taxes payable (note 8)	93,695	772,243
Customer deposits and credit balances (note 4)	786,300	658,613
Current portion of long-term debt (note 7)	320,358	506,383
	<u>6,874,810</u>	<u>7,636,330</u>
Post retirement benefits (note 9)	296,913	248,346
Long-term regulatory liability (note 5)	9,749	349,673
Long-term debt (note 7)	12,948,040	11,371,834
Unrealized loss on interest rate swap (note 7)	446,464	-
Shareholders' equity:		
Share capital (note 10)	18,269,168	18,269,168
Accumulated other comprehensive income	24,092	-
Retained earnings	2,961,256	2,577,538
	<u>21,254,516</u>	<u>20,846,706</u>
Contingency (note 14)		
Subsequent event (note 15)		
	<u>\$ 41,830,492</u>	<u>\$ 40,452,889</u>

See accompanying notes to consolidated financial statements.

On behalf of the Board:

Director

Director

WESTARIO POWER HOLDINGS INC.

Consolidated Statement of Earnings and Retained Earnings

December 31, 2007, with comparative figures for 2006

	2007	2006
Revenue:		
Electricity, market related	\$ 31,693,323	\$ 31,069,657
Distribution	7,718,094	7,857,132
Retail services	67,577	68,890
Rental of electric property	130,041	130,078
Late payment charges	85,043	89,530
Other	778,439	680,671
	40,472,517	39,895,958
Expenses:		
Electricity, market related	31,693,323	31,069,657
Distribution, operation and maintenance	791,779	1,547,855
Amortization	1,650,193	1,436,328
Billing and collecting	1,224,007	1,094,744
Community relations and donations	20,392	7,270
Energy conservation	476,540	14,494
Administration	1,684,530	1,855,380
Interest on long-term debt	724,015	568,662
Unrealized loss on interest rate swap	446,464	-
Capital and municipal taxes	131,728	127,458
Other interest	57,736	86,039
Rent and maintenance of general plant	167,013	150,909
	39,067,720	37,958,796
Earnings before income taxes	1,404,797	1,937,162
Income taxes expense (note 8)		
Current	934,849	1,245,195
Future	(432,765)	(605,521)
	502,084	639,674
Net earnings	902,713	1,297,488
Retained earnings, beginning of year	2,577,538	1,646,714
Dividends	(518,995)	(366,664)
Retained earnings, end of year	\$ 2,961,256	\$ 2,577,538

See accompanying notes to consolidated financial statements.

WESTARIO POWER HOLDINGS INC.**Consolidated Statement of Comprehensive Income**

December 31, 2007, with comparative figures for 2006

		2007
Net earnings	\$	902,713
Other comprehensive income:		
Unrealized gain on available-for-sale securities		4,281
Comprehensive income	\$	906,994

See accompanying notes to consolidated financial statements.

WESTARIO POWER HOLDINGS INC.

Consolidated Statement of Accumulated Other Comprehensive Income

December 31, 2007, with comparative figures for 2006

		2007
Accumulated other comprehensive income, beginning of year	\$	-
Change in accounting policy (note 2)		19,811
Other comprehensive income		4,281
Accumulated other comprehensive income, end of year	\$	24,092

See accompanying notes to consolidated financial statements.

WESTARIO POWER HOLDINGS INC.

Consolidated Statement of Cash Flows

December 31, 2007, with comparative figures for 2006

	2007	2006
Cash provided by (used in):		
Operating activities:		
Net earnings	\$ 902,713	\$ 1,297,488
Items not involving cash:		
Amortization of organizational costs	-	42,300
Amortization of property, plant and equipment	1,650,193	1,394,028
Post-retirement benefits	48,567	37,273
Future income tax liability	(432,765)	(605,521)
Gain on disposal of capital assets	(33,323)	(31,927)
Unrealized loss on interest rate swap (note 7)	446,464	-
Changes in non-cash operating working capital (note 11)	779,368	(9,602,808)
	3,361,217	(7,469,166)
Financing activities:		
Proceeds on disposal of property, plant and equipment	78,227	39,721
Capital contributions	677,549	1,499,275
Long-term debt	1,390,181	5,024,260
Dividends paid	(518,995)	(366,664)
	1,626,962	6,196,592
Investing activities:		
Additions to property, plant and equipment	(5,357,274)	(4,311,620)
Long-term regulatory liability	(339,924)	349,673
Regulatory assets	2,087,608	1,604,244
	(3,609,590)	(2,357,703)
Increase (decrease) in cash	1,378,589	(3,630,277)
Cash, beginning of year	1,490,951	5,121,228
Cash, end of year	\$ 2,869,540	\$ 1,490,951

See accompanying notes to consolidated financial statements.

WESTARIO POWER HOLDINGS INC.

Notes to Consolidated Financial Statements
Year ended December 31, 2007

Westario Power Holdings Inc. (the "Company") was incorporated under the laws of the Province of Ontario on October 4, 2000.

The principal business of Westario Power Holdings Inc. is the distribution and sale of electricity to customers in mid-western Ontario. These businesses are regulated by the Ontario Energy Board ("OEB"). The Ontario Energy Board Act, 1998 gave the OEB increased powers and responsibilities to regulate the electricity industry. These power and responsibilities include the power to approve or fix rates for licensed distributors of electricity.

1. Significant accounting policies:

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

(a) Rate regulation:

Westario Power Inc. is regulated by the OEB under the authority of the Ontario Energy Board Act, 1998. The OEB is charged with the responsibility of approving or fixing rates for the transmission and distribution of electricity, providing continued rate protection for rural and remote electricity customers, and for ensuring distribution companies fulfill obligations to connect and service customers.

The economic impact of rate regulation is reported in these financial statements. Regulatory assets represent certain costs that may be recovered from customers in future periods through the rate-making process. In its capacity to approve or fix rates, the OEB has specified the following regulatory treatments, which have resulted in accounting treatments that differ from GAAP for enterprises operating in a non-regulatory environment.

(i) Transition costs:

Capital and operating costs incurred in respect of the transition to competitive electricity markets in Ontario (transition costs or market ready costs) have been deferred in accordance with the criteria set in the OEB's Electricity Distribution Rate Handbook and the AP Handbook. Under such regulation, certain costs are to be deferred that would be expensed when incurred under GAAP. To the extent that transition costs have been incurred which do not qualify for deferral, these costs have been expensed during the period they were incurred.

(ii) Pre-market opening energy variance:

At December 31, 2002, the Company recognized the pre-market opening energy variance (the "variance") for the period January 1, 2001 to April 30, 2002, the date of market opening, in accordance with the AP Handbook. The variance represents the difference between the utility's cost of power purchased based on time-of-use ("TOU") rate, and the amounts billed for the cost of power to non-TOU customers at an average rate for the same period.

WESTARIO POWER HOLDINGS INC.

Notes to Consolidated Financial Statements (continued)
Year ended December 31, 2007

1. Significant accounting policies:

(a) Rate regulation (continued):

(iii) Settlement variances:

The Company has deferred certain port-market opening retail settlement variances in accordance with Article 490 set out in the AP Handbook. The settlement variances relate primarily to service charges, non-competitive electricity charges, and power charges. Other than the variances for cost of imported power, the nature of the settlement variances is such that their balances shall change each reporting period-end date.

(iv) Conservation and demand management costs:

Conservation and demand management ("CDM") program costs in 2007 were \$476,540 (2006 - \$14,494) of which \$nil (2006 - \$nil) was capitalized. Provincial regulations allowed electricity distribution companies to apply to the OEB to adjust its distribution rates in 2005 for its approved third instalment of its market adjusted requirement ("MARR"). OEB approval in regard to this final MARR instalment is conditional on investing an amount equal to one year's incremental returns in conservation and demand management initiatives, by no later than April 30, 2008. The Company's final incremental MARR was \$659,218.

(v) OEB incremental cost assessments:

OEB costs which had been assessed to the Company in 2005, and which are incremental to amounts already included in the Company's rates, were deferred in accordance with the AP Handbook. These costs are being recovered in rates beginning in 2006. To the extent that OEB cost assessments have been incurred which do not qualify for deferral, these costs have been expensed during the period they were incurred.

(b) Revenue recognition:

In accordance with OEB regulation, the Company recognizes as revenue the regulated distribution tariffs associated with energy distributed and variances between energy purchase costs and energy billed are recorded as regulatory assets or liabilities for future rate application consideration.

The Company follows the practice of cycle billing customers' accounts and revenue is recognized in the period billed. An accrual is made in the accounts at December 31, for power supplied but not billed to customers between the date the meters were last read and the end of the year.

Interest revenue is recognized when the interest is earned.

WESTARIO POWER HOLDINGS INC.

Notes to Consolidated Financial Statements (continued)
Year ended December 31, 2007

1. Significant accounting policies:

(c) Cash

Cash consists of cash on hand and bank balances.

(d) Spare transformers and meters:

Spare transformers and meters are classified as capital assets in accordance with guidance in the AP Handbook.

(e) Inventories:

Inventories are stated at the lower of laid down cost basis and net realizable value

(f) Property, plant and equipment:

Property, plant and equipment are recorded at cost. Amortization is provided on a straight-line basis using the following annual rates:

Asset	Rate
Buildings	4%
Distribution stations	3%
Distribution lines, overhead	4%
Distribution lines, underground	4%
Distribution equipment and transformers	4%
Meters	4%
Computer software	20%
Communications equipment	20%
Computer equipment	20%
Office furniture	10%
Tools and garage equipment	10%
Trucks	12.5% - 25%

(g) Contributed capital:

Contributions are received from developers and contractors for capital costs incurred by the Company. These contributions are included as a reduction to the cost of the related capital assets when those assets are placed in service.

WESTARIO POWER HOLDINGS INC.

Notes to Consolidated Financial Statements (continued)
Year ended December 31, 2007

1. Significant accounting policies:

(h) Impairment of long-lived assets:

Long-lived assets, including property, plant and equipment and purchased intangibles subject to amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset. Assets to be disposed of would be separately presented in the balance sheet and reported at the lower of the carrying or fair value less costs to sell, and are no longer depreciated. The assets and liabilities of a disposed group classified as held for sale would be presented separately in the appropriate assets and liability section of the balance sheet.

(i) Goodwill:

Goodwill reflects the excess of the purchase price over the fair value of net tangible assets acquired. Goodwill is not amortized, but tested for impairment on an annual basis. No goodwill was impaired during the year.

(j) Income taxes:

The Company uses the asset and liability method of accounting for income taxes. Under the asset and liability method, future income tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying values of existing assets and liabilities and their respective tax bases. Future income tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future income tax assets and liabilities of a change in tax rates is recognized in income in the year that includes the date of enactment or substantive enactment.

In assessing the realizability of future income tax assets, management considers whether it is more likely than not that some portion or all of the future income tax assets will be realized. The ultimate realization of future income tax assets is dependent upon the generation of future taxable income during the period in which the temporary differences are deductible. Management considers the scheduled reversals of future income tax liabilities, the character of the future income tax asset, and tax planning strategies in making this assessment. To the extent that management believes that the realization of future income tax assets does not meet the more likely than not realization criteria, a valuation allowance is recorded against the future income tax assets.

(k) Post-retirement benefits:

The Company provides post-retirement life insurance benefits to eligible retired employees. The benefits earned by employees are actuarially determined using management's best estimate of salary escalation, retirement ages of employees and expected benefit costs.

Actuarial gains and losses in a year are combined with the unamortized balance of gains and losses from prior years. The portion of the total that exceeds ten percent of the accrued benefit obligation is amortized over the average remaining service period of the active employees. Past service costs arising from plan amendments are amortized over the future years of service of active employees.

WESTARIO POWER HOLDINGS INC.

Notes to Consolidated Financial Statements (continued)
Year ended December 31, 2007

1. Significant accounting policies:

(l) Derivative instruments:

Derivative financial instruments are contracts that require or provide the opportunity to exchange cash flows or payments determined by applying certain rates, indices or changes therein to notional contract amounts. The Company uses derivative financial instruments, primarily interest rate swaps, in order to manage interest rate exposure. The Company's policy is not to utilize financial instruments for trading or speculative purposes. From January 1, 2007, derivatives are carried at fair value and are reported on the Balance Sheet as other assets, where they have a positive fair value and as derivative financial liabilities where they have a negative fair value.

(m) Use of estimates:

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

2. Change in accounting policies:

On January 1, 2007, the Company adopted the following new accounting standards issued by the Canadian Institute of Chartered Accountants:

- (i) Section 1530, "Comprehensive Income", establishes standards for reporting and displaying comprehensive income. Comprehensive income is defined as the change in equity from transactions and other events from non-owner sources. Other comprehensive income refers to items recognized in comprehensive income but that are excluded from net income calculated in accordance with Canadian generally accepted accounting policies.
- (ii) Section 3251, "Equity", establishes standards for the presentation of equity in the reporting period.
- (iii) Section 3855, "Financial Instruments - Recognition and Measurement", establishes standards for recognizing and measuring financial instruments, namely financial assets, financial liabilities and derivatives.
- (iv) Section 3861, "Financial Instruments - Disclosure and Presentation", establishes standards for presentation and disclosure of financial instruments, namely financial assets, financial liabilities and derivatives.
- (v) Section 3865, "Hedges", establishes standards for which hedge accounting is permissible and how it may be applied. There were no transitional adjustments on adoption of these standards.

Under these new standards, all financial instruments are required to be initially measured at fair value and classified into one of the following five categories: held for trading, held-to-maturity investments, loans and receivables, available-for-sale financial assets or other financial liabilities. Subsequent measurement and recognition of changes in fair value of financial instruments depend on their initial classification.

The Company has implemented the following classifications:

Held-for-trading

Cash is designated as "Financial Assets Held for Trading". These financial assets are marked-to-market through net earnings at each period end.

WESTARIO POWER HOLDINGS INC.

Notes to Consolidated Financial Statements (continued)
Year ended December 31, 2007

2. Change in accounting policies (continued):

Loans and receivables

Accounts receivable are designated as "Loans and Receivables". After their initial fair value measurement, they are measured at amortized cost using the effective interest rate method.

Available for sale investments

Investments in equities are designated as "Available-for-sale Financial Assets". When they have a quoted market price in an active market, they are carried at fair value with changes in fair value recognized as a separate component of other comprehensive income. Where a decline in fair value is determined to be other than temporary, the amount of the loss is removed from other comprehensive income and recognized in the income statement.

Other financial liabilities

Accounts payable and accrued liabilities, amounts due to related parties, and long-term debt are designated as "Other Financial Liabilities". After their initial fair value measurement, they are measured at amortized cost using the effective interest rate method.

These accounting policy changes were adopted on a prospective basis with no restatement of prior period financial statements.

In accordance with the provisions of these new standards, the Company reflected an increase of \$19,811 to "Investment in equities" and an increase of \$19,811 to "Accumulated other comprehensive income" to reflect the market value of the equities at January 1, 2007.

3. Property, plant and equipment:

		2007		2006	
	Cost	Accumulated amortization	Net book value	Net book value	
Land	\$ 227,769	\$ -	\$ 227,769	\$ 242,769	
Buildings	2,450,304	100,107	2,350,197	4,494	
Distribution stations	3,157,391	1,006,924	2,150,467	2,214,408	
Distribution lines, overhead	10,693,412	3,009,337	7,684,075	7,551,555	
Distribution lines, underground	6,573,050	1,810,733	4,762,317	4,186,871	
Distribution equipment and transformers	258,631	258,631	-	-	
Distribution transformers	5,291,320	1,315,315	3,976,005	3,645,593	
Meters	2,333,505	586,795	1,746,710	1,662,848	
Computer software	267,519	262,601	4,918	58,421	
Communications equipment	99,188	73,733	25,455	31,629	
Computer equipment	767,047	686,692	80,355	52,358	
Office furniture	227,058	115,089	111,969	79,437	
Tools and garage equipment	315,152	182,622	132,530	106,922	
Trucks	1,563,355	855,843	707,512	540,927	
Assets under construction	61,179	-	61,179	658,598	
	\$ 34,285,880	\$ 10,264,422	\$ 24,021,458	\$ 21,036,830	

WESTARIO POWER HOLDINGS INC.

Notes to Consolidated Financial Statements (continued)
Year ended December 31, 2007

4. Customer deposits and credit balances:

Customer deposits include security deposits for energy consumption bearing interest at a rate of prime less 2% per annum and developer deposits held in accordance with regulation.

5. Regulatory assets:

	2007	2006
2006 OEB approved recoverable regulatory assets	\$ 7,005,341	\$ 6,828,639
Post market energy variances	590,929	782,511
Deferred payment in lieu of taxes	55,811	55,811
Other	94,118	162,890
	7,746,199	7,829,851
Less recovery of regulatory assets	(5,994,651)	(3,990,695)
	\$ 1,751,548	\$ 3,839,156

Recovery of regulatory amounts:

In December, 2003, the OEB permitted the Company to commence recovery of regulatory assets through distribution rates over a four-year period commencing March 1, 2005. During fiscal 2006, the OEB undertook a detailed review to validate the amounts for final recovery. The OEB has approved Phase II recovery of regulatory assets commencing May 1, 2006, which will amount to an approximate recovery of \$1,010,690 (2007-\$1,784,753) during the Company's fiscal 2008 year.

Included in regulatory assets is \$689,597 related to low voltage system charges from Hydro One Networks Inc. ("Hydro One"). A corresponding amount is being repaid to Hydro One over several years and an accrual has been recognized. The amount due in 2008 is \$339,224 and is included under "Accounts payable and accrued liabilities" and the balance of \$9,749 has been recorded as a long-term liability.

6. Bank indebtedness :

The Company has a bank operating line of credit of \$1,897,399, available by way of letters of credit. At December 31, 2007, the line was fully drawn by way of a letter of credit, issued in favour of the Independent Electricity System Operator ("IESO"), to satisfy the Company's prudential support obligation for participation in and withdrawing electricity from the IESO controlled electricity grid.

The Company has a bank operating line of credit of \$100,000, available by way of letters of credit. At December 31, 2007, the line was fully drawn by way of a letter of credit, issued in favour of The Ministry of Environment with regards to compliance under the terms of the Provisional Certificate of Approval for Waste Management System no. 8799-6DDKU5.

The Company has a bank operating line of credit of \$3,500,000. At December 31, 2007, the amount drawn by the Company under the line was \$nil (2006 - \$nil). The line of credit bears interest at bank prime rate less 0.50%. At December 31, 2007, the rate was 5.50% (2006 - 5.50%).

The line of credits and operating line of credit are secured by a security agreement conveying a security interest in the personal property of the Company and unlimited guarantees.

WESTARIO POWER HOLDINGS INC.

Notes to Consolidated Financial Statements (continued)
Year ended December 31, 2007

7. Long-term debt:

	2007	2006
Notes payable to shareholders of parent company, 5.47% payable quarterly interest only, due on demand	\$ 5,260,460	\$ 5,583,888
Non-revolving term instalment loan bearing interest at the Banker's Acceptance rate of 5.33% plus a stamping fee of 0.80%, payable in blended monthly instalments of \$48,700, due December 2010	5,534,694	-
Non-revolving term instalment loan bearing interest at the Banker's Acceptance rate of 5.38% plus a stamping fee of 0.80%, payable in blended monthly instalments of \$18,150, due December 2010	2,473,244	-
Term instalment loans bearing interest at prime less 0.50%, payable in blended monthly instalments over 15 to 20 years, due December 2009	-	6,294,329
	13,268,398	11,878,217
Current portion of shareholders' loans	-	(123,428)
Current portion of term loans	(320,358)	(382,955)
	\$ 12,948,040	\$ 11,371,834

The shareholder notes are only due on demand to the extent the shareholder requests payment ninety days prior to year end. In the event a request is made, the Company is obligated to repay the shareholder during the following fiscal year. No repayments are required without a written request. No amounts were requested by shareholders of the parent company on or before September 30, 2007.

The term instalment loans are secured by a security agreement conveying a security interest in the personal property of the Company, acknowledgement of fire insurance and an unlimited guarantee from Westario Power Holdings Inc., the Company's sole shareholder, and an unlimited guarantee from Westario Power Services Inc., an affiliated company wholly-owned by Westario Power Holdings Inc.

Westario Power Inc. has entered into an interest rate swap agreement on a notional principal of \$5,655,638 as at June 28, 2007 maturing on June 28, 2022. The swap is a receive variable, pay fixed swap with the CIBC World Markets. This agreement has effectively converted variable interest rates on the unsecured Banker's Acceptances to an effective fixed interest rate of 5.33% plus stamping fee.

Westario Power Inc. has entered into an interest rate swap agreement on a notional principal of \$2,500,000 as at July 3, 2007 maturing on July 3, 2027. The swap is a receive variable, pay fixed swap with the CIBC World Markets. This agreement has effectively converted variable interest rates on the unsecured Banker's Acceptances to an effective fixed interest rate of 5.38% plus stamping fee.

The two swaps entered into by Westario Power Inc. do not meet the standard to apply hedge accounting. Accordingly, the interest rate swap contracts are marked to market at each year end with the gain or loss recorded in the income statement. The loss recorded in 2007 was \$446,464.

WESTARIO POWER HOLDINGS INC.

Notes to Consolidated Financial Statements (continued)

Year ended December 31, 2007

8. Income taxes:

(a) Income tax status:

The Company is exempt from income taxes under the Income Tax Act (Canada). Effective October 1, 2001 and pursuant to the EA (1998) (Ontario) the Company is required to make payments in lieu of tax to the Ontario Electricity Financial Corporation. The amount of payments in lieu of tax will be approximately equivalent to the income and capital taxes that would have to be paid if the Company was a taxable corporation under the Income Tax Act (Canada).

(b) Income tax rate:

The Company's effective income tax rates differed from the statutory combined federal and provincial rates primarily due to the following:

	2007		2006	
Earnings before income taxes	\$	1,404,797	\$	1,937,162
Income tax expense based on combined federal and provincial statutory income tax rate of 36.12% (2006 - 36.12%)	\$	507,413	\$	699,703
Tax effect of undeductible amounts		6,991		7,195
Impact on future income taxes resulting from statutory rate decreases		57,393		(4,213)
Other items		(69,713)		(63,011)
Income tax expense recognized	\$	502,084	\$	639,674

WESTARIO POWER HOLDINGS INC.

Notes to Consolidated Financial Statements (continued)

Year ended December 31, 2007

8. Income taxes (continued):

(c) Future income taxes:

The tax effects of temporary differences that give rise to significant portions of the future tax assets and future tax liabilities at December 31 are presented below:

	2007	2006
Future income tax assets:		
Property, plant and equipment, difference between net book value and tax cost	\$ 1,285,735	\$ 1,402,403
Non-deducted post retirement benefits	86,105	89,703
Unrealized interest for tax purposes	129,475	-
	1,501,315	1,492,106
Future income tax liabilities:		
Intangible assets, difference between net book value and tax cost	(125,274)	(124,056)
Regulatory assets	(570,618)	(993,540)
Other	5,942	4,090
	(689,950)	(1,113,506)
Net future income tax asset	\$ 811,365	\$ 378,600

The determination of whether recovery or settlement of an asset or liability will result in future income tax outflows or benefits is determined by reference to the difference between carrying values and tax basis of assets and liabilities. Management compares the carrying value and tax basis of assets and liabilities at December 31 of each year, to determine the temporary differences and the timing of the expected reversal. Taxable temporary differences give rise to future income tax liabilities while deductible temporary differences give rise to future income tax assets.

WESTARIO POWER HOLDINGS INC.

Notes to Consolidated Financial Statements (continued)

Year ended December 31, 2007

9. Post-retirement benefits:

(a) Pension plan:

The Company participates in the Ontario Municipal Employees Retirement Fund ("OMERS"), a multi-employer plan, on behalf of its employees. The plan is a contributory defined benefit pension plan. Contributions to the plan for 2007 were \$128,726 (2006 - \$137,226).

(b) Other benefits:

The Company provides post-retirement life insurance benefits to eligible retired employees. In measuring the Company's accrued benefit obligation, a discount rate of 5.00% (2006 - 5.75%) was assumed by management. A 3% (2006 - 3%) salary increase for life insurance coverage was assumed. The Company's liability at December 31 for this plan is as follows:

	2007	2006
Accrued benefit obligation	\$ 404,581	\$ 343,573

The transition obligation has been amortized over the average remaining service life of current employees, which is six years. The resulting liability on the balance sheet at year end is as follows:

	2007	2006
Post-retirement benefit liability	\$ 296,913	\$ 248,346

Other information about the Company's plan for the year ended December 31, is as follows:

	2007	2006
Service cost	\$ 2,195	\$ 1,706
Interest cost	19,897	19,639
Benefit paid	12,303	11,275
Contributions paid	25,568	24,606

WESTARIO POWER HOLDINGS INC.

Notes to Consolidated Financial Statements (continued)
Year ended December 31, 2007

10. Share capital:

	2007	2006
Authorized:		
Unlimited common shares, voting		
Issued:		
10,000 common shares	\$ 18,269,168	\$ 18,269,168

11. Change in non-cash operating working capital:

	2007	2006
Accounts receivable, net of allowance	\$ 1,353,255	\$ (3,498,787)
Unbilled revenue	980	(266,138)
Inventories	68,128	(53,325)
Prepaid expenses	(67,499)	49,417
Accounts payable and accrued liabilities	(24,635)	112,353
Customers deposits and credit balances	127,687	(1,248,276)
Income taxes payable	(678,548)	230,143
Demand instalment loans	-	(4,928,195)
	\$ 779,368	\$ (9,602,808)

12. Public liability insurance:

The Company joined the Municipal Electrical Association Reciprocal Insurance Exchange ("MEARIE") in 2000. MEARIE is a pooling of public liability insurance risks of many of the municipal utilities in Ontario. All members of the pool are subject to assessment for losses experienced by the pool for the years in which they were members on a pro-rata basis based on the total of their respective service revenues. It is anticipated that should such an assessment occur it would be funded over a period of up to five years. At December 31, 2007, no assessments have been made.

13. Credit risks:

Credit risk is the risk that a counterparty will fail to discharge its obligation to the Company reducing the expected cash inflow from Company assets recorded at the balance sheet date. Credit risk can be concentrated in debtors that are similarly affected by economic or other conditions.

The Company has assessed that there are no significant concentrations of credit risk other than the present uncertainty relating to the recovery of regulatory assets. The final regulatory amount recoverable will be assessed in future years by the regulator after the audit of those costs.

WESTARIO POWER HOLDINGS INC.

Notes to Consolidated Financial Statements (continued)
Year ended December 31, 2007

14. Contingency:

The Company has a future asset retirement obligation related to an environmental liability to dispose of wooden creosote-treated hydro poles. Management is currently unable to estimate the future costs for disposal at this time as a detailed inventory of creosote-treated poles is use and their remaining useful lives are not available.

15. Subsequent event:

On January 1, 2008 Westario Power Services Inc., Westario Power Inc. and Westario Power Holdings Inc. amalgamated to form a new company called Westario Power Inc.

16. Comparative amounts:

Comparative amounts for the prior year have been restated to conform to the current year presentation.

Rate Base Overview

Introduction

A projection of WPI'S rate base is provided for both the Bridge Year (2008) and the Test Year (2009). Historical data pertaining to rate base is also presented for 2006 Board approved, 2006 Actual and 2007 Actual. WPI'S forecast rate base for the test year is \$33,630,199. The rate base underlying the test year revenue requirement includes a forecast of net fixed assets, plus a working capital allowance. Net fixed assets are based on an average of the opening and closing balance of gross assets in service minus accumulated depreciation and contributed capital. Details for WPI's working capital allowance are provided In Exhibit 2, Tab 4, Schedule 2.

1 **Rate Base Summary Table**

2

3 The following is the Rate Base Summary Table

4

5

RateMaker 2009 release 1.1 © Elenchus Research Associates

D1 Rate Base Summary

Working Capital Allowance

<u>2009</u>		
<u>Eligible Distribution Expenses:</u> (1)		
3500-Distribution Expenses - Operation		480,400
3550-Distribution Expenses - Maintenance		1,164,675
3650-Billing and Collecting		1,242,900
3700-Community Relations		35,500
3800-Administrative and General Expenses		1,888,350
3950-Taxes Other Than Income Taxes		56,600
Total Eligible Distribution Expenses		4,868,425
3350-Power Supply Expenses (2)		33,551,217
Total Expenses for Working Capital		38,419,642
Working Capital Allowance	15.0%	5,762,946
(1) From sheet B4		
(2) From sheet C2		

<u>TOTAL RATE BASE</u>	
<u>2009</u>	
<u>Net Fixed Assets in Service:</u> (3)	
Opening Balance	27,491,909
Closing Balance	<u>28,242,596</u>
Average Balance	27,867,253
Working Capital Allowance	5,762,946
TOTAL RATE BASE	33,630,199
(3) From Sheet B3	

Variance Analysis on Rate Base Table

This section includes a Variance Analysis on Rate Base Table which provides a listing of the Net Capital Assets in Service and Working Capital for the 2006 EDR Approved, 2006 Actual, 2007 Actual, 2008 Bridge Year and Test Year with the year over year variances. Rate Base Table is provided at the end of this section.

2006 Actual vs. 2006 EDR

The total rate base for 2006 was \$27,061,081 vs. the 2006 EDR approved amount of \$25,097,598. This represents an increase in the total rate base of \$1,963,483 or 7.8%. The aforementioned increase is attributable to an increase in the average balance of capital assets in the amount of \$1,938,981 (9.8%) and an increase in the working capital allowance of \$24,502 (0.5%).

Because the 2006 EDR approved rate was based on 2004 data, the increase in the average capital asset balance is due to the net increase in capital assets in 2005 and 2006 as evidenced in Exhibit 2, Tab 2, Schedule 3. WPI remains committed to providing a safe and reliable distribution system for its customers, the public and its employees and in doing so has spent considerable funds on its distribution plant.

The increase in working capital is the net impact of a decrease in total eligible distribution expenses of approximately \$542,000, most notably in administrative and general expenses, and an increase in operation and maintenance distribution expenses due to unplanned outages. The decrease in total distribution expenses is offset by an increase in power supply expenses of approximately \$706,000. The increase in the power supply expenses was as a result of an increase in Power Purchased due to an increase in the price of the commodity, the implementation of a new total loss factor, new Hydro One Low Voltage charges and decreases in Transmission, Connection and Network charges.

2007 Actual vs. 2006 Actual

The total rate base for 2007 was \$29,506,403 vs. the 2006 actual of \$27,061,081. This represents an increase in the total rate base of \$2,445,322 or 9.0%. The increase is attributable to the increase in the average net capital assets of \$2,302,075 (10.5%) and an increase in the working capital allowance of \$143,247 (2.7%).

The increase in the average capital asset balance is due to the net increase in capital assets in 2007 as evidenced in Exhibit 2, Tab 2, Schedule 3. In addition to capital assets added to the distribution plant included in 2007 assets, is the completion of WPI's new operational facility as evidenced in Exhibit 2, Tab 3, Schedule 5.

The increase in the working capital allowance is attributable to an overall increase in eligible distribution expenses of approximately \$331,000 as found in Exhibit 4, Tab 1, Schedule 2. This increase is largely due to increased spending in Conservation and Demand Management programs under Third Tranche funding, and increases in outside services for pay equity, Collective Agreement contract negotiations and the amalgamation of the Westario Power Group of companies. Increases in administrative and general expenses were offset by decreases in operation and maintenance distribution expenses. In 2007, WPI received finalization of meter exit fees from Hydro One Networks Inc. that further reduced distribution expenses. Power supply expenses increased by approximately \$623,000 due to increased consumption year over year; thereby affecting power, network, transmission and connection.

2008 Bridge vs. 2007 Actual

The total rate base for 2008 bridge is projected at \$32,298,421 vs. the 2007 actual of \$29,506,403. This represents an increase in the total rate base of \$2,792,018 (9.5%). The increase is attributable to the increase in the average net capital assets of \$2,554,171 (10.6%) and an increase in the working capital allowance of \$237,847 (4.4%) as shown in Exhibit 2, Tab 1, Schedule 3.

The increase in the average capital asset balance is due to the net increase in capital assets in 2007 and 2008 as evidenced in the Fixed Asset Continuity Statements reported in Exhibit 2,

1 Tab 2, Schedule 1. In addition to capital assets added to the distribution plant, included in 2007
2 assets is the completion of WPI's operational facility.

3
4 As evidenced in Exhibit 4, Tab 1, Schedule 2, there is an overall increase in operation and
5 maintenance distribution expenses of approximately \$980,000. This increase is attributed to
6 ongoing field data collection and meeting compliance with Measurement Canada on a large
7 number of poly-phase demand meters. The large drop in community relations reflects the
8 termination of Conservation and Demand Management programs in 2008. Decreases in Billing
9 and Collecting of approximately \$140,000 are due to projected decreases in bad debt expense
10 and the elimination of a full time employee which occurred mid-2007. Projected power supply
11 expenses are estimated at approximately \$1,330,000 more in 2008 due to an increase in
12 projected consumption, therefore affecting power, transmission and connection charges.

13
14 **2009 Test vs. 2008 Bridge**

15 The total rate base for 2009 test is projected at \$33,630,199 vs. the 2008 bridge of \$32,298,421.
16 This represents an increase in the total rate base of \$1,331,779 or 4.1%. The increase is
17 attributable to the increase in the average net capital assets of \$1,258,656 (4.7%) and an
18 increase in the working capital allowance of \$73,123 (1.3%) as shown in Exhibit 2, Tab 1,
19 Schedule 3.

20
21 The increase in the average capital asset balance is due to the net increase in capital assets in
22 2008 and 2009 as evidenced in in the Fixed Asset Continuity Statements reported in Exhibit 2,
23 Tab 2, Schedule 1. WPI remains committed to providing a safe and reliable distribution system
24 for its customers, the public and its employees and in doing so projects spending considerable
25 funds on its distribution plant.

26
27 As evidenced in Exhibit 4, Tab 1, Schedule 2, there was an overall decrease in operation and
28 maintenance distribution expenses of approximately \$194,000. This decrease is mostly
29 attributed to the decrease in meter maintenance costs due to fewer poly phase meter
30 replacements in the 2009 Test year than in 2008 Bridge Year. There is an increase in billing
31 and collecting in the amount of approximately \$97,000 due to anticipated increases in bad debt

1 and collection expenses. WPI projects minimal change in 2008 bridge and 2009 test for
2 community relations, administrative and general expenses and taxes other than income taxes.
3 Projected power supply expenses are estimated at approximately \$528,000 more in 2009 test
4 vs. 2008 bridge due to an increase in projected consumption, therefore affecting power,
5 transmission and connection charges, and an increase in proposed Hydro One Networks Inc.
6 Low Voltage charges.

7

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G6 Variance Analysis: Rate Base

Variances in excess of \$274,919 are shown in bold					
	2009 Projection	2008 Projection		Var \$	Var %
<i>Net Capital Assets in Service:</i>					
Opening Balance	27,491,909	25,725,285		1,766,624	6.9%
Ending Balance	28,242,596	27,491,909		750,687	2.7%
Average Balance	27,867,253	26,608,597		1,258,656	4.7%
Working Capital Allowance (see below)	5,762,946	5,689,824		73,123	1.3%
Total Rate Base	33,630,199	32,298,421		1,331,779	4.1%

Expenses for Working Capital

Variances in excess of \$66,296 are shown in bold					
<i>Eligible Distribution Expenses:</i>					
3500-Distribution Expenses - Operation	480,400	332,475		147,925	44.5%
3550-Distribution Expenses - Maintenance	1,164,675	1,505,770		(341,095)	(22.7%)
3650-Billing and Collecting	1,242,900	1,146,035		96,865	8.5%
3700-Community Relations	35,500	23,470		12,030	51.3%
3800-Administrative and General Expenses	1,888,350	1,850,765		37,585	2.0%
3950-Taxes Other Than Income Taxes	56,600	50,600		6,000	11.9%
Total Eligible Distribution Expenses	4,868,425	4,909,115		(40,690)	(0.8%)
3350-Power Supply Expenses	33,551,217	33,023,042		528,175	1.6%
Total Expenses for Working Capital	38,419,642	37,932,157		487,485	1.3%
Working Capital factor	15.0%	15.0%			
Working Capital Allowance	5,762,946	5,689,824		73,123	1.3%

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G6 Variance Analysis: Rate Base

Variances in excess of \$257,253 are shown in bold					
	2008 Projection	2007 Actual		Var \$	Var %
<i>Net Capital Assets in Service:</i>					
Opening Balance	25,725,285	22,383,568		3,341,717	14.9%
Ending Balance	27,491,909	25,725,285		1,766,624	6.9%
Average Balance	26,608,597	24,054,427		2,554,171	10.6%
Working Capital Allowance (see below)	5,689,824	5,451,977		237,847	4.4%
Total Rate Base	32,298,421	29,506,403		2,792,018	9.5%

Expenses for Working Capital

Variances in excess of \$60,868 are shown in bold					
<i>Eligible Distribution Expenses:</i>					
3500-Distribution Expenses - Operation	332,475	319,525		12,950	4.1%
3550-Distribution Expenses - Maintenance	1,505,770	535,748		970,022	181.1%
3650-Billing and Collecting	1,146,035	1,286,330		(140,295)	(10.9%)
3700-Community Relations	23,470	485,353		(461,883)	(95.2%)
3800-Administrative and General Expenses	1,850,765	1,907,783		(57,018)	(3.0%)
3950-Taxes Other Than Income Taxes	50,600	118,449		(67,849)	(57.3%)
Total Eligible Distribution Expenses	4,909,115	4,653,188		255,927	5.5%
3350-Power Supply Expenses	33,023,042	31,693,322		1,329,720	4.2%
Total Expenses for Working Capital	37,932,157	36,346,510		1,585,647	4.4%
Working Capital factor	15.0%	15.0%			
Working Capital Allowance	5,689,824	5,451,977		237,847	4.4%

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G6 Variance Analysis: Rate Base

Variances in excess of \$223,836 are shown in bold					
	2007 Actual	2006 Actual		Var \$	Var %
<i>Net Capital Assets in Service:</i>					
Opening Balance	22,383,568	21,121,135		1,262,433	6.0%
Ending Balance	25,725,285	22,383,568		3,341,717	14.9%
Average Balance	24,054,427	21,752,352		2,302,075	10.6%
Working Capital Allowance (see below)	5,451,977	5,308,729		143,247	2.7%
Total Rate Base	29,506,403	27,061,081		2,445,322	9.0%

Expenses for Working Capital

Variances in excess of \$56,390 are shown in bold					
<i>Eligible Distribution Expenses:</i>					
3500-Distribution Expenses - Operation	319,525	406,210		(86,685)	(21.3%)
3550-Distribution Expenses - Maintenance	535,748	1,184,709		(648,961)	(54.8%)
3650-Billing and Collecting	1,286,330	1,139,082		147,248	12.9%
3700-Community Relations	485,353	18,791		466,562	2482.9%
3800-Administrative and General Expenses	1,907,783	1,478,869		428,914	29.0%
3950-Taxes Other Than Income Taxes	118,449	94,211		24,238	25.7%
Total Eligible Distribution Expenses	4,653,188	4,321,872		331,316	7.7%
3350-Power Supply Expenses	31,693,322	31,069,657		623,665	2.0%
Total Expenses for Working Capital	36,346,510	35,391,529		954,981	2.7%
Working Capital factor	15.0%	15.0%			
Working Capital Allowance	5,451,977	5,308,729		143,247	2.7%

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G6 Variance Analysis: Rate Base

Variances in excess of \$198,134 are shown in bold					
	2006 Actual	2006 EDR Approved		Var \$	Var %
<i>Net Capital Assets in Service:</i>					
Opening Balance	21,121,135	20,118,370		1,002,765	5.0%
Ending Balance	22,383,568	19,508,372		2,875,196	14.7%
Average Balance	21,752,352	19,813,371		1,938,981	9.8%
Working Capital Allowance (see below)	5,308,729	5,284,227		24,502	0.5%
Total Rate Base	27,061,081	25,097,598		1,963,483	7.8%

Expenses for Working Capital

Variances in excess of \$61,362 are shown in bold					
<i>Eligible Distribution Expenses:</i>					
3500-Distribution Expenses - Operation	406,210	97,077		309,133	318.4%
3550-Distribution Expenses - Maintenance	1,184,709	945,725		238,984	25.3%
3650-Billing and Collecting	1,139,082	1,207,662		(68,580)	(5.7%)
3700-Community Relations	18,791	6,300		12,491	198.3%
3800-Administrative and General Expenses	1,478,869	2,549,321		(1,070,452)	(42.0%)
3950-Taxes Other Than Income Taxes	94,211	58,549		35,662	60.9%
Total Eligible Distribution Expenses	4,321,872	4,864,634		(542,762)	(11.2%)
3350-Power Supply Expenses	31,069,657	30,363,546		706,111	2.3%
Total Expenses for Working Capital	35,391,529	35,228,180		163,349	0.5%
Working Capital factor	15.0%	15.0%			
Working Capital Allowance	5,308,729	5,284,227		24,502	0.5%

1 **Fixed Asset Continuity Statements**

2

3 The following attachment is the Fixed Asset Continuity Statements.

4

Capital Asset Continuity Statements

* Asset retirements and other changes

	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other *	Amortization	
1805-Land					
Gross Assets	107,769	135,000			242,769
Accumulated Amortization					
Net Book Value	107,769	135,000			242,769
1808-Buildings and Fixtures					
Gross Assets	6,517				6,517
Accumulated Amortization	(1,210)		(160)	(653)	(2,023)
Net Book Value	5,307		(160)	(653)	4,494
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	3,073,798				3,073,798
Accumulated Amortization	(507,072)		(70,464)	(284,630)	(862,166)
Net Book Value	2,566,726		(70,464)	(284,630)	2,211,632
1830-Poles, Towers and Fixtures					
Gross Assets	3,892,678	769,162	149,218		4,811,058
Accumulated Amortization	(601,476)		(91,247)	(402,126)	(1,094,849)
Net Book Value	3,291,202	769,162	57,971	(402,126)	3,716,209
1835-Overhead Conductors and Devices					
Gross Assets	5,137,278	1,558,013	39,646		6,734,937
Accumulated Amortization	(786,408)		(104,824)	(551,196)	(1,442,428)
Net Book Value	4,350,870	1,558,013	(65,178)	(551,196)	5,292,509
1840-Underground Conduit					
Gross Assets	1,315,937	595,180	183,429		2,094,546
Accumulated Amortization	(199,475)		(34,477)	(159,181)	(393,133)
Net Book Value	1,116,462	595,180	148,952	(159,181)	1,701,413
1845-Underground Conductors and Devices					
Gross Assets	3,444,539	1,261,952	856,664		5,563,155
Accumulated Amortization	(608,691)		(94,648)	(426,972)	(1,130,311)
Net Book Value	2,835,848	1,261,952	762,016	(426,972)	4,432,844

Capital Asset Continuity Statements

* Asset retirements and other changes

	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other *	Amortization	
1850-Line Transformers					
Gross Assets	3,824,513	2,211,021	(138,546)		5,896,988
Accumulated Amortization	(598,029)		(109,259)	(435,961)	(1,143,249)
Net Book Value	3,226,484	2,211,021	(247,805)	(435,961)	4,753,739
1855-Services					
Gross Assets	2,069,198	517,571	140,283		2,727,052
Accumulated Amortization	(286,022)		(49,602)	(220,310)	(555,934)
Net Book Value	1,783,176	517,571	90,681	(220,310)	2,171,118
1860-Meters					
Gross Assets	1,866,214	363,794	72,019		2,302,027
Accumulated Amortization	(255,575)		(41,497)	(193,515)	(490,587)
Net Book Value	1,610,639	363,794	30,522	(193,515)	1,811,440
1915-Office Furniture and Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1920-Computer Equipment - Hardware					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1925-Computer Software					
Gross Assets	255,224		12,295		267,519
Accumulated Amortization	(75,340)		(26,752)	(107,006)	(209,098)
Net Book Value	179,884		(14,457)	(107,006)	58,421
1930-Transportation Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					

Capital Asset Continuity Statements

* Asset retirements and other changes

	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other *	Amortization	
1935-Stores Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1940-Tools, Shop and Garage Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1945-Measurement and Testing Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1950-Power Operated Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1955-Communication Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1960-Miscellaneous Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1975-Load Management Controls - Utility Premises					
Gross Assets	258,630		1		258,631
Accumulated Amortization	(189,662)		(25,864)	(43,105)	(258,631)
Net Book Value	68,968		(25,863)	(43,105)	

Capital Asset Continuity Statements

* Asset retirements and other changes	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other *	Amortization	
1995-Contributions and Grants - Credit					
Gross Assets	(1,774,197)	(2,442,627)	(220,355)		(4,437,179)
Accumulated Amortization	139,234		39,913	245,012	424,159
Net Book Value	(1,634,963)	(2,442,627)	(180,442)	245,012	(4,013,020)
TOTAL					
Gross Assets	23,478,098	4,969,066	1,094,654		29,541,818
Accumulated Amortization	(3,969,726)		(608,881)	(2,579,643)	(7,158,250)
Net Book Value	19,508,372	4,969,066	485,773	(2,579,643)	22,383,568

Capital Asset Continuity Statements

* Asset retirements and other changes	2006 Balance	2007 Changes			2007 Balance
		Additions	Ret./Other *	Amortization	
1805-Land					
Gross Assets	242,769		(15,000)		227,769
Accumulated Amortization					
Net Book Value	242,769		(15,000)		227,769
1808-Buildings and Fixtures					
Gross Assets	6,517	2,443,787			2,450,304
Accumulated Amortization	(2,023)			(24,758)	(26,781)
Net Book Value	4,494	2,443,787		(24,758)	2,423,523
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	3,073,798	83,593			3,157,391
Accumulated Amortization	(862,166)			(143,364)	(1,005,530)
Net Book Value	2,211,632	83,593		(143,364)	2,151,861
1830-Poles, Towers and Fixtures					
Gross Assets	4,811,058	194,258			5,005,316
Accumulated Amortization	(1,094,849)			(217,108)	(1,311,957)
Net Book Value	3,716,209	194,258		(217,108)	3,693,359
1835-Overhead Conductors and Devices					
Gross Assets	6,734,937	622,265	(0)		7,357,202
Accumulated Amortization	(1,442,428)			(316,175)	(1,758,603)
Net Book Value	5,292,509	622,265	(0)	(316,175)	5,598,599
1840-Underground Conduit					
Gross Assets	2,094,546	389,798			2,484,344
Accumulated Amortization	(393,133)			(100,545)	(493,678)
Net Book Value	1,701,413	389,798		(100,545)	1,990,666
1845-Underground Conductors and Devices					
Gross Assets	5,563,155	695,407			6,258,562
Accumulated Amortization	(1,130,311)			(265,053)	(1,395,364)
Net Book Value	4,432,844	695,407		(265,053)	4,863,198

Capital Asset Continuity Statements

* Asset retirements and other changes	2006 Balance	2007 Changes			2007 Balance
		Additions	Ret./Other *	Amortization	
1850-Line Transformers					
Gross Assets	5,896,988	624,935			6,521,923
Accumulated Amortization	(1,143,249)			(276,309)	(1,419,558)
Net Book Value	4,753,739	624,935		(276,309)	5,102,365
1855-Services					
Gross Assets	2,727,052	277,646			3,004,698
Accumulated Amortization	(555,934)			(125,438)	(681,372)
Net Book Value	2,171,118	277,646		(125,438)	2,323,326
1860-Meters					
Gross Assets	2,302,027	136,217			2,438,244
Accumulated Amortization	(490,587)			(105,800)	(596,387)
Net Book Value	1,811,440	136,217		(105,800)	1,841,857
1915-Office Furniture and Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1920-Computer Equipment - Hardware					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1925-Computer Software					
Gross Assets	267,519				267,519
Accumulated Amortization	(209,098)			(53,503)	(262,601)
Net Book Value	58,421			(53,503)	4,918
1930-Transportation Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					

Capital Asset Continuity Statements

* Asset retirements and other changes

	2006 Balance	2007 Changes			2007 Balance
		Additions	Ret./Other *	Amortization	
1935-Stores Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1940-Tools, Shop and Garage Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1945-Measurement and Testing Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1950-Power Operated Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1955-Communication Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1960-Miscellaneous Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1975-Load Management Controls - Utility Premises					
Gross Assets	258,631				258,631
Accumulated Amortization	(258,631)				(258,631)
Net Book Value					

Capital Asset Continuity Statements

* Asset retirements and other changes

	2006 Balance	2007 Changes			2007 Balance
		Additions	Ret./Other *	Amortization	
1995-Contributions and Grants - Credit					
Gross Assets	(4,437,179)	(677,549)			(5,114,728)
Accumulated Amortization	424,159			194,413	618,572
Net Book Value	(4,013,020)	(677,549)		194,413	(4,496,156)
TOTAL					
Gross Assets	29,541,818	4,790,357	(15,000)		34,317,175
Accumulated Amortization	(7,158,250)			(1,433,640)	(8,591,890)
Net Book Value	22,383,568	4,790,357	(15,000)	(1,433,640)	25,725,285

Capital Asset Continuity Statements

* Asset retirements and other changes

	2007 Balance	2008 Changes			2008 Balance
		Additions	Ret./Other *	Amortization	
1805-Land					
Gross Assets	227,769				227,769
Accumulated Amortization					
Net Book Value	227,769				227,769
1808-Buildings and Fixtures					
Gross Assets	2,450,304				2,450,304
Accumulated Amortization	(26,781)			(49,196)	(75,977)
Net Book Value	2,423,523			(49,196)	2,374,327
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	3,157,391	430,785			3,588,176
Accumulated Amortization	(1,005,530)			(150,908)	(1,156,438)
Net Book Value	2,151,861	430,785		(150,908)	2,431,738
1830-Poles, Towers and Fixtures					
Gross Assets	5,005,316	225,045			5,230,361
Accumulated Amortization	(1,311,957)			(225,507)	(1,537,464)
Net Book Value	3,693,359	225,045		(225,507)	3,692,897
1835-Overhead Conductors and Devices					
Gross Assets	7,357,202	575,115			7,932,317
Accumulated Amortization	(1,758,603)			(340,166)	(2,098,769)
Net Book Value	5,598,599	575,115		(340,166)	5,833,548
1840-Underground Conduit					
Gross Assets	2,484,344	325,065			2,809,409
Accumulated Amortization	(493,678)			(114,859)	(608,537)
Net Book Value	1,990,666	325,065		(114,859)	2,200,872
1845-Underground Conductors and Devices					
Gross Assets	6,258,562	375,075			6,633,637
Accumulated Amortization	(1,395,364)			(286,479)	(1,681,843)
Net Book Value	4,863,198	375,075		(286,479)	4,951,794

Capital Asset Continuity Statements

* Asset retirements and other changes	2007 Balance	2008 Changes			2008 Balance
		Additions	Ret./Other *	Amortization	
1850-Line Transformers					
Gross Assets	6,521,923	200,040			6,721,963
Accumulated Amortization	(1,419,558)			(292,833)	(1,712,391)
Net Book Value	5,102,365	200,040		(292,833)	5,009,572
1855-Services					
Gross Assets	3,004,698	225,045			3,229,743
Accumulated Amortization	(681,372)			(135,011)	(816,383)
Net Book Value	2,323,326	225,045		(135,011)	2,413,360
1860-Meters					
Gross Assets	2,438,244	278,030			2,716,274
Accumulated Amortization	(596,387)			(114,116)	(710,503)
Net Book Value	1,841,857	278,030		(114,116)	2,005,771
1915-Office Furniture and Equipment					
Gross Assets		18,360	227,058		245,418
Accumulated Amortization			(115,088)	(18,172)	(133,260)
Net Book Value		18,360	111,970	(18,172)	112,158
1920-Computer Equipment - Hardware					
Gross Assets		38,700	357,474		396,174
Accumulated Amortization			(309,478)	(20,174)	(329,652)
Net Book Value		38,700	47,996	(20,174)	66,522
1925-Computer Software					
Gross Assets	267,519	37,800	409,571		714,890
Accumulated Amortization	(262,601)		(377,214)	(26,999)	(666,814)
Net Book Value	4,918	37,800	32,357	(26,999)	48,076
1930-Transportation Equipment					
Gross Assets		151,200	1,483,355		1,634,555
Accumulated Amortization			(775,843)	(127,177)	(903,020)
Net Book Value		151,200	707,512	(127,177)	731,535

Capital Asset Continuity Statements

* Asset retirements and other changes	2007 Balance	2008 Changes			2008 Balance
		Additions	Ret./Other *	Amortization	
1935-Stores Equipment					
Gross Assets			19,842		19,842
Accumulated Amortization			(5,038)	(1,776)	(6,814)
Net Book Value			14,804	(1,776)	13,028
1940-Tools, Shop and Garage Equipment					
Gross Assets		45,000	184,420		229,420
Accumulated Amortization			(126,776)	(10,793)	(137,569)
Net Book Value		45,000	57,644	(10,793)	91,851
1945-Measurement and Testing Equipment					
Gross Assets			51,482		51,482
Accumulated Amortization			(10,771)	(5,146)	(15,917)
Net Book Value			40,711	(5,146)	35,565
1950-Power Operated Equipment					
Gross Assets			30,011		30,011
Accumulated Amortization			(23,214)	(971)	(24,185)
Net Book Value			6,797	(971)	5,826
1955-Communication Equipment					
Gross Assets			99,188		99,188
Accumulated Amortization			(73,733)	(12,599)	(86,332)
Net Book Value			25,455	(12,599)	12,856
1960-Miscellaneous Equipment					
Gross Assets			27,970		27,970
Accumulated Amortization			(15,396)	(2,796)	(18,192)
Net Book Value			12,574	(2,796)	9,778
1975-Load Management Controls - Utility Premises					
Gross Assets	258,631				258,631
Accumulated Amortization	(258,631)				(258,631)
Net Book Value					

Capital Asset Continuity Statements

* Asset retirements and other changes

	2007 Balance	2008 Changes			2008 Balance
		Additions	Ret./Other *	Amortization	
1995-Contributions and Grants - Credit					
Gross Assets	(5,114,728)	(496,000)			(5,610,728)
Accumulated Amortization	618,572			215,222	833,794
Net Book Value	(4,496,156)	(496,000)		215,222	(4,776,934)
TOTAL					
Gross Assets	34,317,175	2,429,260	2,890,372		39,636,807
Accumulated Amortization	(8,591,890)		(1,832,552)	(1,720,456)	(12,144,898)
Net Book Value	25,725,285	2,429,260	1,057,820	(1,720,456)	27,491,909

Capital Asset Continuity Statements

* Asset retirements and other changes	2008 Balance	2009 Changes			2009 Balance
		Additions	Ret./Other *	Amortization	
1805-Land					
Gross Assets	227,769				227,769
Accumulated Amortization					
Net Book Value	227,769				227,769
1808-Buildings and Fixtures					
Gross Assets	2,450,304	16,000			2,466,304
Accumulated Amortization	(75,977)			(49,516)	(125,493)
Net Book Value	2,374,327	16,000		(49,516)	2,340,811
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	3,588,176	241,000			3,829,176
Accumulated Amortization	(1,156,438)			(162,392)	(1,318,830)
Net Book Value	2,431,738	241,000		(162,392)	2,510,346
1830-Poles, Towers and Fixtures					
Gross Assets	5,230,361	618,500			5,848,861
Accumulated Amortization	(1,537,464)			(242,357)	(1,779,821)
Net Book Value	3,692,897	618,500		(242,357)	4,069,040
1835-Overhead Conductors and Devices					
Gross Assets	7,932,317	843,200			8,775,517
Accumulated Amortization	(2,098,769)			(368,517)	(2,467,286)
Net Book Value	5,833,548	843,200		(368,517)	6,308,231
1840-Underground Conduit					
Gross Assets	2,809,409				2,809,409
Accumulated Amortization	(608,537)			(121,345)	(729,882)
Net Book Value	2,200,872			(121,345)	2,079,527
1845-Underground Conductors and Devices					
Gross Assets	6,633,637	505,500			7,139,137
Accumulated Amortization	(1,681,843)			(304,090)	(1,985,933)
Net Book Value	4,951,794	505,500		(304,090)	5,153,204

Capital Asset Continuity Statements

* Asset retirements and other changes	2008 Balance	2009 Changes			2009 Balance
		Additions	Ret./Other *	Amortization	
1850-Line Transformers					
Gross Assets	6,721,963	536,000			7,257,963
Accumulated Amortization	(1,712,391)			(307,538)	(2,019,929)
Net Book Value	5,009,572	536,000		(307,538)	5,238,034
1855-Services					
Gross Assets	3,229,743	35,500			3,265,243
Accumulated Amortization	(816,383)			(139,707)	(956,090)
Net Book Value	2,413,360	35,500		(139,707)	2,309,153
1860-Meters					
Gross Assets	2,716,274	30,000			2,746,274
Accumulated Amortization	(710,503)			(120,272)	(830,775)
Net Book Value	2,005,771	30,000		(120,272)	1,915,499
1915-Office Furniture and Equipment					
Gross Assets	245,418	2,000			247,418
Accumulated Amortization	(133,260)			(19,190)	(152,450)
Net Book Value	112,158	2,000		(19,190)	94,968
1920-Computer Equipment - Hardware					
Gross Assets	396,174	11,800			407,974
Accumulated Amortization	(329,652)			(23,959)	(353,611)
Net Book Value	66,522	11,800		(23,959)	54,363
1925-Computer Software					
Gross Assets	714,890	35,400			750,290
Accumulated Amortization	(666,814)			(25,157)	(691,971)
Net Book Value	48,076	35,400		(25,157)	58,319
1930-Transportation Equipment					
Gross Assets	1,634,555	30,000	(10,000)		1,654,555
Accumulated Amortization	(903,020)		10,000	(138,502)	(1,031,522)
Net Book Value	731,535	30,000		(138,502)	623,033

Capital Asset Continuity Statements

* Asset retirements and other changes

	2008 Balance	2009 Changes			2009 Balance
		Additions	Ret./Other *	Amortization	
1935-Stores Equipment					
Gross Assets	19,842	72,500			92,342
Accumulated Amortization	(6,814)			(5,401)	(12,215)
Net Book Value	13,028	72,500		(5,401)	80,127
1940-Tools, Shop and Garage Equipment					
Gross Assets	229,420	45,000			274,420
Accumulated Amortization	(137,569)			(15,293)	(152,862)
Net Book Value	91,851	45,000		(15,293)	121,558
1945-Measurement and Testing Equipment					
Gross Assets	51,482				51,482
Accumulated Amortization	(15,917)			(5,146)	(21,063)
Net Book Value	35,565			(5,146)	30,419
1950-Power Operated Equipment					
Gross Assets	30,011	42,000			72,011
Accumulated Amortization	(24,185)			(3,071)	(27,256)
Net Book Value	5,826	42,000		(3,071)	44,755
1955-Communication Equipment					
Gross Assets	99,188				99,188
Accumulated Amortization	(86,332)			(10,286)	(96,618)
Net Book Value	12,856			(10,286)	2,570
1960-Miscellaneous Equipment					
Gross Assets	27,970				27,970
Accumulated Amortization	(18,192)			(2,796)	(20,988)
Net Book Value	9,778			(2,796)	6,982
1975-Load Management Controls - Utility Premises					
Gross Assets	258,631				258,631
Accumulated Amortization	(258,631)				(258,631)
Net Book Value					

Capital Asset Continuity Statements

* Asset retirements and other changes	2008 Balance	2009 Changes			2009 Balance
		Additions	Ret./Other *	Amortization	
1995-Contributions and Grants - Credit					
Gross Assets	(5,610,728)	(484,000)			(6,094,728)
Accumulated Amortization	833,794			234,822	1,068,616
Net Book Value	(4,776,934)	(484,000)		234,822	(5,026,112)
TOTAL					
Gross Assets	39,636,807	2,580,400	(10,000)		42,207,207
Accumulated Amortization	(12,144,898)		10,000	(1,829,713)	(13,964,611)
Net Book Value	27,491,909	2,580,400		(1,829,713)	28,242,596

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Gross Assets Table

The following attachment is the Gross Assets Table.

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B1 Gross Capital Assets

Gross Capital Asset Account	2006 EDR Approved	Variance to 2006 Actual		
		Additions	Retirements / Other	Ending Balance
1805-Land	107,769	135,000		242,769
1808-Buildings and Fixtures	6,517			6,517
1820-Distribution Station Equipment - Normally Primary below 50 kV	3,073,798			3,073,798
1830-Poles, Towers and Fixtures	3,892,678	769,162	149,218	4,811,058
1835-Overhead Conductors and Devices	5,137,278	1,558,013	39,646	6,734,937
1840-Underground Conduit	1,315,937	595,180	183,429	2,094,546
1845-Underground Conductors and Devices	3,444,539	1,261,952	856,664	5,563,155
1850-Line Transformers	3,824,513	2,211,021	(138,546)	5,896,988
1855-Services	2,069,198	517,571	140,283	2,727,052
1860-Meters	1,866,214	363,794	72,019	2,302,027
1915-Office Furniture and Equipment				
1920-Computer Equipment - Hardware				
1925-Computer Software	255,224		12,295	267,519
1930-Transportation Equipment				
1935-Stores Equipment				
1940-Tools, Shop and Garage Equipment				
1945-Measurement and Testing Equipment				
1950-Power Operated Equipment				
1955-Communication Equipment				
1960-Miscellaneous Equipment				
1975-Load Management Controls - Utility Premises	258,630		1	258,631
1995-Contributions and Grants - Credit	(1,774,197)	(2,442,627)	(220,355)	(4,437,179)
TOTAL	23,478,098	4,969,066	1,094,654	29,541,818

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B1 Gross Capital Assets

Gross Capital Asset Account	2006 Actual Ending Balance	2007 Actual		
		Additions	Retirements / Other	Ending Balance
1805-Land	242,769		(15,000)	227,769
1808-Buildings and Fixtures	6,517	2,443,787		2,450,304
1820-Distribution Station Equipment - Normally Primary below 50 kV	3,073,798	83,593		3,157,391
1830-Poles, Towers and Fixtures	4,811,058	194,258		5,005,316
1835-Overhead Conductors and Devices	6,734,937	622,265	(0)	7,357,202
1840-Underground Conduit	2,094,546	389,798		2,484,344
1845-Underground Conductors and Devices	5,563,155	695,407		6,258,562
1850-Line Transformers	5,896,988	624,935		6,521,923
1855-Services	2,727,052	277,646		3,004,698
1860-Meters	2,302,027	136,217		2,438,244
1915-Office Furniture and Equipment				
1920-Computer Equipment - Hardware				
1925-Computer Software	267,519			267,519
1930-Transportation Equipment				
1935-Stores Equipment				
1940-Tools, Shop and Garage Equipment				
1945-Measurement and Testing Equipment				
1950-Power Operated Equipment				
1955-Communication Equipment				
1960-Miscellaneous Equipment				
1975-Load Management Controls - Utility Premises	258,631			258,631
1995-Contributions and Grants - Credit	(4,437,179)	(677,549)		(5,114,728)
TOTAL	29,541,818	4,790,357	(15,000)	34,317,175

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B1 Gross Capital Assets

Gross Capital Asset Account	2007 Actual Ending Balance	2008 Projection		
		Additions	Retirements / Other	Ending Balance
1805-Land	227,769			227,769
1808-Buildings and Fixtures	2,450,304			2,450,304
1820-Distribution Station Equipment - Normally Primary below 50 kV	3,157,391	430,785		3,588,176
1830-Poles, Towers and Fixtures	5,005,316	225,045		5,230,361
1835-Overhead Conductors and Devices	7,357,202	575,115		7,932,317
1840-Underground Conduit	2,484,344	325,065		2,809,409
1845-Underground Conductors and Devices	6,258,562	375,075		6,633,637
1850-Line Transformers	6,521,923	200,040		6,721,963
1855-Services	3,004,698	225,045		3,229,743
1860-Meters	2,438,244	278,030		2,716,274
1915-Office Furniture and Equipment		18,360	227,058	245,418
1920-Computer Equipment - Hardware		38,700	357,474	396,174
1925-Computer Software	267,519	37,800	409,571	714,890
1930-Transportation Equipment		151,200	1,483,355	1,634,555
1935-Stores Equipment			19,842	19,842
1940-Tools, Shop and Garage Equipment		45,000	184,420	229,420
1945-Measurement and Testing Equipment			51,482	51,482
1950-Power Operated Equipment			30,011	30,011
1955-Communication Equipment			99,188	99,188
1960-Miscellaneous Equipment			27,970	27,970
1975-Load Management Controls - Utility Premises	258,631			258,631
1995-Contributions and Grants - Credit	(5,114,728)	(496,000)		(5,610,728)
TOTAL	34,317,175	2,429,260	2,890,372	39,636,807

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B1 Gross Capital Assets

Gross Capital Asset Account	2008 Projection Ending Balance	2009 Projection		
		Additions	Retirements / Other	Ending Balance
1805-Land	227,769			227,769
1808-Buildings and Fixtures	2,450,304	16,000		2,466,304
1820-Distribution Station Equipment - Normally Primary below 50 kV	3,588,176	241,000		3,829,176
1830-Poles, Towers and Fixtures	5,230,361	618,500		5,848,861
1835-Overhead Conductors and Devices	7,932,317	843,200		8,775,517
1840-Underground Conduit	2,809,409			2,809,409
1845-Underground Conductors and Devices	6,633,637	505,500		7,139,137
1850-Line Transformers	6,721,963	536,000		7,257,963
1855-Services	3,229,743	35,500		3,265,243
1860-Meters	2,716,274	30,000		2,746,274
1915-Office Furniture and Equipment	245,418	2,000		247,418
1920-Computer Equipment - Hardware	396,174	11,800		407,974
1925-Computer Software	714,890	35,400		750,290
1930-Transportation Equipment	1,634,555	30,000	(10,000)	1,654,555
1935-Stores Equipment	19,842	72,500		92,342
1940-Tools, Shop and Garage Equipment	229,420	45,000		274,420
1945-Measurement and Testing Equipment	51,482			51,482
1950-Power Operated Equipment	30,011	42,000		72,011
1955-Communication Equipment	99,188			99,188
1960-Miscellaneous Equipment	27,970			27,970
1975-Load Management Controls - Utility Premises	258,631			258,631
1995-Contributions and Grants - Credit	(5,610,728)	(484,000)		(6,094,728)
TOTAL	39,636,807	2,580,400	(10,000)	42,207,207

Materiality/Variance Analysis on Gross Assets

The materiality thresholds for gross assets were calculated as follows

Total Gross Assets	2009 Test to 2008 Bridge	2008 Bridge to 2007 Actual	2007 Actual to 2006 Actual	2006 Actual to 2006 EDR
Percent	1%	1%	1%	1%
Threshold	\$274,229	\$257,253	\$223,836	\$195,084

2009 Test Year vs. 2008 Bridge Year

Preamble:

Variances in gross asset accounts for the 2009 Test Year vs. the 2008 Bridge Year are primarily attributable to three programs / projects.

Wood Pole Replacement Program: Predecessor utilities did not have a defective wood pole replacement program. Many poles are in excess of 40 years old. There is a risk of the poles falling from high winds and ice loading, posing a significant hazard to the public. The work is in various communities and does not represent significant pole line rebuild, but replacement of individual poles.

Explanation: Every year Westario Power replaces defective wood poles (described above). Further, the bulk of Westario Power's distribution is overhead, and plant rebuild for feeder reinforcement is another annual program. Work will be distributed over 1830, 1835, 1850, and 1855. WPI's Defective Pole Replacement program is discussed at Exhibit 2, Tab 3, Schedule 1, section 1.3.1.

#6 Copper Replacement Program: In the past #6 Copper primary wire was an inexpensive solution for extending power lines to areas with small energy demands. These areas are now experiencing load growth and feeder extensions off the #6 primary wire. The wire has grown brittle and is undersized for the average load.

Explanation: This wire type poses a public and worker safety issue should the wire break and fall. Because of the smallness of the wire, the protection equipment at the substation does not sense the fault and does not operate to isolate the line. Work will be distributed over 1830, 1835, 1850, and 1855. WPI's #6 Copper Replacement program is discussed at Exhibit 2, Tab 3, Schedule 1, section 1.2.2.

Pole Line Rebuild Projects: These projects are identified for inclusion as they serve the purpose of increasing reliability, increasing feeder capacity or the condition of the line. In addition the severe impact of its failure on customer interruption makes the work necessary.

Explanation: Usually, pole line work is a particular project serving a particular need. In 2009 feeder rebuilds are planned for back-lot replacement in Hanover, and pole-line replacements in Kincardine, Teeswater and Port Elgin. Work will be distributed over 1830, 1835, 1850, and 1855. Occasionally underground accounts are transacted. WPI's Pole Line Replacement program is discussed at Exhibit 2, Tab 3, Schedule 1, section 1.2.1.

Expenditures by Asset Account

Account Description	2009 Test	2008 Bridge	Variance in \$	% change
1808-Buildings and Fixtures	2,466,304	2,450,304	16,000	0.7%

Installation of yard lighting for the safety of the employees and added security for inventory items stored in the gated yard.

Account Description	2009 Test	2008 Bridge	Variance in \$	% change
1820-Distribution Station Equipment – Normally Primary below 50kV	3,829,176	3,588,176	241,000	6.7%

Proposed substation equipment replacement and strategic spare acquisitions:

Acquire a spare transformer for Harriston MS1 substation in 2008; and will be installed in 2009 as there is no backup supply.

Acquire reclosers for Wingham MS1 substation and replace primary fusing.

Account Description	2009 Test	2008 Bridge	Variance in \$	% change
1830-Poles, Towers and Fixtures	5,848,861	5,230,361	618,500	11.8%

Proposed capital work in multiple project groups.

- Pole replacement in conjunction with the #6 Copper Replacement program for public and worker safety.
- Wood Pole Replacements in various locations.
- Pole replacement in conjunction with line rebuild for feeder upgrades in Kincardine, Port Elgin and Teeswater. Rear-lot pole-line replacement planned for Hanover.

Account Description	2009 Test	2008 Bridge	Variance in \$	% change
1835-Overhead Conductors and Devices	8,775,517	7,932,317	843,200	10.6%

Proposed capital work in multiple project groups.

- Conductor replacement in conjunction with #6 Copper replacement program for public and worker safety.
- Conductor replacement in conjunction with wood pole replacements in various locations.
- Conductor replacement in conjunction with line rebuild for feeder upgrades in Kincardine, Port Elgin and Teeswater. Rear-lot pole-line replacement planned for Hanover.

Account Description	2009 Test	2008 Bridge	Variance in \$	% change
1845-Underground Conductors and Devices	7,139,137	6,633,637	505,500	7.6%

Proposed capital works in multiple project groups.

- Installing ground grids at pad mount transformers with no ground grids for public and worker safety and rectify an electrical code violation.
- Underground subdivisions.
- Underground commercial customers.

Account Description	2009 Test	2008 Bridge	Variance in \$	% change
1850-Line Transformers	7,257,963	6,721,963	536,000	8.0%

Proposed capital works in multiple project groups.

- Transformers in conjunctions with #6 Copper Replacement program for public and work safety.
- Transformers in conjunctions with Wood Pole Replacements in various locations.
- Transformers in conjunctions with Line rebuild for feeder upgrades in Kincardine, Port Elgin and Teeswater. Rear-lot pole-line replacement planned for Hanover.
- Transformers in conjunctions with new subdivisions.
- Transformers in conjunctions with new commercial customers.

Account Description	2009 Test	2008 Bridge	Variance in \$	% change
1855-Services	3,265,243	3,229,743	35,500	1.1%

New service connections, various locations.

Account Description	2009 Test	2008 Bridge	Variance in \$	% change
1860-Meters	2,746,274	2,716,274	30,000	1.1%

New meters to replace old thermal demand meters that cannot be recertified, or are too costly to recertify.

Account Description	2009 Test	2008 Bridge	Variance in \$	% change
1915-Office Furniture and Equipment	247,418	245,418	2,000	0.8%

Additional equipment required for clerical staff.

Account Description	2009 Test	2008 Bridge	Variance in \$	% change
1920-Computer Equipment, Hardware	407,974	396,174	11,800	3.0%

Replacement of computer desktops for clerical staff that are in excess of three years old.

Account Description	2009 Test	2008 Bridge	Variance in \$	% change
1925-Computation Equipment, Software	750,290	714,890	35,400	5.0%

Outage management software and implementation costs. Allows tracing those feeders with poorest outage quality indicators.

WPI predominantly uses steel poles in its overhead pole-line construction. Pole class calculator software for confirming strength compliance.

Account Description	2009 Test	2008 Bridge	Variance in \$	% change
1930-Transportation Equipment	1,654,555	1,634,555	20,000	1.2%

Replacement of 10-year old pick up truck with a new pick up truck, less the gross capital cost of the older vehicle. For a more detailed description of this expense, please refer to Exhibit 2, Tab 3, Schedule 1, Section 3.2.

Account Description	2009 Test	2008 Bridge	Variance in \$	% change
1935-Store Equipment	92,342	19,842	72,500	365.4%

Replace fork lift, vintage 1975, with new forklift. For a more detailed description of this expense, please refer to Exhibit 2, Tab 3, Schedule 1, Section 3.4.

Account Description	2009 Test	2008 Bridge	Variance in \$	% change
1940-Tools, Shop and Garage Equipment	274,420	229,420	45,000	19.6%

Purchase new and replace old "large tools", including cluster grounds, rubber coverup, etc. These items usually have an individual value of more than \$1000 each.

Account Description	2009 Test	2008 Bridge	Variance in \$	% change
1950-Power Operated Equipment	72,011	30,011	42,000	139.9%

Replace brush chipper, vintage 1994. For a more detailed description of this expense, please refer to Exhibit 2, Tab 3, Schedule 1, Section 3.5.

2008 Budgeted vs. 2007 Actual

Preamble:

Variances in gross asset accounts for the 2008 Bridge Year vs. 2007 Actual are primarily attributable to the following programs / projects.

Wood Pole Replacement Program: Predecessor utilities did not have a defective wood pole replacement program. Many poles are in excess of 40 years old. There is a risk of the poles falling from high winds and ice loading, posing a significant hazard to the public. The work is in various communities and does not represent significant pole line rebuild, but replacement of individual poles.

Explanation: Every year Westario Power replaces defective wood poles (described above). Further, the bulk of Westario Power's distribution is overhead, and plant rebuild for feeder reinforcement is another annual program. Work will be distributed over 1830, 1835, 1850, and 1855.

Porcelain Insulator Replacement Program: Porcelain insulators are not a problem unique to Westario Power Inc. These have widespread use in the province. Because of age and original manufacturing techniques these insulators break off at the base and drop energized conductors onto adjacent feeders and grounded equipment.

Explanation: Westario Power replaces porcelain insulators annually. Broken insulators drop energized conductors onto ground equipment causing widespread system outages. Work is mostly in 1835. Approximately 1,050 insulators were replaced in 2007 over the planned four

1 projects. These projects were completed in 2007 and resulted in the increased expenditures.
2 The per unit cost to replace insulators varies significantly on the installation particulars, such as
3 pole framing, existence of adjacent circuits, pole location such as the road right of way or back
4 yard, and other factors.

5
6 **#6 Copper Replacement Program:** In the past #6 Copper primary wire was an inexpensive
7 solution for extending power lines to areas with small energy demands. These areas are now
8 experiencing load growth and feeder extensions off the #6 primary wire. The wire has grown
9 brittle and is undersized for the average load.

10
11 Explanation: This wire type poses a public and worker safety issue should the wire break and
12 fall. Because of the smallness of the wire, the protection equipment at the substation does not
13 sense the fault and does not operate to isolate the line. Work will be distributed over 1830,
14 1835, 1850, and 1855.

15
16 **5kV Cable Replacement Program:** In the past 5kV butyl rubber cable and "Pole Trans"
17 transformers were used to service residential neighborhoods. The 5 kV cable is direct buried
18 and is failing as it has surpassed its 30 year lifespan. The Pole Tran transformers are heavily
19 loaded and extremely congested, posing worker safety issues. The cable replacement projects
20 for 2007 were to improve reliability in areas with aged infrastructure. The cable replacement
21 plan for each year is developed in advance during the budgeting process. Failures and outages
22 that occur throughout the year are reviewed to determine if changes to the program are
23 warranted to address areas with declining reliability.

24
25 Explanation: Emergency directional boring is expensive and, depending on the season, may not
26 be practical. Temporary poles have been built to restore power. New conduit is bored into place
27 and new cables are pulled through the conduits. The Pole Tran transformers are replaced with
28 new pad mount transformers, with sufficient capacity and accessibility.

29

1 **Pole Line Rebuild Projects:** These projects are identified for inclusion as they serve the
2 purpose of increasing reliability, increasing feeder capacity or the condition of the line. In
3 addition the severe impact of its failure on customer interruption make the work necessary.

4 Explanation: Usually, pole line work is a particular project serving a particular need. In 2008,
5 two pole-line projects were undertaken, one to increase feeder capability between two
6 substation and the other to rebuild a decaying pole line carrying the 44kV feeder to a substation.
7 Work will be distributed over 1830, 1835, 1850, and 1855.

8
9 **Defective Transformer Foundations:** Fiberglass transformer foundations were once in vogue
10 by utilities. They were inexpensive, lightweight, and easy to manipulate. Fiberglass transformer
11 foundations are decaying and the transformers are now sitting askew. As the sidewalls decay,
12 the high voltage cables become accessible exposing the public to potential contact hazards.

13
14 Explanation: In time the fiberglass has decayed and the overbearing weight of the transformers
15 is accelerating the wall collapse. The energized voltage cables are accessible, exposing the
16 public to potential contact hazards. The fiberglass foundations will be replaced with precast
17 concrete foundations.

18
19 **Trench Box Replacement:** The former utilities used 24-inch and 30-inch concrete pipe as
20 junction boxes for secondary connections. The 24-inch and 30-inch concrete pipe were laid
21 sideways, and the openings were enclosed by merely placing a concrete patio stone over the
22 opening. The drain pipes are now decaying and the patio stones are crumbling.

23
24 Explanation: The energized voltage cables are accessible, exposing the public to potential
25 contact hazards. The project will replace substandard junction boxes with secure precast
26 junction boxes.

27
28 In addition to the above projects, the Ontario Energy Board issued a decision and order (File
29 #EB02007-0103) on July 13, 2007 for Westario Power Inc. to amalgamate with Westario Power
30 Holdings Inc. and Westario Power Services Inc. The amalgamation between Westario Power
31 Inc., Westario Power Holdings Inc. and Westario Power Services Inc. became effective January

1, 2008. As a result of the amalgamation; approximately \$2,970,372 of gross assets were transferred from Westario Power Services Inc. to Westario Power Inc. at a net book value of \$1,057,821 (gross cost less accumulated depreciation). Listed below is a summary of the assets transferred that are used in the day to day operations of Westario Power Inc.

		Original Cost	Accumulated Amortization	Net Book Value
1915	Office Furniture and Equipment	227,058	115,088	111,970
1920	Computer Equipment – Hardware	357,474	309,478	47,996
1925	Computer Software	409,571	377,213	32,358
1930	Transportation Equipment	1,563,355	855,843	707,512
1935	Stores Equipment	19,842	5,038	14,804
1940	Tools, Shop and Garage Equipment	184,420	126,776	57,644
1945	Measurement and Testing Equipment	51,481	10,770	40,711
1950	Power Operated Equipment	30,010	23,213	6,797
1955	Communication Equipment	99,187	73,732	25,455
1960	Miscellaneous Equipment	27,970	15,396	12,574
	Total	2,970,372	1,912,552	1,057,821

Expenditures by Asset Account

Account Description	2008 Bridge	2007 Actual	Variance in \$	% change
1820-Distribution Station Equipment - Normally Primary below 50 kV	3,588,176	3,157,391	430,785	13.6%

Explanation:

- Palmerston MS1 ground grid replacement: The ground grid has been found to be inadequate; and a code-compliant ground grid is required at the substation. This will improve the ability of the substation to withstand ground faults.
- Hanover MS2 substation cable replacements: The existing cable is aged and deteriorating.
- Palmerston MS1 recloser replacement: The existing reclosers are mismatched and cannot provide back-up to adjacent feeders. New long-life vacuum-technology reclosers will be installed to provide feeder switching and improve safety.
- Harriston MS1 substation transformer: The Town of Harriston is the only Westario Power municipality supplied by a 13.8/8kV distribution system. The one and only substation has no backup supply. Adjacent Hydro One feeders are not the same voltage. The substation is supplied from Hydro One 44 kV sub-transmission; and a 44-13.8/8kV substation is an unusual arrangement. Spare substations in this configuration are difficult to find. A spare will be acquired in 2008 and stored at the substation site.
- Walkerton MS1 substation transformer. Dissolved gas analysis indicates that the paper insulation is breaking down. The transformer is more than 40 years old. Attempts to slow the deterioration are costly and have not been effective. A new substation transformer is being acquired and installed in 2008.

Account Description	2008 Bridge	2007 Actual	Variance in \$	% change
1830 – Poles, Towers and Fixtures	5,230,361	5,005,316	225,045	4.5%

Proposed capital work in multiple projects groups:

- Pole replacements in conjunction with Porcelain insulator replacements.
- Pole replacements in conjunction with Wood pole replacements.
- Pole replacements in conjunction with Pole -line replacement projects.
- Pole replacements in conjunction with #6 Copper wire replacement program for worker and public safety.

Account Description	2008 Bridge	2007 Actual	Variance in \$	% change
1835-Overhead Conductors and Devices	7,932,317	7,357,202	575,115	7.8%

Proposed capital work in multiple projects groups:

- Porcelain insulator replacements.
- Wood pole replacements.
- Pole -line replacement projects.
- #6 Copper wire replacement program for worker and public safety.

Account Description	2008 Bridge	2007 Actual	Variance in \$	% change
1840-Underground Conduit	2,809,409	2,484,344	325,065	13.1%

Proposed capital work in multiple projects groups:

- Underground conduit installation in conjunction with the deteriorating 5kV cable replacement project.
- Defective fiberglass transformer foundation replacements.
- Defective trench box replacement.

Account Description	2008 Bridge	2007 Actual	Variance in \$	% change
1845-Underground Conductors and Devices	6,633,637	6,258,562	375,075	6.0%

Proposed capital work in multiple projects groups:

- Underground primary and secondary cable installation for deteriorating the 5kV cable replacement project.
- Subdivisions as required to fulfill customer demand.
- Commercial services as required to fulfill customer demand.

Account Description	2008 Bridge	2007 Actual	Variance in \$	% change
1850-Line Transformers	6,721,963	6,521,923	200,040	3.1%

Proposed capital work in multiple projects groups:

- Transformer replacements in conjunction with Porcelain insulator replacements.
- Transformer replacements in conjunction with Wood pole replacements.
- Transformer replacements in conjunction with Pole -line replacement projects.
- Transformer replacements in conjunction with #6 Copper wire replacement program for worker and public safety.
- Transformers in new subdivisions.
- Transformers for new commercial customers.

Account Description	2008 Bridge	2007 Actual	Variance in \$	% change
1855-Services	3,229,743	3,004,698	225,045	7.5%

Proposed capital work in multiple projects groups:

- Service upgrades and work on existing services.
- New subdivisions.
- New commercial customers.
- In-fill lots outside of subdivisions.

Account Description	2008 Bridge	2007 Actual	Variance in \$	% change
1860-Meters	2,716,274	2,438,244	278,030	11.4%

Proposed meter work in various locations:

- Westario Power has identified approx 40 installations that require complete meter rebuilds. The existing meters cannot be recertified and instrument transformers are of dubious vintage.
- New electronic multi-function meters will be acquired and old thermal meters will be retired.

Account Description	2008 Bridge	2007 Actual	Variance in \$	% change
1915-Office Furniture and Equipment	245,418	0	245,418	100.0%

As a result of the amalgamation of Westario Power Inc., Westario Power Holdings Inc. and Westario Power Services Inc.; approximately \$225,000 (91.7%) of assets in the above class were transferred from Westario Power Services Inc. to Westario Power Inc. The balance of the asset class includes additions for office furniture, and storage units.

Account Description	2008 Bridge	2007 Actual	Variance in \$	% change
1920-Computer Equipment – Hardware	396,174	0	396,174	100%

As a result of the amalgamation of Westario Power Inc., Westario Power Holdings Inc. and Westario Power Services Inc.; approximately \$358,000 (90.4%) of assets in the above class were transferred from Westario Power Services Inc. to Westario Power Inc. The balance of the asset class includes additional laptops for field crews to access maps and collect field data, and replacement of desktop computers for clerical staff.

Account Description	2008 Bridge	2007 Actual	Variance in \$	% change
1925-Computer Software	714,890	267,519	447,371	167.2%

As a result of the amalgamation of Westario Power Inc., Westario Power Holdings Inc. and Westario Power Services Inc.; approximately \$410,000 (91.7%) of the variance in the above

class was transferred from Westario Power Services Inc. to Westario Power Inc. The balance of the variance is for additional software for field laptops, used in electronic mapping.

Account Description	2008 Bridge	2007 Actual	Variance in \$	% change
1930-Transportation Equipment	1,634,555	0	1,634,555	100%

As a result of the amalgamation of Westario Power Inc., Westario Power Holdings Inc. and Westario Power Services Inc.; approximately \$1,563,000 (95.7%) of the variance in the above class was transferred from Westario Power Services Inc. to Westario Power Inc. The balance of the asset class includes replacement of a small utility vehicle, and two 4X4 1/2 ton pick-up trucks; all of which are in excess of ten years old.

Account Description	2008 Bridge	2007 Actual	Variance in \$	% change
1935-Store Equipment	19,482	0	19,482	100%

As a result of the amalgamation of Westario Power Inc., Westario Power Holdings Inc. and Westario Power Services Inc.; all assets in the above class were transferred from Westario Power Services Inc. to Westario Power Inc.

Account Description	2008 Bridge	2007 Actual	Variance in \$	% change
1940-Tools, Shop and Garage Equipment	229,420	0	229,420	100%

As a result of the amalgamation of Westario Power Inc., Westario Power Holdings Inc. and Westario Power Services Inc.; approximately \$185,000 (80.6%) of the variance in the above class was transferred from Westario Power Services Inc. to Westario Power Inc. The balance of the variance in the above asset class is for additional large tools.

Account Description	2008 Bridge	2007 Actual	Variance in \$	% change
1945-Measurement and Testing Equipment	51,482	0	51,482	100%

As a result of the amalgamation of Westario Power Inc., Westario Power Holdings Inc. and Westario Power Services Inc.; all assets in the above class were transferred from Westario Power Services Inc. to Westario Power Inc.

Account Description	2008 Bridge	2007 Actual	Variance in \$	% change
1950-Power Operated Equipment	30,011	0	30,011	100%

As a result of the amalgamation of Westario Power Inc., Westario Power Holdings Inc. and Westario Power Services Inc.; all assets in the above class were transferred from Westario Power Services Inc. to Westario Power Inc.

Account Description	2008 Bridge	2007 Actual	Variance in \$	% change
1955-Communication Equipment	99,188	0	99,188	100%

As a result of the amalgamation of Westario Power Inc., Westario Power Holdings Inc. and Westario Power Services Inc.; all assets in the above class were transferred from Westario Power Services Inc. to Westario Power Inc.

Account Description	2008 Bridge	2007 Actual	Variance in \$	% change
1960-Miscellaneous Equipment	27,970	0	27,970	100%

As a result of the amalgamation of Westario Power Inc., Westario Power Holdings Inc. and Westario Power Services Inc.; all assets in the above class were transferred from Westario Power Services Inc. to Westario Power Inc.

2007 Actual VS 2006 Actual

Preamble:

Variances in gross asset accounts for the 2007 Actual vs. 2006 Actual are primarily attributable to the following programs / projects.

Wood Pole Replacement Program: Predecessor utilities did not have a defective wood pole replacement program. Many poles are in excess of 40 years old. There is a risk of the poles falling from high winds and ice loading, posing a significant hazard to the public. The work is in

1 various communities and does not represent significant pole line rebuilt, but replacement of
2 individual poles.

3
4 Explanation: Every year Westario Power replaces defective wood poles (described above).
5 Further, the bulk of Westario Power's distribution is overhead, and plant rebuild for feeder
6 reinforcement is another annual program. Work was distributed over accounts 1830, 1835,
7 1850, and 1855.

8
9 **Porcelain Insulator Replacement Program:** Porcelain insulators are not a problem unique to
10 Westario Power Inc. These have widespread use in the province. Because of age and original
11 manufacturing techniques, these insulators break off at the base and drop energized conductors
12 onto adjacent feeders and grounded equipment.

13
14 Explanation: Westario Power replaces porcelain insulators annually. Broken insulators drop
15 energized conductors onto ground equipment causing widespread system outages. Work was
16 mostly in account 1835.

17
18 **#6 Copper Replacement Program:** In the past #6 Copper primary wire was an inexpensive
19 solution for extending power lines to areas with small energy demands. These areas are now
20 experiencing load growth and feeder extensions off the #6 primary wire. The wire has grown
21 brittle and is undersized for the average load.

22
23 Explanation: This wire type poses a public and worker safety issue should the wire break and
24 fall. Because of the smallness of the wire, the protection equipment at the substation does not
25 sense the fault and does not operate to isolate the line. Work was distributed over accounts
26 1830, 1835, 1850, and 1855.

27
28 **5kV Cable Replacement Program:** In the past 5kV butyl rubber cable and "Pole Trans"
29 transformers we used to service residential neighborhoods. The 5 kV cable is direct buried and
30 is failing as it has surpassed its 30 year lifespan. The Pole Tran transformers are heavily
31 loaded and extremely congested, posing worker safety issues.

Explanation: Emergency directional boring is expensive and, depending on the season, may not be practical. Temporary poles have been built to restore power. New conduit is bored into place and new cables are pulled through the conduits. The Pole Tran transformers are replaced with new pad mount transformers, with sufficient capacity and accessibility.

Pole Line Rebuild Projects: These projects are identified for inclusion as they serve the purpose of increasing reliability, increasing feeder capacity or the condition of the line, and the severe impact of its failure on customer interruption, make the work necessary.

Explanation: Usually, pole line work is a particular project serving a particular need. In 2007, two pole-line projects were undertaken, one to increase feeder capability between two substations and the other to rebuild a decaying pole line carrying the 44kV feeder to a substation. Work was distributed over accounts 1830, 1835, 1850, and 1855.

Expenditures by Asset Account

Account Description	2007 Actual	2006 Actual	Variance in \$	% change
1808-Buildings and Fixtures	2,450,304	6,517	2,443,787	37498.6%

The variance in the above account is as a direct result of the new operating facility that was built in 2007. Please see Exhibit 2, Tab 3, Schedule 6 for the further information.

Account Description	2007 Actual	2006 Actual	Variance in \$	% change
1820-Distribution Station Equipment - Normally Primary below 50 kV	3,157,391	3,073,798	83,583	2.7%

Capital work to replace a substation transformer with our strategic spare. The removed transformer was found to be defective. The defective was shipped for repair and rebuild and is currently designated as a strategic spare.

Account Description	2007 Actual	2006 Actual	Variance in \$	% change
1830 – Poles, Towers and Fixtures	5,005,316	4,811,058	194,258	4.0%

Capital work in multiple projects groups:

- Pole, tower and fixture replacement in conjunction with porcelain insulator replacements.
- Pole, tower and fixture replacement in conjunction with pole-line rebuild and wood pole replacement projects.
- Pole, tower and fixture replacement in conjunction with requests by municipalities to relocate distribution plant based on municipal works.

Account Description	2007 Actual	2006 Actual	Variance in \$	% change
1835-Overhead Conductors and Devices	7,357,202	6,734,937	622,265	9.2%

Capital work in multiple projects groups:

- Conductor and device replacement in conjunction with porcelain insulator replacements.
- Conductor and device replacement in conjunction with pole-line rebuild and wood pole replacement projects.
- Conductor and device replacement in conjunction with requests by municipalities to relocate distribution plant based on municipal works.

Account Description	2007 Actual	2006 Actual	Variance in \$	% change
1840-Underground Conduit	2,484,344	2,094,546	389,798	18.6%

Capital work in multiple projects groups:

- Underground conduit in conjunction with the 5 kV cable replacement program.
- Underground conduit in conjunction with both non-subdivision conduit work to service new underground customers; and subdivision work.

Account Description	2007 Actual	2006 Actual	Variance in \$	% change
1845-Underground Conductors and Devices	6,258,562	5,563,155	695,407	12.5%

Capital work in multiple projects groups:

- Underground conductors and devices in conjunction with the 5 kV cable replacement program.
- Underground conductors and devices in subdivisions.

Account Description	2007 Actual	2006 Actual	Variance in \$	% change
1850-Line Transformers	6,521,923	5,896,988	624,935	10.6%

Capital work in multiple projects groups:

- Transformer replacement in conjunction with the 5kV cable replacement program.
- Transformer replacement in conjunction with pole line rebuilds.
- Balance as the large number of new commercial pad mount service added in 2007.

Account Description	2007 Actual	2006 Actual	Variance in \$	% change
1855-Services	3,004,698	2,727,052	277,646	10.2%

Capital work in multiple projects groups:

- Work on services in conjunction with the 5 kV cable replacement programs, and pole-line rebuild programs

Account Description	2007 Actual	2006 Actual	Variance in \$	% change
1860-Meters	2,438,244	2,302,027	136,217	5.9%

Capital work to fulfill regulatory requirements for wholesale meter points.

2006 Actual VS 2006 EDR Approved

The 2006 EDR Approved was based on the average of 2004 and 2003 actuals. As a result, the variance between 2006 Actual and the 2006 EDR approved is attributable in part to the difference between 2004 actual and the average of 2004 and 2003, and the actual additions in

2005 and 2006. In this section the variances are broken down to isolate the impact of the 2006 actual capital expenditure.

Preamble:

Variances in gross asset accounts for the 2006 Actual vs. 2006 EDR Approved are primarily attributable to the following programs / projects.

Wood Pole Replacement Program: Predecessor utilities did not have a defective wood pole replacement program. Many poles are in excess of 40 years old. There is a risk of the poles falling from high winds and ice loading, posing a significant hazard to the public. The work is in various communities and does not represent significant pole line rebuilt, but replacement of individual poles.

Explanation: Every year Westario Power replaces defective wood poles (described above). Further, the bulk of Westario Power's distribution is overhead, and plant rebuild for feeder reinforcement is another annual program. Work was distributed over 1830, 1835, 1850, and 1855.

Porcelain Insulator Replacement Program: Porcelain insulators are not a problem unique to Westario Power Inc. These have widespread use in the province. Because of age and original manufacturing techniques these insulators break off at the base and drop energized conductors onto adjacent feeders and grounded equipment.

Explanation: Westario Power replaces porcelain insulators annually. Broken insulators drop energized conductors onto ground equipment causing widespread system outages. Work was mostly in 1835.

5kV Cable Replacement Program: In the past 5kV butyl rubber cable and "Pole Trans" transformers were used to service residential neighborhoods. The 5 kV cable is direct buried and is failing as it has surpassed its 30 year lifespan. The Pole Tran transformers are heavily loaded and extremely congested, posing worker safety issues.

1 Explanation: Emergency directional boring is expensive and, depending on the season, may
2 not be practical. Temporary poles have been built to restore power. New conduit is bored into
3 placed and new cables are pulled through the conduits. The Pole Tran transformers are
4 replaced with new pad mount transformers, with sufficient capacity and accessibility.

5
6 **Pole Line Rebuild Projects:** These projects are identified for inclusion as they serve the
7 purpose of increasing reliability, increasing feeder capacity or the condition of the line and the
8 severe impact of its failure on customer interruption make the work necessary.

9
10 Explanation: Usually, pole line work is a particular project serving a particular need. In 2006,
11 five pole-line projects were undertaken, two to increase feeder capability between substations
12 and the other three to rebuild decaying pole lines carrying the 44kV feeder to substations. Work
13 was be distributed over 1830, 1835, 1850, and 1855.

14
15 **Underground Conversion Projects:** These projects are for burying plant where it is deemed
16 the solution for distribution plant management.

17
18 Explanation: Usually these are in very congested areas where buildings are close to the
19 roadway providing little clearance between overhead wires and the buildings, or in heavily treed
20 areas where tree management is problematic and burying the cables offers the best solution for
21 both the customers and the utility.

22
23 **Transformer Replacements:** This project is to replace substandard transformer installations in
24 Harriston.

25
26 Explanation: Replace three-phase transformer banks. The installations pose back-feed hazards
27 to the Line Staff. The work in 2005 was the final phase of a planned replacement program and
28 resulted in standardization of all three-phase transformers in Harriston.

29 **Wholesale Metering:** Install IESO complaint metering when existing metering installations
30 expire.

31

Explanation: Most Westario-predecessor utilities utilized Hydro One for MSP services. Most of the wholesale meters were installed inside the HONI 44kV Transformer Stations. Under conveyance rules, Westario Power installed new or acquired the old HONI Primary Metering Equipment at the HONI delivery points. This project is an IESO regulatory requirement.

Expenditures by Asset Account

Account Description	2006 Actual	2006 EDR Approved	Variance in \$	% change
1805-Land	242,769	107,769	135,000	125.3%

Purchase of land in 2006 for new building that was built in 2007

Account Description	2006 Actual	2006 EDR Approved	Variance in \$	% change
1830-Poles, Towers and Fixtures	4,811,058	3,892,678	918,380	23.6%

2005 Additions and difference between 2004 actual and average of 2004 and 2003 actuals for the 2006 EDR approved balance	694,643
2006 Actual	223,737
	918,380

2005 capital work in multiple projects groups:

- Pole replacements in conjunction with the 5kV cable replacement program.
- Pole replacements in conjunction with wood pole replacement program.
- Pole replacements in conjunction in works driven by customer requests or municipal requests to relocate.
- Pole replacements in conjunction with pole-line rebuilds.
- Pole replacements in conjunction with wholesale metering.

2006 capital work in multiple projects groups:

- Pole replacements in conjunction with wood pole replacement program.
- Pole replacements in conjunction with pole-line rebuild projects.

Account Description	2006 Actual	2006 EDR Approved	Variance in \$	% change
1835-Overhead Conductors and Devices	6,734,937	5,137,278	1,597,659	31.1%

1

2005 Additions and difference between 2004 actual and average of 2004 and 2003 actuals for the 2006 EDR approved balance	1,333,291
2006 additions	628,765
Reallocation to 1845 – Underground Conductors and Devices	(364,397)
	1,597,659

2

3 2005 capital work in Overhead conductors and devices in conjunction with:

- 4 • The 5kV cable replacement programs.
- 5 • Wood pole replacements.
- 6 • Works driven by customer requests or municipal requests to relocate.
- 7 • Porcelain insulator replacement program.
- 8 • Pole-line rebuilds.
- 9 • Underground conversions.
- 10 • Wholesale metering.

11

12 2006 capital work in Overhead conductors and devices in conjunction with:

- 13 • Wood pole replacements projects.
- 14 • Pole-line rebuild projects.
- 15 • Porcelain insulator replacement program.

16

Account Description	2006 Actual	2006 EDR Approved	Variance in \$	% change
1840-Underground Conduit	2,094,546	1,315,937	778,609	59.2%

17

2005 Additions and difference between 2004 actual and average of 2004 and 2003 actuals for the 2006 EDR approved balance	418,998
2006 additions	<u>360,612</u>
	778,610

18

19 2005 capital work in underground conduit in conjunction with:

- Subdivisions.
 - The 5kV cable replacement program.
- 2006 capital work in underground conduit in conjunction with:
- Subdivisions.
 - The 5kV cable replacement program.

Account Description	2006 Actual	2006 EDR Approved	Variance in \$	% change
1845-Underground Conductors and Devices	5,563,155	3,444,539	2,118,616	61.5%

	2005 Additions and difference between 2004 actual and average of 2004 and 2003 actuals for the 2006 EDR approved balance	676,598
	2006 additions	1,077,621
	Reallocation from 1835 – Overhead Conductors and Devices	364,397
		2,118,616

2005 capital work in underground conductor and devices in conjunction with:

- The 5kV cable replacement projects.
- Underground work as a result of wood pole replacements.
- Work driven by customer requests or municipal requests to relocate.
- Underground work as a result of pole line rebuilds.
- Underground conversion projects.

2006 capital work in underground conductor and devices in conjunction with:

- Wood pole replacement projects, pole-line rebuild projects, and insulator replacement projects.
- PCB Transformer Retirement Program.
- The 5kV cable replacement program.
- Miscellaneous services and subdivisions.

Account Description	2006 Actual	2006 EDR Approved	Variance in \$	% change
1850-Line Transformers	5,896,988	3,824,513	2,072,475	54.2%

	2005 Additions and difference between 2004 actual and average of 2004 and 2003 actuals for the 2006 EDR approved balance	710,088
	2006 additions	<u>1,362,387</u>
		2,072,475

2005 capital work in line transformers in conjunction with:

- The 5kV cable replacement projects.
- Wood pole replacement projects.
- Work driven by customer requests or municipal requests to relocate.
- PCB transformer retirement projects.
- Pole line rebuilds.
- Planned transformer replacement projects.
- Underground conversion projects.
- Subdivisions, misc services, and customer-driven works.

2006 capital work in line transformers in conjunction with:

- Transformer replacements as a result of the wood pole replacement program.
- Transformer replacement in conjunction with pole-line rebuild projects.
- Replacement transformers in the 5 kV cable replacement areas.
- Subdivisions, miscellaneous services and customer-driven work.

Account Description	2006 Actual	2006 EDR Approved	Variance in \$	% change
1855-Services	2,727,052	2,069,198	657,854	31.8%

	2005 Additions and difference between 2004 actual and average of 2004 and 2003 actuals for the 2006 EDR approved balance	430,041
	2006 additions	<u>227,813</u>
		657,854

Both 2006 and 2005 capital work in services in conjunction with:

- The 5kV cable replacement.
- The wood pole replacement projects.
- Work driven by customer requests or municipal requests to relocate.
- Pole line rebuild projects.
- Underground conversion work.
- Subdivisions and customer driven requests

Account Description	2006 Actual	2006 EDR Approved	Variance in \$	% change
1860-Meters	2,302,027	1,866,214	435,813	23.4%

2005 Additions and difference between 2004 actual and average of 2004 and 2003 actuals for the 2006 EDR approved balance	370,087
2006 additions	65,726
	435,813

2005 capital work in meters in conjunction with:

- Revenue meter spend, includes purchasing new meters, instrument transformers, metering devices and labour to install
- Wholesale metering spend; for IESO compliance, as follows:
 - o Teeswater Primary Metering Equipment ('PME')
 - o Kincardine PME
 - o Mildmay PME
 - o Harriston PME
 - o Clifford PME
 - o Wingham PME
 - o Southampton MS1 PME
 - o Southampton MS2 PME
 - o Southampton MS3 PME

2006 capital work in meters in conjunction with:

- Revenue meter spend, includes procuring new meters, instrument transformers, metering devices and labour to install.
- Wholesale metering spend; for IESO compliance, as follows:
 - o Upgrade wholesale metering customer
 - o Neustadt PME

Account Description	2006 Actual	2006 EDR Approved	Variance in \$	% change
1925-Computer Software	267,519	255,224	12,295	4.8%

2005 Additions and difference between 2004 actual and average of 2004 and 2003 actuals for the 2006 EDR approved balance	12,295
2006 additions	<u>0</u>
	12,295

1 **Accumulated Depreciation Table**

2

3 The following attachment is the Accumulated Depreciation Table.

4

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B2 Amortization of Capital Assets

Capital Asset Account	2006 EDR Approved	Variance to 2006 Actual		
		Amortization Expense	Retirements / Other	Ending Balance
1610-Miscellaneous Intangible Plant				
1805-Land				
1806-Land Rights				
1808-Buildings and Fixtures	(1,210)	(653)	(160)	-2023
1810-Leasehold Improvements				
1815-Transformer Station Equipment - Normally Primary above 50 kV				
1820-Distribution Station Equipment - Normally Primary below 50 kV	(507,072)	(284,630)	(70,464)	-862166
1830-Poles, Towers and Fixtures	(601,476)	(402,126)	(91,247)	-1094849
1835-Overhead Conductors and Devices	(786,408)	(551,196)	(104,824)	-1442428
1840-Underground Conduit	(199,475)	(159,181)	(34,477)	-393133
1845-Underground Conductors and Devices	(608,691)	(426,972)	(94,648)	-1130311
1850-Line Transformers	(598,029)	(435,961)	(109,259)	-1143249
1855-Services	(286,022)	(220,310)	(49,602)	-555934
1860-Meters	(255,575)	(193,515)	(41,497)	-490587
1905-Land				
1906-Land Rights				
1908-Buildings and Fixtures				
1910-Leasehold Improvements				
1915-Office Furniture and Equipment				
1920-Computer Equipment - Hardware				
1925-Computer Software	(75,340)	(107,006)	(26,752)	-209098
1930-Transportation Equipment				
1935-Stores Equipment				
1940-Tools, Shop and Garage Equipment				
1945-Measurement and Testing Equipment				
1950-Power Operated Equipment				
1955-Communication Equipment				
1960-Miscellaneous Equipment				

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B2 Amortization of Capital Assets

Capital Asset Account	2006 EDR Approved	Variance to 2006 Actual		
		Amortization Expense	Retirements / Other	Ending Balance
1965-Water Heater Rental Units				
1970-Load Management Controls - Customer Premises				
1975-Load Management Controls - Utility Premises	(189,662)	(43,105)	(25,864)	-258631
1980-System Supervisory Equipment				
1985-Sentinel Lighting Rental Units				
1990-Other Tangible Property				
1995-Contributions and Grants - Credit	139,234	245,012	39,913	424159
2005-Property Under Capital Leases				
TOTAL	(3,969,726)	(2,579,643)	-608,881	-7,158,250
Accumulated Amortization on Balance Sheet	(3,969,726)	1.1600-Accumulated Amortization		(7,158,250)
Amortization Expense Adjustment				
Amortization Expense				

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B2 Amortization of Capital Assets

Capital Asset Account	2006 Actual Ending Balance	2007 Actual		
		Amortization Expense	Retirements / Other	Ending Balance
1610-Miscellaneous Intangible Plant				
1805-Land				
1806-Land Rights				
1808-Buildings and Fixtures	(2,023)	(24,758)		(26,781)
1810-Leasehold Improvements				
1815-Transformer Station Equipment - Normally Primary above 50 kV				
1820-Distribution Station Equipment - Normally Primary below 50 kV	(862,166)	(143,364)		(1,005,530)
1830-Poles, Towers and Fixtures	(1,094,849)	(217,108)		(1,311,957)
1835-Overhead Conductors and Devices	(1,442,428)	(316,175)		(1,758,603)
1840-Underground Conduit	(393,133)	(100,545)		(493,678)
1845-Underground Conductors and Devices	(1,130,311)	(265,053)		(1,395,364)
1850-Line Transformers	(1,143,249)	(276,309)		(1,419,558)
1855-Services	(555,934)	(125,438)		(681,372)
1860-Meters	(490,587)	(105,800)		(596,387)
1905-Land				
1906-Land Rights				
1908-Buildings and Fixtures				
1910-Leasehold Improvements				
1915-Office Furniture and Equipment				
1920-Computer Equipment - Hardware				
1925-Computer Software	(209,098)	(53,503)		(262,601)
1930-Transportation Equipment				
1935-Stores Equipment				
1940-Tools, Shop and Garage Equipment				
1945-Measurement and Testing Equipment				
1950-Power Operated Equipment				
1955-Communication Equipment				
1960-Miscellaneous Equipment				

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B2 Amortization of Capital Assets

Capital Asset Account	2006 Actual Ending Balance	2007 Actual		
		Amortization Expense	Retirements / Other	Ending Balance
1965-Water Heater Rental Units				
1970-Load Management Controls - Customer Premises				
1975-Load Management Controls - Utility Premises	-258631			(258,631)
1980-System Supervisory Equipment				
1985-Sentinel Lighting Rental Units				
1990-Other Tangible Property				
1995-Contributions and Grants - Credit	424159	194,413		618,572
2005-Property Under Capital Leases				
TOTAL	-7,158,250	-1,433,640		-8,591,890
Accumulated Amortization on Balance Sheet	1.1600-Accumulated Amortization			
Amortization Expense Adjustment				
Amortization Expense		1,433,640		

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B2 Amortization of Capital Assets

Capital Asset Account	2007 Actual Ending Balance	2008 Projection		
		Amortization Expense	Retirements / Other	Ending Balance
1610-Miscellaneous Intangible Plant				
1805-Land				
1806-Land Rights				
1808-Buildings and Fixtures	(26,781)	(49,196)		(75,977)
1810-Leasehold Improvements				
1815-Transformer Station Equipment - Normally Primary above 50 kV				
1820-Distribution Station Equipment - Normally Primary below 50 kV	(1,005,530)	(150,908)		(1,156,438)
1830-Poles, Towers and Fixtures	(1,311,957)	(225,507)		(1,537,464)
1835-Overhead Conductors and Devices	(1,758,603)	(340,166)		(2,098,769)
1840-Underground Conduit	(493,678)	(114,859)		(608,537)
1845-Underground Conductors and Devices	(1,395,364)	(286,479)		(1,681,843)
1850-Line Transformers	(1,419,558)	(292,833)		(1,712,391)
1855-Services	(681,372)	(135,011)		(816,383)
1860-Meters	(596,387)	(114,116)		(710,503)
1905-Land				
1906-Land Rights				
1908-Buildings and Fixtures				
1910-Leasehold Improvements				
1915-Office Furniture and Equipment		(18,172)	(115,088)	(133,260)
1920-Computer Equipment - Hardware		(20,174)	(309,478)	(329,652)
1925-Computer Software	(262,601)	(26,999)	(377,214)	(666,814)
1930-Transportation Equipment		(127,177)	(775,843)	(903,020)
1935-Stores Equipment		(1,776)	(5,038)	(6,814)
1940-Tools, Shop and Garage Equipment		(10,793)	(126,776)	(137,569)
1945-Measurement and Testing Equipment		(5,146)	(10,771)	(15,917)
1950-Power Operated Equipment		(971)	(23,214)	(24,185)
1955-Communication Equipment		(12,599)	(73,733)	(86,332)
1960-Miscellaneous Equipment		(2,796)	(15,396)	(18,192)

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B2 Amortization of Capital Assets

Capital Asset Account	2007 Actual Ending Balance	2008 Projection		
		Amortization Expense	Retirements / Other	Ending Balance
1965-Water Heater Rental Units				
1970-Load Management Controls - Customer Premises				
1975-Load Management Controls - Utility Premises	(258,631)			(258,631)
1980-System Supervisory Equipment				
1985-Sentinel Lighting Rental Units				
1990-Other Tangible Property				
1995-Contributions and Grants - Credit	618,572	215,222		833,794
2005-Property Under Capital Leases				
TOTAL	-8,591,890	-1,720,456	-1,832,552	-12,144,898
Accumulated Amortization on Balance Sheet	(8,591,890)	1.1600-Accumulated Amortization		
Amortization Expense Adjustment				
Amortization Expense		1,720,456		

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B2 Amortization of Capital Assets

Capital Asset Account	2008 Projection Ending Balance	2009 Projection		
		Amortization Expense	Retirements / Other	Ending Balance
1610-Miscellaneous Intangible Plant				
1805-Land				
1806-Land Rights				
1808-Buildings and Fixtures	(75,977)	(49,516)		(125,493)
1810-Leasehold Improvements				
1815-Transformer Station Equipment - Normally Primary above 50 kV				
1820-Distribution Station Equipment - Normally Primary below 50 kV	(1,156,438)	(162,392)		(1,318,830)
1830-Poles, Towers and Fixtures	(1,537,464)	(242,357)		(1,779,821)
1835-Overhead Conductors and Devices	(2,098,769)	(368,517)		(2,467,286)
1840-Underground Conduit	(608,537)	(121,345)		(729,882)
1845-Underground Conductors and Devices	(1,681,843)	(304,090)		(1,985,933)
1850-Line Transformers	(1,712,391)	(307,538)		(2,019,929)
1855-Services	(816,383)	(139,707)		(956,090)
1860-Meters	(710,503)	(120,272)		(830,775)
1905-Land				
1906-Land Rights				
1908-Buildings and Fixtures				
1910-Leasehold Improvements				
1915-Office Furniture and Equipment	(133,260)	(19,190)		(152,450)
1920-Computer Equipment - Hardware	(329,652)	(23,959)		(353,611)
1925-Computer Software	(666,814)	(25,157)		(691,971)
1930-Transportation Equipment	(903,020)	(138,502)	10,000	(1,031,522)
1935-Stores Equipment	(6,814)	(5,401)		(12,215)
1940-Tools, Shop and Garage Equipment	(137,569)	(15,293)		(152,862)
1945-Measurement and Testing Equipment	(15,917)	(5,146)		(21,063)
1950-Power Operated Equipment	(24,185)	(3,071)		(27,256)
1955-Communication Equipment	(86,332)	(10,286)		(96,618)
1960-Miscellaneous Equipment	(18,192)	(2,796)		(20,988)

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B2 Amortization of Capital Assets

Capital Asset Account	2008 Projection Ending Balance	2009 Projection		
		Amortization Expense	Retirements / Other	Ending Balance
1965-Water Heater Rental Units				
1970-Load Management Controls - Customer Premises				
1975-Load Management Controls - Utility Premises	(258,631)			(258,631)
1980-System Supervisory Equipment				
1985-Sentinel Lighting Rental Units				
1990-Other Tangible Property				
1995-Contributions and Grants - Credit	833,794	234,822		1,068,616
2005-Property Under Capital Leases				
TOTAL	-12,144,898	-1,829,713	10,000	-13,964,611
Accumulated Amortization on Balance Sheet				
Amortization Expense Adjustment				
Amortization Expense		1,829,713		

Materiality Analysis on Accumulated Depreciation

	2009 Proj. to 2008 Proj.	2008 Proj. to 2007 Actual	2007 Actual to 2006 Actual	2006 Actual to 2006 EDR
Total Accumulated Depreciation	\$13,964,610	\$12,144,897	\$8,591,890	\$7,158,250
Percent	1%	1%	1%	1%
Threshold	\$139,646	\$121,448	\$85,918	\$71,582

2009 Test vs. 2008 Bridge

	2009 Test	2008 Bridge	Variance	
1808 – Buildings and Fixtures	(125,493)	(75,977)	(49,516)	65.17%
1820 – Distribution Station Equipment normally primary <50kV	(1,318,830)	(1,156,438)	(162,392)	14.04%
1830 – Poles	(1,779,821)	(1,537,464)	(242,357)	15.76%
1835 – Overhead Conductors and Devices	(2,467,286)	(2,098,769)	(368,517)	17.56%
1840 – Underground Conduit	(729,882)	(608,537)	(121,345)	19.94%
1845 – Underground Conductors and Devices	(1,985,933)	(1,681,843)	(304,090)	18.08%
1850 – Line Transformers	(2,019,929)	(1,712,391)	(307,538)	17.96%
1855 – Services	(956,090)	(816,383)	(139,707)	17.11%
1860 – Meters	(830,775)	(710,503)	(120,272)	16.93%
1915 – Office Furniture and Equipment	(152,450)	(133,260)	(19,190)	14.40%
1920 – Computer Equipment – Hardware	(353,611)	(329,652)	(23,959)	7.27%
1925 – Computer Software	(691,971)	(666,824)	(25,157)	3.77%
1930 – Transportation Equipment	(1,031,522)	(903,020)	(128,502)	14.23%
1935 – Stores Equipment	(12,215)	(6,814)	(5,401)	79.26%
1940 – Tools, Shop and Garage Equipment	(152,862)	(137,569)	(15,293)	11.12%
1945 – Measurement and Testing Equipment	(21,063)	(15,917)	(5,146)	32.33%
1950 – Power Operated Equipment	(27,256)	(24,185)	(3,071)	12.70%
1955 – Communication Equipment	(96,618)	(86,332)	(10,286)	11.91%
1960 – Miscellaneous Equipment	(20,988)	(18,192)	(2,796)	15.37%
1975 – Load Management Controls – Utility Premises	(258,631)	(258,631)	0	

The variances from 2009 Test to 2008 Projected are consistent with the increases in the capital plan and normal depreciation expense incurred for the year. There has been no change in the depreciation rates between 2009 and 2008.

2008 Bridge vs. 2007 Actual

	2008 Projected	2007 Actual	Variance	
1808 – Buildings and Fixtures	(75,977)	(26,781)	(49,196)	183.70%
1820 – Distribution Station Equipment normally primary <50kV	(1,156,438)	(1,005,530)	(150,908)	15.01%
1830 – Poles	(1,537,464)	(1,311,957)	(225,507)	17.19%
1835 – Overhead Conductors and Devices	(2,098,769)	(1,758,603)	(340,166)	19.34%
1840 – Underground Conduit	(608,537)	(493,678)	(114,859)	23.27%
1845 – Underground Conductors and Devices	(1,681,843)	(1,395,364)	(286,479)	20.53%
1850 – Line Transformers	(1,712,391)	(1,419,558)	(292,833)	20.63%
1855 – Services	(816,383)	(681,372)	(135,011)	19.81%
1860 – Meters	(710,503)	(596,387)	(114,116)	19.13%
1915 – Office Furniture and Equipment	(133,260)	0	(133,260)	100.00%
1920 – Computer Equipment – Hardware	(329,652)	0	(329,652)	100.00%
1925 – Computer Software	(666,824)	(262,601)	(404,213)	153.93%
1930 – Transportation Equipment	(903,020)	0	(903,020)	100.00%
1935 – Stores Equipment	(6,814)	0	(6,814)	100.00%
1940 – Tools, Shop and Garage Equipment	(137,569)	0	(137,569)	100.00%
1945 – Measurement and Testing Equipment	(15,917)	0	(15,917)	100.00%
1950 – Power Operated Equipment	(24,185)	0	(24,185)	100.00%
1955 – Communication Equipment	(86,332)	0	(86,332)	100.00%
1960 – Miscellaneous Equipment	(18,192)	0	(18,192)	100.00%
1975 – Load Management Controls – Utility Premises	(258,631)	(258,631)	0	

On July 13, 2007 the Ontario Energy Board issued a decision and order (File #EB02007-0103) for Westario Power Inc. to amalgamate with Westario Power Holdings Inc. and Westario Power Services Inc. The amalgamation between Westario Power Inc., Westario Power Holdings Inc. and Westario Power Services Inc. became effective January 1, 2008. As a result of the amalgamation; assets in accounts 1915 to 1960 were transferred from Westario Power Services Inc. to Westario Power Inc. at net book value (gross cost less accumulated depreciation). All assets in the above class are used in the day to day operations of Westario Power Inc. Variances in accounts 1915 to 1960 are as a result of the amalgamation and are consistent with the increases in the capital plan and normal depreciation expense incurred for the year.

The variances from 2008 Bridge to 2007 Actual are consistent with the increases in the capital plan and normal depreciation expense incurred for the year. There has been no change in the depreciation rates between 2008 and 2007.

2007 Actual vs. 2006 Actual

	2007 Actual	2006 Actual	Variance	
1808 – Buildings and Fixtures	(26,781)	(2,023)	(24,758)	1223.83%
1820 – Distribution Station Equipment normally primary <50kV	(1,005,530)	(862,166)	(143,364)	16.63%
1830 – Poles	(1,311,957)	(1,094,849)	(217,108)	19.83%
1835 – Overhead Conductors and Devices	(1,758,603)	(1,442,428)	(316,175)	21.92%
1840 – Underground Conduit	(493,678)	(393,133)	(100,545)	25.58%
1845 – Underground Conductors and Devices	(1,395,364)	(1,130,310)	(265,054)	23.45%
1850 – Line Transformers	(1,419,558)	(1,143,249)	(276,309)	24.17%
1855 – Services	(681,372)	(555,934)	(125,438)	22.56%
1860 – Meters	(596,387)	(490,587)	(105,800)	21.57%
1925 – Computer Software	(262,601)	(209,098)	(53,503)	25.59%
1975 – Load Management Controls – Utility Premises	(258,631)	(258,631)	0	

The variances from 2007 Actual to 2006 Actual are consistent with the increases in the capital plan and normal depreciation expense incurred for the year. There has been no change in the depreciation rates between 2007 and 2006.

2006 Actual vs. 2006 EDR Approved

	2006 Actual	2006 EDR Approved	Variance	
1808 – Buildings and Fixtures	(2,023)	(1,210)	(813)	67.19%
1820 – Distribution Station Equipment normally primary <50kV	(507,072)	(355,094)	(355,094)	70.03%
1830 – Poles	(1,094,849)	(601,476)	(493,373)	82.03%
1835 – Overhead Conductors and Devices	(1,442,428)	(786,408)	(656,020)	83.42%
1840 – Underground Conduit	(393,133)	(199,475)	(193,658)	97.08%
1845 – Underground Conductors and Devices	(1,130,310)	(608,691)	(521,619)	85.70%
1850 – Line Transformers	(1,143,249)	(598,029)	(545,220)	91.17%
1855 – Services	(555,934)	(286,022)	(269,912)	94.37%
1860 – Meters	(490,587)	(255,575)	(235,012)	91.95%
1925 – Computer Software	(209,098)	(75,340)	(133,758)	177.54%
1975 – Load Management Controls – Utility Premises	(258,631)	(189,662)	(68,969)	36.36%

The variances from 2006 Actual vs. 2006 EDR Approved are a combination of the difference between 2004 actual and the average of 2003 and 2004 balances for the purposes of the 2006 EDR Approved amount, 2005 actual and 2006 actual. Of the total variance, approximately \$842,402 can be attributed to the difference between 2004 Actual and the 2006 EDR Approved, with the balance; approximately \$2,631,046 attributed to 2005 and 2006. The variance for 2005 and 2006 are consistent with the increases in the capital plan and normal depreciation expense incurred for the year. There has been no change in the depreciation rates between 2006 EDR Approved and 2006 Actual.

Capital Plan by Project

Overview:

The Applicant has been, and continues to be, focused on maintaining the adequacy, reliability and quality of service to its distribution customers. The capital expenditures planned for 2009 reflect this ongoing focus. The Applicant's overall capital budget for 2009 is \$3,064,400, reflecting an increase of \$139,140 (4.75 percent) over 2008.

The Applicant's Asset Management Policies and Procedures is attached to this schedule.

This Overview contains:

- (a) Budget plan process
- (b) Descriptions of certain key elements of the Applicant's 2009 capital budget, in the following categories and Types:
 - 1. Distribution Plant
 - 1.1. Customer Demand
 - 1.1.1. Commercial/industrial services
 - 1.1.2. Low voltage services
 - 1.1.3. Subdivision development
 - 1.2. Public and Worker Safety
 - 1.2.1. Pole line replacement
 - 1.2.2. Copper wire replacement
 - 1.3. System Reliability
 - 1.3.1. Defective pole replacements
 - 1.3.2. Recloser replacements
 - 1.3.3. Contingency supply
 - 2. Revenue Metering
 - 3. General Plant
 - 3.1 Computer hardware and software
 - 3.2 Transportation and related equipment

- 3.3 Tools and equipment
- 3.4 Stores equipment
- 3.5 Power operated equipment
- 3.6 Building and fixtures
- 3.7 Office furniture and equipment

(a) Budget Plan Process

Each department Manager is responsible for the preparation of their departmental capital budget.

The following directives are provided to each Manager:

- All department budgets are to be built using a “bottom up” approach, which requires each functional area within Westario Power to build work plans that identify resources, including labour, materials and other third party costs that are required to execute the work plans. This approach ensures that budgets are developed based on the actual work to be completed during the fiscal year, as opposed to a historical costing approach.
- Budgets are to be supported by documented assumptions.

Once all distribution plant related projects have been identified, they are evaluated against certain criteria as described in the Asset Management Policy found in Exhibit 2, Tab 3, Schedule 1 in order to affect a relative ranking of projects. Decisions on priorities are made to include those projects determined to be the most important within a level of affordability. This plan is evaluated by the Line Superintendent responsible for Design & Construction and Network Planning and then reviewed and supported by the Manager of System Reliability.

For non-distribution plant assets, each manager is responsible for identifying the needs of their department and providing budgets that are supported by documented assumptions.

A final budget package is produced to present to the Management Team for their review and approval. Once approved by the CEO, the capital budget is presented to the WPI Board of Directors for approval.

The 2008 Business Plan identified the need to improve the productivity of field supervisors and staff through the leveraging or extension of existing and/or new technologies. The plan provides for the deployment of laptop computers with remote connectivity to key field staff. This technology will provide remote access to up-to-date record maps, permit better communication of work instructions, and reduce the time needed to complete paperwork.

The Business Plan also set an objective of developing an asset replacement model for additions and betterments to the distribution system. Having more complete and accurate details on the components of the system would permit better planning for, and management of, the assets.

1. Distribution Plant

In November 2000, Westario Power Inc. formed from the merger of eight municipal distribution companies serving fifteen communities. In the commentary below, specific projects may be identified by community. Further explanation of the projects, justification, and goals are described in Exhibit 2, Tab 3, Schedule 6.

Port Elgin

Port Elgin has one of the highest rates of residential and commercial growth within Westario Power's service territory.

The Port Elgin distribution system is approximately 60 percent underground. The overhead portion is in reasonable condition, however, much of the overhead system is comprised of aerial spaced conductor that will require reconstructing to achieve minimum clearances between the high voltage conductors as required under the Electrical Safety Code.

There is a significant amount of 5 kV underground distribution comprised of butyl rubber cable. This type of cable has shown to have a life expectancy of about 20 years. Most of this cable is well over 30 years old. When it fails, the major problem is that it is direct buried. The cost for emergency boring is extremely high when dealing with a lateral feed. In a number of cases, it has been necessary to set poles temporarily and string lines to re-supply customers. A 10-year

1 program to replace all butyl rubber cables was initiated in 2006. This program will be placed on
2 hold in 2009 to allow Westario Power to address the more heavily weighted projects involving
3 No. 6 copper wire and pole-line replacements.

4
5 Four projects to replace No. 6 copper conductors have been identified and these replacements
6 will be undertaken in future budget years.

7 Five pole-line replacement projects have been identified for Port Elgin. One pole-line
8 replacement will be undertaken in 2009.

9
10 **Southampton**

11 Like Port Elgin, Southampton also has one of the highest rates of residential growth within
12 Westario Power's service territory.

13
14 Southampton is primarily an overhead system (approximately 75 percent). Thirty-five areas that
15 have No. 6 copper conductors have been identified. Three projects will be undertaken in 2009.
16 The balance of these projects will be undertaken in future budget years.

17
18 Six pole line replacement projects have been identified in Southampton; one of which will be
19 undertaken in 2008, and the balance will be undertaken in future budget years.

20
21 **Kincardine**

22 The Kincardine system is 75 percent overhead and in fair to good condition. Kincardine has a
23 high rate of residential growth.

24
25 In 2008 the final phase of the 5 kV underground cable replacement program will be undertaken
26 in Kincardine. The 2008 work will eliminate the remainder of all PoleTrans transformers and the
27 removal of the balance of the 5 kV cable. No further budgeting will be required in Kincardine to
28 replace the old 5kV cable.

29
30 In 2008 a small underground cable and foundation replacement program is required on a
31 residential street for public safety, as the old fibreglass foundations are collapsing.

1
2 Kincardine has a large amount of No. 6 copper primary conductors that will require replacement.
3 One project was undertaken in 2008, and two will be undertaken in 2009; leaving thirteen No. 6
4 copper projects to be undertaken in future budget years.

5
6 Five pole-line replacement projects have been identified for Kincardine; one of which will be
7 undertaken in 2009; and the balance in future budget years.

8
9 **Ripley**

10 Ripley has an overhead system with minimal underground plant. Traditional levels of
11 maintenance and capital works should be sufficient to maintain the system.

12
13 The focus for 2008 will be targeting some of the worst poles for replacement under our Capital
14 pole replacement program. Two projects to replace No. 6 copper conductors have been
15 identified, and will be undertaken in future budget years.

16
17 One pole-line replacement projects has been identified for Ripley which will be undertaken in a
18 future budget year.

19
20 **Lucknow**

21 Lucknow is an overhead system. Lucknow has a relatively new substation and some new
22 primary feeders. Nine projects to replace No. 6 copper conductors have been identified. One
23 will be undertaken in 2009, with the balance being undertaken in future budget years.

24
25 Three pole-line replacement projects have been identified for Lucknow which will be undertaken
26 in future budget years.

27
28 **Wingham**

29 The distribution system in Wingham is mostly overhead. Poles and lines are in poor condition
30 and require attention. Data collection and mapping will contribute for developing a longer-range
31 work plan for this system.

1
2 In 2009, the Wingham MS1 substation will be refitted with new reclosers to effectively allow
3 feeders to be switched out under storm conditions and to protect the substation transformer.

4 Seven projects to replace No. 6 copper conductors have been identified, and one will be
5 undertaken in 2009; the balance will be undertaken in future budget years.

6 Two pole-line replacement projects have been identified for Wingham; all of which will be
7 undertaken in future budget years.

8
9 **Teeswater**

10 The Teeswater distribution system is overhead. Teeswater has a relatively new substation.

11 Three projects to replace No. 6 copper conductors have been identified, and these will be
12 undertaken in future budget years.

13
14 Four pole-line replacement projects have been identified for Teeswater; one of which will be
15 undertaken in 2009; and the balance in future budget years.

16
17 **Mildmay**

18 Mildmay has an overhead system with some pockets of underground residential distribution.
19 Traditional levels of maintenance and capital works should be sufficient to maintain the system.

20
21 **Walkerton**

22 The Walkerton overhead system is in good condition. New underground residential distribution
23 has been added in recent years, however load growth is low.

24 In 2008 the Walkerton MS1 substation will be replaced as the existing substation under-oil
25 insulation is failing.

26
27 Five projects to replace No. 6 copper conductors have been identified, one of which will be
28 undertaken in 2009.

29
30 One pole-line replacement project has been identified; which will be undertaken in future budget
31 years.

Palmerston

Palmerston is an overhead system, but is seeing some growth in the form of a new residential underground subdivision.

In 2008, the Palmerston substation will be refitted with new reclosers to effectively allow feeders to be switched out under storm conditions and to protect the substation transformer. The substation yard will also require a new ground grid. The present ground gradient does not meet the minimum requirements of the Electrical Safety Code.

In 2008 one project to replace 27 secondary trench boxes for public safety will be undertaken.

One project to replace No. 6 copper conductors has been identified, and will be undertaken in future budget years.

Harriston

Harriston is an overhead system, with small pockets of underground distribution.

In 2008 porcelain insulators will be replaced. Also in 2008 a spare substation transformer will be acquired for installation at Harriston MS. The installation at the site will not occur until 2009.

Three pole-line replacement projects have been identified for Harriston; one of which will be undertaken in 2009; and the balance in future budget years.

Clifford

Clifford is a small overhead system; with minimal underground plant. Normal practices are adequate to maintain system reliability.

Elmwood

This is a small overhead system; with minimal underground plant. Normal practices are adequate to maintain system reliability.

Hanover

The system is 75 percent overhead with the balance underground. Overall condition of the system is fair to good.

Fourteen projects to replace No. 6 copper conductors have been identified, and one will be undertaken in 2009. No. 6 copper primary conductors need to be replaced due to age and brittleness of the conductors.

Seven pole-line replacement projects have been identified for Hanover. One pole-line replacement will be undertaken in 2009.

Neustadt

Neustadt is small overhead system. Two projects to replace No. 6 copper conductors have been identified, and will be undertaken in future budget years.

Projects of the Distribution Plant

The following discussion addresses various key projects within the distribution plant component of the Applicant's 2009 Capital Budget. Overall, the Applicant intends to spend a total of \$2,779,700 on distribution plant in 2009, on the following categories of projects:

Table 1 – Summary of Distribution Plant Capital 2006-2009 Total by Type

Category/Year	2006 actual	2007 actual	2008 budget	2009 budget
	(\$000)	(\$000)	(\$000)	(\$000)
Public Safety	124.8	115.4	317.7	1,607.5
System Reliability	1,766.9	1,768.9	1,599.4	400.4
Regulatory	311.9	79.2	27.0	0
Customer Demand	1,743.0	1,060.6	690.1	771.8
Total	3,946.6	3,024.1	2,634.2	2,779.7

Projects within the categories in the above table are discussed on the following pages.

1.1. 2009 Customer Demand Projects

Total Cost - \$771,800

Description

Projects in this group include installations of service wires and transformers to connect new customers to the electrical distribution system, new subdivision development, and roadway relocations.

The work planned for 2009 includes new residential services in existing subdivisions, residential "in-fill" services outside of subdivisions, low voltage services, commercial/industrial customers which are typically padmount services, and new subdivisions.

Westario Power is not aware of any requirements for plant relocation to accommodate other utility work or municipal or provincial roadwork in 2009.

Justification

Westario Power is obligated under the Code to connect new customer services. The replacement component is justified on the basis of the obligation to meet changing customer needs.

Relocation projects, should a request be made, are performed primarily because third parties need plant relocated in order to do their work. Projects in this group benefit customers by increasing reliability as permanent relocations that are built to current standards replace plant that is usually older and less reliable.

Expenditures:

Of the work planned for 2009, individual projects that equal or exceed \$100,000 are listed below in Table 2. These figures are also reflected in Table 1.

Table 2 – 2009 Individual Services Projects Equaling or Exceeding \$100,000

Description	Project Cost
	(\$ 000)
Subdivision developments	215.0
Total	215.0

The estimated requirements for new services in 2009 are based on the known customer requests as well as historical data on connections of similar services.

The Applicant performs an economic evaluation (prepared in accordance with prescribed valuation methodologies) of service projects that require new facilities to be built on the distribution system or those that require an increase in capacity of the distribution system. The economic evaluation is used to determine if the stream of future revenues associated with the expansion is sufficient to pay for the capital cost and ongoing maintenance costs of the distribution system expansion to supply the service. If there is a shortfall between the present value of the projected costs and revenues, the customer pays the difference as a capital contribution in accordance with the Distribution System Code.

1.1.1. Commercial/Industrial Services: Budget: \$351,000 less capital contributions

The estimated requirements for new three phase services in 2009 are based on the known customer requests as well as historical data on connections of similar services.

The cost of new services collected from customers in the form of capital contributions is estimated at \$351,000. This amount is included in Westario Power's budgeted spending on Distribution Plant-related projects, however it is not included in WPI's rate base as this is 100% contributed capital.

1.1.2. Low Voltage Services: Budget: \$205,800 less capital contributions

The estimated requirements for new services in 2009 are based on the known customer requests as well as historical data on connections of similar services.

1 The cost of new services collected from customers in the form of capital contributions is
2 estimated at \$50,000. This amount is included in Westario Power's budgeted spending on
3 Distribution Plant-related projects, however it is not included in WPI's rate base .
4

5 **1.1.3. Subdivision Development:** Budget: \$215,000 less capital contributions

6 The work planned for 2009 includes approximately 4 subdivisions; providing facilities for new
7 residential services in those subdivisions.
8

9 The cost of new services collected from customers in the form of capital contributions is
10 estimated at \$83,000. This amount is included in Westario Power's budgeted spending on
11 Distribution Plant-related projects, however it is not included in WPI's rate base.
12

13 **1.2. 2009 Public and Worker Safety:**

14 Total Cost: \$1,607,500
15

16 **Description:**

17 These projects involve the replacement of deteriorated or substandard distribution infrastructure
18 and electrical equipment that pose a serious and likely risk to public and worker safety.
19

20 Public and Worker Safety projects can involve either the complete rebuilding of deteriorated
21 lines or the selective replacement of line components. Renewal decisions are based on the
22 need to maintain the integrity, safety and reliability of the system.
23

24 Approximately 90% of the total \$1,607,500 cost can be attributed to two projects described
25 below.
26

27 **Justification**

28 The Applicant maintains its distribution plant according to an assessment that uses a
29 combination of time based and condition based maintenance inspections. Despite performing
30 maintenance, these distribution assets are ultimately failing and have reached a point where no

reasonable amount of maintenance will improve the reliability, maintainability and especially the safety of the equipment.

Identified projects are scored against a pre-established set of criteria in categories including reliability, public safety, worker safety, and prudence of expense. See Westario Power Asset Management Policy in Exhibit 2, Tab 3, Schedule 1.

Projects in this group, for the most part, are driven by safety hazards and the plant rebuild will ultimately benefit customer reliability. After a rebuild, distribution plant assets that are designed to current standards are more maintainable and reduce safety risks to the general public and workers. In some cases the severity of the hazards is high. Westario Power has taken a managed approach to prioritizing and replacement of such plant.

Expenditures

Table 3 below summarizes the projected 2009 rebuilds and conversions expenditures. Of the work planned for 2009, individual projects that equal or exceed \$100,000 are listed in Table 3. These figures are also reflected in Table 1 above.

Table 3 - 2009 Individual Renewal Projects Equaling or Exceeding \$100,000

Description	Project Cost
	(\$000)
Pole Line replacement program	892.9
No. 6 Copper replacement program	549.9
Total	1,442.8

The project budget estimate is based on detailed engineering estimates of the individual project components.

Some capital projects are multi-year projects.

1 **1.2.1. Pole Line Replacement:**

2 Every LDC will, from time-to-time, require investments in replacement existing pole lines. Pole
3 line replacements are undertaken when existing lines and feeders are found to have insufficient
4 capacity to back-up adjacent feeders and support their current loading demands, or have
5 reached end of life, or are difficult to maintain and pose considerable and on-going reliability
6 issues.

7
8 **Capacity:** Load growth caused by new customer connections and increased demand of existing
9 customers over time can result in a need for capacity improvements on the system. Projects
10 take the form of new or upgraded feeders. These projects are not customer-specific, but rather,
11 they benefit many customers. Furthermore, the ability to transfer loads from one feeder to
12 another allows greater safety margins, and improved power restoration than might occur if loads
13 could not be transferred. Severe damage to pole lines that interrupt large number of customers,
14 from vehicular accidents for instance, can be managed better when adjacent feeders have been
15 built to support the capacity. This improves public and worker safety, and contributes to quickly
16 restoring power.

17
18 **Renewal** projects are completed when assets reach their end of useful life and must be
19 replaced. WPI is currently undertaking field asset collection of its plant. Those projects
20 identified have been visual inspected, and replacement of the assets is based on these
21 inspections. In some cases the projects involve spot replacement of assets; in others, the
22 projects involve complete asset replacement within an identified project scope.

23
24 When assets in an identified project are replaced, the pole line is examined to determine
25 utilization and where required, high capacity wire is utilized in the new build. Utilizing high
26 capacity wire does not increase the cost of the project, and provides added benefits including
27 improved fault current sensing, and reduced system losses. New assets require less
28 maintenance, deliver better reliability and reduce safety risks to the general public.

29

1 In most cases, the pole line replacements have reached end of life and are deteriorating. Public
2 safety considerations are becoming increasingly more important, as these assets age and pose
3 public safety concerns.

4
5 **Reliability:** The main driver for these investments is an analysis of what measures could be
6 undertaken to improve WPIs reliability performance as measured by SAIDI, SAIFI and CAIDI
7 indices. These indices are indicators of the reliability of WPI's distribution system. These
8 activities will support maintenance of or improvement to the Service Quality Indices measured
9 and submitted to the OEB each year by WPI.

10
11 WPI's pole-line replacements will be an on-going budget item. Field asset collection will provide
12 vital system information and support decision making. This is a prudent action, as the
13 distribution system must be continually monitored for optimal performance.

14
15 WPI manages pole-line replacements with the objective of maximizing safety and reliability,
16 while minimizing costs. WPI prioritizes these objectives using the scoring matrix in our Asset
17 Planning policy; and objectives these include:

- 18 1. Prudence of Expense;
- 19 2. Safety (replacement in communities and where public risk is high);
- 20 3. End of Life;
- 21 4. System Reliability

22
23 For the reasons set out above, there is clearly a need for WPI to continue to assess and replace
24 pole-lines. If WPI's pole-lines are not replaced as the conditions warrant, the following can be
25 expected:

- 26 • the undersized conductor will continue to place operating constraints on the distribution
27 system, leading to:
 - 28 • the inability to quickly and effectively restore power by transferring loads, and
 - 29 • the increased line losses as undersized wire is made to carry overcapacity loads
- 30 • as the aged pole lines continue to be utilized, WPI's line personnel will be exposed to
31 increasing safety risk due to more frequent maintenance calls.

1.2.2. No. 6 Copper Replacement:

In the past No 6 Copper primary wire was an inexpensive solution for extending power lines to areas with small energy demands. These areas are now experiencing load growth and feeder extensions off the No 6 copper wire.

Unlike an all-aluminum wire or an ACSR (aluminum conductor steel reinforced) wire, No 6 copper wire is a solid, single strand of extruded solid conductor. It is general industry knowledge that No 6 copper conductor grows brittle over time and this wire is undersized for the average load. No 6 copper wire poses a public and worker safety issue should the wire break and fall. Westario Power has experienced No 6 copper wire fall incidents not related to weather events that are due to the brittleness of the wire.

This potential for wire fall incidents results in a significant safety risk to line workers and the public arising from the higher probability of line breaks. As a result, efforts have been made throughout the industry to remove No 6 copper wire from service.

Two other significant operational issues arise for the continued use of No 6 copper wire: the conductor size directly affects wire resistance, leading to:

- Line losses, and
- Improper fault current protection.

1. Line Losses

Because of the small cross-sectional diameter of the wire, this wire has high electrical resistance. As loads increase, and more current pass through No 6 copper wire sections, line resistance losses increase. Energy losses from wire resistance usually lead to heating of the wire. This resistance is proportional to the square of the current passing through the line. Proactive replacement of the No 6 copper wire will help reduce line losses.

2. **Improper Fault Current Protection**

As above, the small cross-sectional diameter of the wire means high electrical resistance. Fault protection equipment at the substation is designed to sense a line fall when there is a sudden and continuous increase in line current. The high wire resistance effectively attenuates the line currents. As a result the fault current protection equipment at the substation does not sense the fault current, and the substation fault protection devices do not operate to isolate the line.

Worker and public safety is highly compromised when the high resistance of the No 6 copper wire causes fault current protection equipment to not sense the high line currents; and therefore do not isolate fallen lines.

Presently, while working on No 6 copper lines, WPI Line Personnel assess the condition of its No 6 copper wire before working on the line. Should no visible defects be found, the Line Personnel will be working on the No 6 copper wire. However, a few cases of wire falls have occurred when no visible defects were present.

This is a cause for concern, not just for WPI Personnel who would be in the "line of fire" during a line fall incident, but also for the Public passing by. Based on these conditions, WPI undertook to survey its territory for No 6 copper lines.

Since its inception, Westario Power Inc has not used No 6 copper wire. Nevertheless, the predecessor utilities did use this wire, in many instances. Because of industry knowledge, historical observations, age of the conductor and operational experience, WPI concluded that its system composed of No 6 copper wire needed to be replaced and as a result, it WPI will commence this program in 2009.

Unfortunately, record keeping for the predecessor was poor, and identification of the wire was a long process involving visual inspections. Lines built of No 6 copper wire have been identified and WPI is undertaking a multi-year approach to the complete elimination of this wire.

1 Concurrent with the commencement of the No 6 copper wire replacement program, WPI has
2 discussed No 6 copper wire with all line personnel at safety meetings in order to ensure worker
3 safety.

4
5 The year 2009 will mark the first year of an aggressive program to eliminate No 6 copper wire in
6 Westario Power's service territory. WPI anticipates the duration of conductor replacement
7 program to be about 10 years. The timetables will be reviewed from year-to-year to determine
8 adequacy. The availability of resources and the amount of wire to be replaced make it difficult
9 for WPI to complete the program in less than 10 years. As 2009 will be the first year of active
10 and aggressive replacement of the No 6 copper wire, WPI believes its ten-year timeframe for
11 this program is reasonable.

12
13 WPI manages it's the No 6 wire replacement program with the objective of maximizing safety
14 and reliability, while minimizing costs. WPI prioritizes these objectives using the scoring matrix
15 in our Asset Planning policy; and these include:

- 16 1. Prudence of Expense;
17 2. Safety (replacement in communities and where public risk is high);
18 3. End of Life;
19 4. System Reliability

20
21 For the reasons set out above, there is clearly a need for WPI to replace the No6 copper wire. If
22 WPI's No 6 copper wire is not replaced, the following can be expected:

- 23 • the brittle conductor will continue to fall unexpectedly,
24 • as the brittle wire continues to be utilized, WPI's line personnel will be exposed to
25 increasing safety risk due to more frequent maintenance calls and the inherent danger of
26 working on and around the brittle wire;
27 • public safety will be jeopardized;
28 • reliability will be affected (i.e. there will be an increasing amount of outages);
29 • maintenance costs to repair breaks will increase; and
30 • the possibility of damages to public and private property caused by broken wire will
31 increase.

1 **1.3. System Reliability Projects:**

2 Total Cost: \$400,400

3
4 **Description:**

5 The primary driver for these projects is service interruptions caused by first contingency
6 equipment failures that cannot be restored through switching to alternative feeders or
7 substations.

8
9 System Reliability projects can involve the complete rebuilding of lines, installing switching
10 equipment or building backup loops on the distribution system. System Reliability projects are
11 scored against a pre-established set of criteria in categories including reliability, public
12 safety and worker safety, and prudence of expense. See Westario Power Asset
13 Management Policy in Exhibit 2, Tab 3, Schedule 1.

14
15 The work planned for 2009 includes approximately 3 System Reliability projects.

16
17 **Justification**

18 By considering the risk associated with the failure of assets, The Applicant makes prudent
19 investment decisions to achieve high levels of reliability and optimizing the utilization of its
20 assets.

21
22 Projects in this group, for the most part, benefit customer reliability. After a System Reliability
23 project is completed, the distribution system is more flexible in terms of its capability to have
24 service restored through switching operations. Most plant in System Reliability projects are at
25 end of life, are difficult to maintain, and failures would cause prolonged outages.

26
27 **Expenditures**

28 The projected 2009 security project expenditures total \$400,400

29 Of the work planned for 2009, individual projects that equal or exceed \$100,000 are shown in
30 Table 4. These figures are also reflected in Table 1 above.

Table 4 - 2009 Individual System Reliability Projects Equaling or Exceeding \$100,000

Description	Project Cost
	<u>(\$000)</u>
Defective Pole Replacements	159.7
Harriston MS1 Contingency Supply	127.2
Wingham MS1 Substation recloser replacement	<u>113.5</u>
Total	\$400.4

The project budget estimate is based on detailed engineering estimates of the individual project components.

Some capital projects in the System Reliability project pool are multi-year projects.

Individual Project Description

1.3.1. Defective pole replacements:

Each year Westario Power identifies and proactively replaces defective poles. These poles are at risk of breaking from high winds and ice loading, placing the public at a significant safety risk, as well as adversely affecting system reliability. Many of the poles are on circuits that deliver power to commercial and industrial customers, whose business would be negatively affected if there was no program to deal with these poles.

Predecessor utilities did not have a defective pole replacement program. Many poles are in excess of 40 years old. Poles targeted for proactive replacement have excessive shell rot, and in most cases are at end of their life. WPI's on-going field data collection will provide vital system information and support decision making. This is a prudent action, as the distribution system must be continually monitored for optimal plant replacement.

Poles identified for replacement are individual poles, or groups of up to 5 poles along a line. The identification of poles to be replaced is by visual inspection. Expensive testing and analysis is unnecessary as the age of plant, physical condition, and decay clearly distinguish these poles for replacement. WPI's pole replacements will be an on-going budget item.

Poles brought down by high winds cause hardship to our customers, and negatively affect Westario Power's reliability statistics. Furthermore, these poles represent a public and worker safety hazard.

WPI manages wood pole replacements with the objective of maximizing safety and reliability, while minimizing costs. WPI prioritizes these objectives using the scoring matrix in our *Asset Planning* policy; and these objectives these include:

5. Prudence of Expense;
6. Safety (replacement in communities and where public risk is high);
7. End of Life;
8. System Reliability, etc.

For the reasons set out above, there is clearly a need for WPI to proactively replace defective poles. If WPI's defective poles are not proactively replaced, the following can be expected:

- the defective poles continue to break,
- as the defective poles continue to be utilized, WPI's line personnel will be exposed to increasing safety risk due to more frequent maintenance calls and the inherent danger of working on and around defective poles;
- public safety will be jeopardized;
- reliability will be affected (i.e. there will be an increasing amount of outages);
- maintenance costs to repair broken poles will increase; and
- the possibility of damages to public and private property caused by broken poles will increase.

1.3.2. Wingham MS1 Recloser Replacements

This project is to replace all feeder protection on the Wingham MS1 with reclosers. The existing arrangement uses primary high voltage fuses for feeder protection. As a result, the feeders are incapable of momentarily tripping to clear faults, leading to single-phasing conditions on the distribution voltage and seriously affecting customer voltage quality. By installing properly sized

1 and coordinated reclosers, system reliability will be improved and operational issues will be
2 addressed.

3 4 **1.3.3. Harriston MS1 Contingency Supply**

5 The Town of Harriston is the only Westario Power community served by a 13800/8000 V
6 distribution system. Westario Power does not own a spare 13800/8000 V substation and there
7 is no alternative supply. This project involves installing a spare substation, acquired in 2008, at
8 the existing substation site. The substation will be connected to the 44kV sub transmission
9 system to provide a contingency supply.

10 11 **Revenue Metering**

12
13 Total 2009 Capital Budget: \$30,000
14

15 **Description**

16 Measurement Canada requires that revenue meters be recertified for measuring accuracy on a
17 regular basis. Some meter types are no longer supported by certified Meter Service Providers,
18 and cannot be recertified. This project will allow Westario Power to acquire new electronic
19 meters to replace obsolete meters.

20 21 **Justification**

22 Measurement Canada has reduced the seal duration on certain types of thermal meters.
23 Recertifying these old meter types will only serve to accelerate meter operating expenses as
24 these meters are to be recertified more often. Replacing these older type meters with new
25 electronic meters will allow a longer duration between recertification cycles and place more
26 accurate electronic meters in service.

3. General Plant

Total Cost \$254,700

Introduction:

General plant includes assets such as buildings, computer hardware and software, office, furniture and equipment, transportation equipment, communications equipment and tools.

Expenditures

Of the general plant additions that are planned for 2009, individual projects that equal or exceed \$15,000 are shown in Table 5.

Table 5 – Individual 2009 General Plant Additions Equaling or Exceeding \$15,000

Description	Project Cost
	<u>(\$000)</u>
Outage Management software	20
Pole Line structural modeling software	15
Pick Up Truck	30
Fork Lift	72.5
Chipper	42
Yard Lighting	16
Total	195.5

3.1 Computer Hardware and Software

Computer Hardware

Total 2009 Capital Budget: \$11,800

Description

Computer equipment is used in all departments of utility operations and is a key enabler in The Applicant's initiatives to improve reliability, improve customer service and reduce costs.

New and replacement Computer hardware consists of the following equipment:

- Desktops;
- Laptops;
- Monitors;
- Servers;
- Keyboards;
- Printers and;
- Scanners;

It is common industry practice to keep both the hardware and software environments up to date. Increased incidence of hardware failure, reduced technical support, new technical standards and higher performance requirements of current operating systems and applications drive this lifecycle.

Other benefits of replacing computer equipment and adding new equipment are:

- Reducing the dependence on IT resources to support older equipment;
- Taking advantage of new technologies and increasing server utilization;
- Empowering employees to be more productive with the right equipment to do their jobs;
- Improving access to data and other information;
- Adhering to best practices; and
- Allowing for growth

Computer Software

Total 2009 Capital Budget: \$35,400

Description

Computer software, whether operating system software or application software, are programs written in machine-readable languages, that control the operations of hardware or that enable users to perform certain tasks on computers.

The operating system software controls the hardware and manages its internal functions: controls input, output and storage and, handles its interaction with application programs. Application software enables users to accomplish particular tasks.

Justification

Today, the functioning of computer software is tied closely into the hardware it resides on and it is important that the specification of any PC or Server is appropriate for the software being installed.

Benefits of adding or replacing computer software:

- Improvements in productivity from software enhancements;
- Empowering employees with the latest software technologies;
- Keeping up to date with industry standards;
- Ease of integration to other applications;
- Reduced costs using common operating system;
- Taking advantage of higher levels of security;
- Reduced dependence on IT resources; and
- Improved tools for web development/design.

Adding and replacing computer software systems is necessary to support the running of all application programs. Software provides the support necessary for computers to interact with each other. Business Applications software processes transactions that are essential to running the business.

The projected 2009 expenditures total \$35,400. Of the expenditures for 2009, individual projects that are equal to or exceed \$15,000 are shown in Table 6.

Table 6 - 2009 Individual Computer Hardware and Software Projects Equaling or Exceeding \$15,000.

Expenditures are also included in Table 5 above.

Description	Project Cost
	(\$000)
Outage Management software	20
Pole Line structural modeling software	<u>15</u>
Total	35

Outage Management software

This software will allow Westario Power to manage and automate the manual paper process brought on by the loss of supply and other customer complaints. The system will be integrated to the existing GIS system to provide accurate tracking of cause and sub-cause of an outage. The software will assist to manage customer notifications and call backs efficiently. Business reports and system indices (SAIDI, SAIFI, CAIDI, CAIFI) can be generated on demand. The software will integrate to the GIS system to improve the efficiency, availability and accuracy of data.

Pole Line structural modeling software

Westario Power has standardized its construction using steel poles. Steel poles are readily recyclable, unlike treated wood or concrete which require special disposal. Steel poles are lightweight and have the structural strength of wood poles. The Ontario distribution system regulations require that Westario demonstrate the structural strength of its designs using steel poles. This software will provide Westario Power with the tools to provide assurance to the regulators to demonstrate the integrity of our designs.

3.2. Transportation Related Equipment

Vehicle and Related Equipment Replacement and Modification:

Total 2009 Capital Budget: \$30,000

Description

This project provides for the replacement of one pick-up truck to support the construction and maintenance of the electricity distribution system for Westario Power.

Justification

This project is justified based on the need to maintain vehicles functionality and provide safe, reliable tools and fleet equipment.

Typically, pick-up trucks are replaced every ten years.

Expenditure

The projected 2009 expenditures total \$30,000. Of the expenditures for 2009, individual projects that are equal to or exceed \$15,000 are shown in Table 7.

Table 7 - 2009 Individual Vehicle and Related Equipment Replacement Expenditures Equaling or Exceeding \$15,000. This expenditure is reflected in Table 5 above.

Expenditures	Number of Units	2009 (\$000)
Pick up truck	1	<u>30</u>
Total		30

Table 8 – Summary of 2008 and 2009 fleet expenditures:

Expenditures	2008 budget	2009 budget
Vehicles	\$95,000	\$30,000

3.3. Tools and Equipment

Total 2009 Capital Budget: **\$45,000**

Description

Capital replacement of tools and equipment supports a safe work environment by replacing tools and equipment in a timely manner and addresses newer more ergonomically friendly tools.

Justification

Large Tools

Large tools are acquired to manage the distribution system. The timely replacement of tools and equipment that are worn, or have come to the end of their useful life, with newer and more ergonomically friendly tools and equipment supports a safe work environment for Westario Power's employees.

Expenditure

The projected 2009 expenditures total \$45,000. There are no individual tools exceeding \$15,000.

3.4. Stores Equipment

Total 2009 Capital Budget: **\$72,500**

Description

This expenditure provides for replacement of equipment in supporting a safe and efficient work environment for the stores operation that supports the construction and maintenance of the electricity distribution system for Westario Power.

Justification

Fork Lift

In 2009, the fork lift will be 37 years old. An assessment of the fork lift by a licensed repair contractor indicates that the brakes are failing, and the transmission is failing. A new fork lift is required to continue to perform warehousing operations, and retire the existing unit which has reached the end of life.

Expenditure

The projected 2009 expenditures total \$72,500. Of the expenditures for 2009, individual projects that are equal to or exceed \$15,000 are shown in Table 9.

Table 9 - 2009 Individual Stores Equipment Expenditures Equaling or Exceeding \$15,000. This expenditure is reflected in Table 5 above.

Description	Project Cost
	(\$000)
Fork Lift	72.5
Total	72.5

3.5. Power Operated Equipment

Total 2009 Capital Budget: **\$42,000**

Description

This expenditure provides for replacement of equipment in supporting a safe and efficient work environment for the construction and maintenance of the electricity distribution system for Westario Power.

Justification

Chipper

This project is justified based on the need to maintain power operated equipment functionality and provide safe, reliable tools for line operations.

Typically, chippers are replaced every ten to fifteen years depending on wear and tear.

Expenditure

The projected 2009 expenditures total \$42,000. Of the expenditures for 2009, individual projects that are equal to or exceed \$15,000 are shown in Table 10.

Table 10 - 2009 Individual Power Operated Equipment Expenditures Equaling or Exceeding \$15,000.
This expenditure is reflected in Table 5 above.

Description	Project Cost
	<u>(\$000)</u>
Chipper	42
Total	42

3.6. Buildings and Fixtures

Total 2009 Capital Budget: **\$16,000**

Description

This expenditure provides for an addition to the operations and stores yard in supporting a safe and efficient work environment for the construction and maintenance of the electricity distribution system for Westario Power.

Justification

Yard Lighting

Currently there is no outdoor lighting in the fenced yard at the operation facility. Yard lighting will provide additional employee safety and security when entering the yard during after hours storm related or emergency works in order to retrieve stores related items. Yard lighting will also provide additional security on all stores related items.

Expenditure

The projected 2009 expenditures total \$16,000. Of the expenditures for 2009, individual projects that are equal to or exceed \$15,000 are shown in Table 11.

Table 11 - 2009 Building and Fixtures Expenditures Equaling or Exceeding \$15,000. This expenditure is reflected in Table 5 above.

Description	Project Cost
	(\$000)
Yard Lighting	16
Total	16

3.7. Office Furniture and Equipment

Total 2009 Capital Budget: \$2,000

Description

This expenditure provides for an addition to administrative offices in supporting a safe and efficient work environment for Westario Power.

Justification

To provide additional filing cabinets and shelving for documentation that is maintained under the Applicant's file retention policy.

Expenditure

The projected 2009 expenditures total \$2,000.



WESTARIO POWER POLICIES AND PROCEDURES

Asset Management

Document No.: WPI-020-08

Page: 1 of 15

Issued: July 11, 2008

Issue No.: 1.0

Reviewed:

1. Purpose

The purpose of this document is to describe Westario Power's approach to asset management.

This work procedure is to be read in conjunction with the relevant regulations under the Occupational Health and Safety Act, the EU&SA rulebook, and relevant Westario Power Inc. safe work practices and procedures.

This Business Procedure shall also be interpreted within the context of the following documents, which define how electrical connections shall be administered:

- The Distribution System Code of Ontario, and
- Westario Power's Conditions of Service, and
- Westario Power's Business Procedures, and
- The Ontario Electrical Safety Code.

2. Responsibility

Manager of System Reliability is responsible for the administration of this procedure, and may delegate tasks as outlined below.

3. Definitions

Asset Management	Asset management is a systematic process of maintaining, upgrading, and operating physical assets cost-effectively. It combines engineering principles with sound business practices and economic theory, and it provides tools to facilitate a more organized, logical approach to decision-making. Thus, asset management provides a framework for handling both short- and long-range planning.
Fulfill Customer Demand	A difficult to-plan-for endeavour, fulfilling customer demand is the practice of providing electrical supply to fulfill customers electrical service requests in a timely and effective manner.
Operations	Operations is that part of the business for which no productive work is achieved, but without which customer and business objectives cannot be met. Operations include underground cable locating, answering technical inquiries, and repairing and managing the fleet of vehicles.
Maintenance	Maintenance is that part of the business for which pro-active, re-active, and emergency work is performed for the safe and efficient management of the distribution system.



WESTARIO POWER POLICIES AND PROCEDURES

Asset Management

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Regulatory Requirement	A function or task that is recommended and/or required by a regulatory body for the safe and efficient management of the distribution system. The regulatory body may be, but are not limited to, the Ministry of Labour, Ontario Energy Board, The Electrical Safety Authority, etc.
Safety	Safety refers to systems and practices, tools, barriers, and controls that prevent the unintentional release of mechanical, electrical, or chemical energy. Westario Power Inc. is a member of the Electrical & Utility Safety Association and promotes a safe and healthy workplace and home life for all employees; and is dedicated to providing a safe and efficient distribution system for our customers.
System Reliability	System reliability is the management of system outages, voltage control, feeder optimization, and effective planning resulting in the efficient and cost effective operation of the distribution system.

4. Asset Management Approach to System Planning

An asset management approach to system planning can provide the accounting equivalent of a comprehensive inventory control, property management, logistics management and maintenance planning system for Westario Power Inc.

Asset management is a process of providing a centralized oversight of infrastructure investment decisions to maximize system performance, profitably grow the business, and balance customer and shareholder value. Critical elements include:

- an understanding of accountabilities associated with the asset management approach
- a long-range work plan that addresses system needs and difficulties
- a process to prioritize and control the release of work
- an alignment of the work, financials, and resources
- well-defined maintenance and reliability programs
- a standardized engineering design process
- a seamless interface with work management
- a clear agreement on expectations by all parties documented in a service level agreement
- metrics and scorecards to monitor execution relative to the plan
- work defined in cost per unit.

As a result, new ways to achieve objectives have been developed by:

- Defining and undertaking works with a consistent work priority
- Levelling and bundling work to minimize costs
- Achieving efficiencies from consistent processes and standards
- Comparing spending versus forecasts to redeploy savings
- Communicating risks with alternative investment decisions.



WESTARIO POWER POLICIES AND PROCEDURES

Asset Management

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Asset Management provides ready access to quantitative and qualitative data and allows decision makers to more readily identify and focus on key issues. Furthermore, the ability to weigh and articulate the impact of choosing one alternative over another is delineated. A fact-based, reproducible, systematic approach enhances the dialogue among decision-makers regarding capital investment levels. In turn, these benefits help increase the effectiveness and efficiency with which field operations personnel perform their jobs.

5. Field Asset Collection

Westario Power will dedicate resources to collect detailed field asset information as part of its asset management plan. The detailed field asset information will be submitted to the Design Drafter for review and input into the Asset Management Database.

The Asset Management Plan is aimed at distributions system assets, and not substation, which are handled separately. See Business Procedure SR-021-08 *Substation Maintenance Program*. More particularly, collection of field asset data also serves to fulfill Distribution System Code regulatory requirements for field inspection of devices.

The actual inspection requirements for Distribution System Assets are outlined in Business Procedure SR-002-07 *Distribution System Inspection under Ontario Regulation 22/04*.

6. Future Plans for the Asset Database

Westario Power is currently in the asset collection phase. While some asset management can begin, it is preferable to collect all data of an asset class to best manage a formalized program. It is expected that the asset collecting should be completed by the end of 2010, if workload and labour force is maintained.

The asset management database will allow Westario Power to track yearly inspections as required under the Distribution System Code, plan and manage specific asset maintenance programs, and provide reporting and record keeping of those activities.

The rationale for collecting asset management data to answer some basic questions for Westario Power, such as:

- What do we own?
- Where is it?
- How is the asset connected to the distribution network?
- What are its characteristics?

Most assets utilized by Westario Power have no maintenance schedules. Some may require regular maintenance, and the asset database will assist in determining this. The asset management database will allow us to determine, and schedule maintenance activities, such as:

- Was it maintained, and if so, by who?
- When was the item been placed in service?



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- How much effort (work force and cost) is there to maintain?
- How well is the product supporting our business of delivering electricity?

Overall benefits to tracking asset performance include:

- Improved ability to meet regulatory demands for asset planning.
- Better design and control over the capital expense program.
- Standardization of utility asset identification, information and processes involved in asset management.
- Reduced numbers and types of maintenance programs and activities in use at the utility.

7. Self-Funded Capital Projects

While it would be preferable have a complete inventory identifying all assets, this condition does not exist at this time. As described above, Westario Power has begun detailed field asset collection.

Westario Power has adopted a scoring matrix when identifying projects for consideration into a capital Replacement Program. The matrix is flexible, and while it shall be reviewed yearly, this review and change in scoring shall only be performed with the consent of the Departmental Manager. Should it be determined that the scoring need to be adjusted, a review of pending projects shall be subject to the modified scoring as soon as practicable.

A memo shall be issued to the President/CEO when the scoring matrix is altered. The purpose is to ensure transparency in the scoring process, and ensure both Executive and Finance are informed of the possible change in results.

Scoring of pending projects shall occur at least once per year when planning self-funded capital works. In some cases, lower ranked projects may be slotted ahead as it makes logical sense to complete works that generate high priority works in future years.

The scoring matrix is shown in Appendix A.

The Scoring Criterion or "how to uniformly apply the scoring" is shown in Appendix B. However, the categories of severity versus need are for illustrative purposes only. The descriptors may be adjusted for the particular project with the consent of the Departmental Manager.

Approved By

July 11, 2008

Appendix A -- Self-Funded Capital Projects Scoring Matrix

Criteria	Min Score	Min Criteria Description	Max Score	Max Criteria Description
Prudence of Expense	0	Where there is uncertainty whether the regulator will support or interveners will reasonably question the project's requirements the project shall receive the minimum score	15	Where the project is driven by legislative or regulatory compliance requirements or the assets are clearly necessary to supply customers, the project shall receive the maximum score
Public Safety	0	Where the project will have no impact on public safety the project shall receive the minimum score	15	Where the project is likely to eliminate a single public injury once every 10 years the project shall receive the maximum score
Worker Safety	0	Where the project will have no impact on worker safety the project shall receive the minimum score	15	Where the project is likely to eliminate a single worker injury once every 10 years, the project shall receive the maximum score
Environmental	0	Where the project will have no impact on the reduction of environmental risk the project shall receive the minimum score	10	Where the project is likely to eliminate a single environmental incident once every 10 years, the project shall receive the maximum score Note: Additional consideration to be given to system losses
Reliability	0	Where the project will have no impact on system reliability, the project shall receive the minimum score	10	Where the project is likely to eliminate a single system 4 hr outage to at least 200 customers once a year, the project shall receive the maximum score Note: Additional consideration to be given to multiple outage situations
Power Quality	0	Where the project will have no impact on voltage, the project shall receive the minimum score	5	Where the project will correct existing voltage concerns or problems for 200 or more customers, the project shall receive the maximum score. Note: Consideration also to be given to size of customers effected and the severity of the impact on the customer

Criteria	Min Score	Min Criteria Description	Max Score	Max Criteria Description
End of Life	0	Where the equipment still retains 50% or more of its life expectancy, the project shall receive the minimum score	10	Where the equipment is at end of life and is not expected to be operable for more than two more years, the project shall receive the maximum score
Maintainability	0	Where there will be no improvement in the maintainability of the system, the project shall receive the minimum score	5	Where there will be a substantial improvement in the maintainability of the system, the project shall receive the maximum score
Operability	0	Where there will be no improvement in the operability of the system, the project shall receive the minimum score	5	Where there will be a substantial improvement in the operability of the system, the project shall receive the maximum score
	0	Minimum	100	Maximum

Appendix B -- Scoring Criterion

Prudence of Expense describes whether the cost to perform project is or can be reasonable and defensibly justified. The conditions listed below are for guidance only. It is difficult to prepare a table to cover all possible device and field conditions.

Most Prudent	6 The expenditure can be shown to be most prudent, but there is no regulation requiring the work to be performed.	9 A system improvement that will save time, effort, and enhance efficiency.	12 An operationally important device whose costs are worth the savings in effort, operability or efficiency	15 Required to fulfill regulatory requirements, and is a most prudent expenditure given the condition of the device.
High	4 While the expenditure could be argued, there is no motivating driver to make the make the expenditure.	6 A system improvement whose payback costs are less than or equal to the previous device.	9 An operationally important device, whose costs are readily defensible	12 While the regulations stipulate the condition, the device is nearing end of life, and is marginally functional.
Moderately	2 The expenditure might be argued, but cannot be substantiated in regulation.	4 A system improvement whose are costs are high, and do not improve work methods or efficiency.	6 An operationally important device but whose costs do not improve system operability, or efficiency.	9 While the regulations stipulate the condition, the device has some useful life and is functional for the most part.
Least prudent	0 The expenditure cannot be justified, nor substantiated in regulations.	2 A system improvement whose cost cannot be justified.	4 An operationally important device whose cost cannot be justified.	6 While the regulations stipulate the condition, the device may have useful life and is functional.
	Not required	Nice-to-have	Operationally important	Regulatory Requirement

Public Safety describes the risk the general public is exposed to by the distribution system and its components. The risks may be obvious to the public, nor not.

Critical Risk	While not a requirement of any regulatory body, the risk of critical injury requires the LDC to act immediately.	9	The public recognizes the risk and the risk of critical injury or death, and/or catastrophic equipment damage is very high.	12	Contact will cause critical injury or death, and/or catastrophic equipment damage. The condition is a violation of safety regulations.	15
High Risk	A high risk to public safety but not a violation of any safety regulation.	6	The public recognizes the risk and the risk of injury, equipment damage of fire is high.	9	High risk of severe injury, equipment failure or fire. The condition is a violation of safety regulations.	12
Moderate Risk	A moderate risk to public safety but not a violation of any safety regulation.	3	The public views the condition as a safety hazard, while the actual risk is moderate.	6	The condition poses a moderate risk for public injury, equipment damage, or fire. The condition is a violation of safety regulations	9
Negligible Risk	Little or no risk to the public	0	Public views the condition as a safety issue, but the risk is low	3	Extremely low risk to public. The condition is away from public contact. The condition is a violation of safety regulations.	6
	Not regulated		Public Perception Issue		Regulatory Requirement	

Worker safety describes the risk Westario Power workers are exposed to by the distribution system and its components.

Critical Risk	9		12		15	
	While not a requirement of any regulatory body, the risk of critical injury to workers requires Westario Power to act immediately.		The workers recognize the risk and the risk of critical injury or death, and/or catastrophic equipment damage is very high.		Contact will cause critical injury or death, and/or catastrophic equipment damage. The condition is a violation of safety regulations.	
High Risk	6		9		12	
	A high risk to worker safety but not a violation of any safety regulation.		The workers recognize the risk; and the risk of injury, equipment damage or fire is high.		High risk of severe injury, equipment failure or fire. The condition is a violation of safety regulations.	
Moderate Risk	3		6		9	
	A moderate risk to worker safety but not a violation of any safety regulation.		The workers view the condition as a safety hazard, while the actual risk is moderate.		The condition poses a moderate risk for worker injury, equipment damage, or fire. The condition is a violation of safety regulations	
Negligible Risk	0		3		6	
	Little or no risk to workers		Workers view the condition as a safety issue, but the risk is low		Extremely low risk to workers. The condition is away from contact. The condition is a violation of safety regulations.	
		Not regulated	Recognized Issue		Regulatory Requirement	

Environmental describes risks to the natural environment. This includes air quality, water and soil quality, and how the condition affects the community and society.

High Risk (once per 10yrs)	5 A high risk to the environment but not a violation of any safety regulation.	7 Recognized that the condition has an environmental impact, and the risk is high.	10 High risk or severe risk to the environment. The condition, or when the condition occurs, is a violation of Regulations.
Moderate Risk (once per 20yrs)	2 A moderate risk to the environment but not a violation of any safety regulation.	5 Recognized that the condition has an environmental impact, but the risk is moderate.	7 The condition poses a moderate risk to the environment. The condition, or when the condition occurs, is a violation of Regulations.
Negligible Risk (once per 50yrs)	0 Little or no risk to the environment	2 Recognized that the condition has an environmental impact, but the risk is low	5 Extremely low risk the environment. The condition, or when the condition occurs, is a violation of Regulations.
	Not regulated	Recognized Issue	Regulatory Requirement

Reliability - describes how the project will improve delivery of power to customers by reducing system interruptions, or improving restoration times.

High Impact (200 or more customers affected)	5		7		10	
	A high impact to system reliability, but cause is difficult to control.		Recognized that the condition should to be rectified. Directly influences SQLs.		A Regulatory Requirement with high impact on system reliability. Directly influences SQLs.	
Moderate Impact (100 to 200 customers affected)	2		5		7	
	A moderate impact on system reliability.		Recognized that the condition should to be rectified. The impact on system reliability is moderate.		A Regulatory Requirement with moderate impact on system reliability. Directly influences SQLs.	
Negligible Impact (less than 100 customers affected)	0		2		5	
	Little or no impact to system reliability		Recognized that the condition should be rectified, but the impact on system reliability is low		A Regulatory Requirement with low impact on system reliability.	
		Not regulated - Nice-to-have	Recognized condition - Should-Do		Regulatory Requirement - Shall-Do	

Power Quality describes the voltage delivered to the customer, and the presence of harmonics or “noise” on the delivered power.

High Impact	Recognized that the condition should to be rectified. May lead to customer insurance claim.	2	A CSA Voltage or a harmonics issue; causing damage to customer's equipment.	5
Low Impact	Low risk condition that neither affects voltage ranges or harmonics.	0	A CSA Voltage or a harmonics issue with moderate impact on customer's equipment. May lead to an insurance claim/	2
	Recognized condition		Regulatory Requirement	

End of Life refers to equipment is at end of its manufacturers suggested life span.

High Impact	5 Device is at mid-life and is old technology. Its failure, while unlikely, would have high impact on distribution system.	7 Recognized that the device is aged. The impact on distribution system of not replacing is high. Directly influences SQLs.	10 Recognized that the device is failing. The impact on distribution system of not replacing is high. Directly influences SQLs.
Moderate Impact	2 Device is at mid-life and is old technology. Its failure, while unlikely, would have moderate impact on distribution system.	5 Recognized that the condition should to be rectified. The impact on system reliability is moderate.	7 Recognized that the device is failing. The impact on distribution system of not replacing is moderate. Directly influences SQLs.
Negligible Impact	0 No need to replace device. Failure, if it occurs, would have little effect on the distribution system.	2 Recognized that the device is aged, but the impact on distribution system of not replacing is low	5 Device is failing, but the impact on the distribution system of not replacing is low.
	At least mid-life	At End of Life	End of Life - Failing

Maintainability refers to where there will be a substantial improvement in the maintainability of the system.

Significant Improvement in maintainability	Device is easier to maintain, but no easier to inspect.	2	Device is easier to inspect and easier to maintain	5
	Device is no easier to inspect or maintain as the previous device.	0	Device is easier to inspect but no easier to maintain.	2
No improvement in ease of inspection		Significant improvement in ease of inspection		

Operability refers to a substantial improvement in the line switching, load transferring, or back-up/alternate supply of the system.

Significant Improvement in system operability	Device improves system operability but provides no improved access by field personnel.	2	Device improves system operability and is easier to access by field personnel.	5
	Device does not improve system operability and provides no improved access by field personnel.	0		2
No Improvement in system operability	No improvement in device access		Significant improvement in device access	

Leave to Construction (under Section 92)

In the 2009 Test Year WPI does not anticipate seeking leave of the Board under section 92 of
The Ontario Energy Board Act, 1998.

Fixed Assets and Associated Depreciation Rates

Property, plant and equipment are recorded at amortized cost. Amortization is provided on a straight-line basis divided equally over the following number of years:

OEB Account and Description of Account	No. of Years
1805-Land	N/A
1808-Buildings and Fixtures	25 and 50
1820-Distribution Station Equipment - Normally Primary below 50 kV	33
1830-Poles, Towers and Fixtures	25
1835-Overhead Conductors and Devices	25
1840-Underground Conduit	25
1845-Underground Conductors and Devices	25
1850-Line Transformers	25
1855-Services	25
1860-Meters	25
1915-Office Furniture and Equipment	10
1920-Computer Equipment – Hardware	5
1925-Computer Software	3 and 5
1930-Transportation Equipment	8
1935-Stores Equipment	10
1940-Tools, Shop and Garage Equipment	10
1945-Measurement and Testing Equipment	10
1950-Power Operated Equipment	10
1955-Communication Equipment	5
1960-Miscellaneous Equipment	10
1975-Load Management Controls - Utility Premises	25
1995-Contributions and Grants – Credit	25

For accounting purposes, WPI does not use the half year rule for determining depreciation related to its capital expenditures, however, WPI does use the half year rule with respect to income tax filing as required by the *Income Tax Act*.

- 1 Pursuant to Board Decision EB2007-0761 (Lakefront Utilities Inc.), WPI has recalculated
- 2 depreciation for this application using the half-year rule effective January 1, 2005 in keeping
- 3 consistent with the Board's practice for determining rate base.

Materiality Analysis on Capital Additions

	2009 Test	2008 Bridge	2007 Actual	2006 Actual	2006 EDR Approved
Total Gross Assets.	\$42,207,707	\$39,636,807	\$34,317,175	\$29,541,818	\$23,478,098
Percent	1%	1%	1%	1%	1%
Threshold	\$422,077	\$396,368	\$343,171	\$295,418	\$234,780

Materiality Analysis on Capital Additions

2009 Test

Project Description: No 6 Copper Replacement

Need: In the past No. 6 copper primary wire was an inexpensive solution for extending power lines to areas with small energy demands. These areas are now experiencing load growth and feeder extensions off the No. 6 primary wire. The wire has grown brittle and is undersized for the average load.

This wire type poses a public and worker safety issue should the wire break and fall. Because of the smallness of the wire, the protection equipment at the substation does not sense the fault and does not operate to isolate the line.

The No 6 copper replacement program is a group of separate and distinct projects. For 2009, nine distinct projects in six towns have been identified for inclusion in the program. Overall, 97 distinct No 6 copper replacement projects in eleven Westario Power municipalities have been identified.

The No. 6 copper conductor will be replaced with a minimum conductors size of 1/0 ACSR. This will help to reduce line losses due to the lower line resistance of the larger conductor.

Scope: Replace No 6 copper wire, and replace aged poles, transformers, and line hardware as identified in the project scope.

Self-Funded Capital Works Scoring Matrix Score: 69 to 90

Capital Costs: \$892,900

Start Dates: Various sites - March 20, 2009 to August 21, 2009

In-Service Dates: Various sites - March 27, 2009 to September 11, 2009

Project Description: Pole Line Rebuild Projects

These projects are identified for inclusion as they serve the purpose of increasing reliability, increasing feeder capacity, reducing line losses, and/or the condition of the line and the severe impact of its failure on customer interruptions make the work necessary.

Need: Usually, pole line work is a particular project serving a particular need. In 2009, feeder rebuilds are planned for back-lot replacement in Hanover, pole-line replacements Kincardine and Teeswater and Port Elgin.

The Pole Line Rebuild program is a group of separate and distinct projects. For 2009, five distinct projects in five towns have been identified for inclusion in the program. Overall, 36 distinct pole line rebuild projects in eleven Westario Power municipalities have been identified.

Scope: Replace overhead poles, lines and transformers, as identified in the project scope.

Self-Funded Capital Works Scoring Matrix Score: 70 to 82

Capital Costs: \$549,900

Start Dates: Various sites – May 29, 2009 to September 4, 2009

In-Service Dates: Various sites – May 15, 2009 to September 25, 2009

1 **2008 Bridge Year**

2
3 **Project Description:** 5kV Cable Replacement

4 In the past 5kV butyl rubber cable and "Pole Trans" transformers we used to service residential
5 neighborhoods. The 5 kV cable is direct buried and is failing as it has surpassed its 30 year
6 lifespan. The Pole Tran transformers are heavily loaded and extremely congested, posing
7 worker safety issues.

8
9 **Need:** Emergency directional boring is expensive and, depending on the season, may not be
10 practical. In the past, temporary pole lines have had to be built to restore power when
11 conditions were not conducive to preferred repair techniques. Such temporary works are
12 expensive and delay restoring power to customers.

13
14 In 2008 the 5kV Cable Replacement Program is two separate and distinct projects, one in
15 Kincardine and one in Port Elgin. After 2008 no other 5 kV cable has been identified for the
16 Town of Kincardine.

17
18 **Scope:** New conduit is bored into placed and new cables are pulled through the conduits. The
19 Pole Tran transformers are replaced with new pad mount transformers, with sufficient capacity
20 and accessibility.

21
22 **Capital Costs**

23 The capital costs for the Kincardine project is budgeted at \$445,500

24 The capital costs for the Port Elgin project is budgeted at \$504,700

25
26 **Start Dates**

27 Kincardine: June 16, 2008 to August 22, 2008

28 Port Elgin: May 1, 2008 to June 13, 2008.

29
30 **In-Service Date:** Staged as each section is completed.

2007 Actual

Project Description: 5kV Cable Replacement

In the past 5kV butyl rubber cable and "Pole Trans" transformers we used to service residential neighborhoods. The 5 kV cable is direct buried and is failing as it has surpassed its 30 year lifespan. The Pole Tran transformers are heavily loaded and extremely congested, posing worker safety issues.

Need: Emergency directional boring is expensive and, depending on the season, may not be practical. In the past, temporary pole lines have had to be built to restore power when conditions were not conducive to preferred repair techniques. Such temporary works are expensive and delay restoring power to customers.

In 2007 the 5kV Cable Replacement Program was two separate and distinct projects, one in Kincardine and one in Port Elgin.

Scope: New conduit is bored into placed and new cables are pulled through the conduits. The Pole Tran transformers are replaced with new pad mount transformers, with sufficient capacity and accessibility.

Capital Costs

The actual costs for the Kincardine project was \$344,866

The actual costs for the Port Elgin project was \$673,717

Start Dates

Kincardine: August 31, 2007 to Sept 28, 2007

Port Elgin: May 31, 2007 to Sept 7, 2007

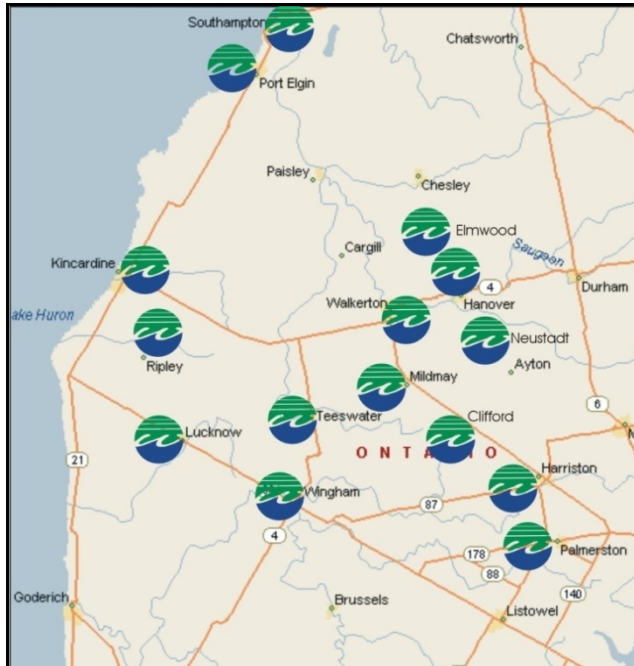
In-Service Date: Staged as each section was completed.

Project Description: New Operational Facility

Westario Power came into existence on November 1, 2000 through the merger of the municipally owned electric utilities belonging to:

- The Township of Huron-Kinloss
- The Municipality of Kincardine
- The Municipality of South Bruce
- The Town of Saugeen Shores
- The Town of Wingham
- The Municipality of Brockton
- The Town of Hanover
- The Town of Minto

In total, these municipalities owned 8 utilities (some had previously acquired other Local Distribution Companies (LDCs)) serving the 15 communities of Clifford, Elmwood, Hanover, Harriston, Kincardine, Lucknow, Mildmay, Neustadt, Palmerston, Port Elgin, Ripley, Southampton, Teeswater, Walkerton, and Wingham. This represents a span of approximately 60 kilometres east/west by 80 kilometres north/south.



Prior to the merger, local utility offices and/or service centres existed in 9 of these communities – namely Hanover, Harriston, Kincardine, Lucknow, Mildmay, Port Elgin, Teeswater, Walkerton, and Wingham.

The working group established by the shareholders to lead the merger process, recognized that operating and maintaining 8 offices/service centres not only created inefficiencies, but also operational challenges – particularly in light of the large geographical span and separation of the communities served.

None of the existing facilities was large enough to accommodate the combined staff, fleet and inventory. Nor did any of these sites have enough land to expand the facility to meet these needs.

Due to the large geographic area covered by Westario Power, consideration was also given to centralizing operations in a location that would contribute towards meeting the emergency response provisions of the OEB's Service Quality Indicators.

1
2 Considering all of these factors, it was decided not to transfer the ownership of the previous
3 office/service centres to Westario Power. The Company would lease the existing facilities and
4 transition over time to one facility. This facility could be purchased, leased or built depending on
5 the availability of a suitable property.

6
7 In 2005, after completing a space needs study, a search was conducted for available buildings
8 and vacant lands that would meet Westario Power's needs for a combined administration and
9 operations centre. The search was centred on Walkerton and the surrounding area as this area
10 is somewhat central to, and has good roadway access to, the communities being served. Two
11 existing buildings and several vacant lands were identified.

12
13 While negotiations were held with the identified building owners, suitable arrangements could
14 not be concluded. It was also determined that these properties, along with all but one of the
15 vacant sites, had very restrictive zoning in place that would not accommodate Westario Power's
16 intended use without applying for rezoning. Based upon information received from the
17 municipality and county, a rezoning application was expected to be a long process without any
18 assurance that the application would be approved.

19
20 The remaining site, located in the Walkerton Eastridge Industrial Park, was zoned appropriately
21 and priced attractively. Accordingly, the site was purchased in 2006.

22
23 Early in 2006, a tender call was issued for the new building:

- 24 • Four bids were received from seven invited firms.
- 25 • Bids ranged from \$2,733,430 to \$2,900,000
- 26 • The lowest price bid was selected for final negotiation.
- 27 • A final price of \$2,102,818 was agreed upon.
- 28 • In addition to the building contract price, an additional approximate \$400,000 was added to
29 establish a budget of \$2,500,000. This amount included:
 - 30 • Architect, project management, legal and design fees

- Works outside the scope of the building contract, such as security system and computer/telephone networking installation
- Energy saving initiatives
- Contingency allowance

Construction started in November 2006 and the building was occupied on June 26, 2007. A picture of the completed building is provided below.



Financial Factors

Previous Leases

The lease costs, plus property taxes, at the previous facilities are summarized below:

Location	Annual Lease Amount	Property Taxes	Total
Hanover	\$ 32,760	\$ 12,220	\$ 44,980
Kincardine	\$ 58,260	\$ 23,393	\$ 81,653
Harriston	\$ 8,532	In Lease	\$ 8,532
Port Elgin	\$ 29,496	In Lease	\$ 29,496
Wingham	\$ 18,300	In Lease	\$ 18,300
Lucknow	\$ 2,000	In Lease	\$ 2,000
Walkerton	\$ 3,860	In Lease	\$ 3,860
Mildmay	\$ 12,208	In Lease	\$ 12,208
Total	\$ 165,416	\$ 35,613	\$ 201,028

New Building Costs

The actual costs of the new building are as follows:

Land	\$ 135,000
Building & Fixtures	\$ 2,450,304
Total	\$ 2,585,304

Annual depreciation expense is \$49,006.

Operational Factors

Centralizing the administration and operational staff has a number of qualitative benefits which cannot directly be expressed in financial savings. These are described below.

Customer Service

One Call Centre, along with one Customer Information System (CIS), was established for all customers. Customers now have one access point for all inquiries including:

- Account inquires
- Underground Cable Locate requests
- New Service Installations
- Trouble Call Reporting

1 Service levels have been improved due to the larger combined number of specialized customer
2 service agents that can be supported by the combined volume of inquiries.

3 4 **Operations**

5 A combined facility has made scheduling and assigning work to line crews more efficient.
6 Larger crews can be configured where needed to accomplish capital and maintenance projects
7 in a shorter time. This reduces the impact on customers where planned power outages are
8 needed to replace or rebuild distribution plant, and makes such projects more cost effective.

9
10 Due to the large geographic territory over which Westario's service territories are dispersed,
11 adverse weather conditions, such as winter storms, rarely affect all communities. Having
12 centralized control over all field personnel allows crews to be dispatched to affected areas in
13 numbers larger than the former LDCs had in their employ. Customers, therefore, benefit from
14 shorter power outages caused by significant weather events.

15 16 **Inventory Control**

17 Centralizing the Company's material inventory has lead to better management and control of
18 inventory. Write-offs have been reduced from a high of 12% of inventory to 2%.

19 20 **Health & Safety**

21 One facility has reduced the number of required workplace inspections under the *Occupational*
22 *Health and Safety Act* to one per month. Under the *Act* each former location required its own
23 monthly inspection.

24
25 None of the previous facilities were large enough to hold health and safety training for all line
26 staff. The new building provides this room eliminating the need to rent off-site space.

27
28 One facility has also eliminated the need for multiple copies of the Material Safety Data Sheets
29 (MSDS) – one for each previous location. This reduces the costs to maintain the MSDS
30 documentation as well as the risk that the material is outdated.

Inter-office travel

With multiple locations, the cost and lost productive due to inter-office travel was considerable. Inter-office travel was necessary for such activities as project planning, safety meetings, management meetings, and employee workplace meetings.

Operating out of one site now permits this time to be spent in more productive efforts to the benefit of customers.

.

Staff Relations

Perhaps some of the most important benefits of a consolidated facility were those relating to improved internal communications and strengthened relationships amongst staff.

The distributed nature of the previous facilities made daily communications with staff challenging. The physical isolation of staff did not permit a sense of belonging to one company.

Corporate culture is more than the establishment of goals, objectives, policies and practices. Its success relies upon everyone within the organization having an understanding of these issues and the role the individual plays in their achievement. The daily interaction of staff from all areas of the business builds on the sense of belonging and, thereby, employee morale.

2006 EDR

The applicant has no capital variances in 2006 EDR year that meet the materiality threshold.

System Expansions

All projects planned are considered enhancement. The New Connections project is budgeted based on new customer connections for existing subdivision. WPI's contributed capital policy is as stated below:

- Distribution System Expansion (Green Field)
 - Developer will be charged a portion of the actual cost of servicing the project based on the OEB Economic Evaluation Methodology.
 - The revenue guarantee rebate, if any, will be prorated by connection load to calculate a rebate per customer for each of the customer classes served by the development.
 - The corresponding rebate per customer will be refunded to the developer annually based upon the services connected during the year.
- Infilling
 - A standard connection charge will be calculated for each customer class based upon the minimal requirements of the Distribution System Code.
 - Customers will be charged the costs associated with the installation of connection assets in excess of the basic connection.

Capitalization Policy

Applicability

This policy applies to the capitalization of assets for Westario Power Inc. ("The Company").

Policy Statement & Purpose

It is the policy of the company to maintain strong financial control over expenditures for capital assets by evaluating and approving capital requests for projects that enhance or improve the efficiency of the Company's assets.

Expenditures are capitalized to ensure there is an equitable allocation of costs to existing and future customers. Assets are expected to provide future economic benefits for more than one year. Any expenditure associated with the acquisition, construction, development or betterment of an asset should be capitalized and allocated over the useful life of the asset.

The policy describes the process used for determining if expenditures should be capitalized or expensed. A materiality amount is used and any expenditure below that threshold will be expensed to operations in the current year.

Guidelines

Tangible Assets

Property, plant and equipment are identified as tangible assets provided they are held for use in the production or supply of goods and services, are intended for a continuing use, and are not intended for sale in the ordinary course of business.

Intangible Assets

An intangible asset is an asset that lacks physical substance.

Goodwill

When an asset is acquired for a cost over and above the net amount of the acquired assets and assumed liability, the excess cost is considered goodwill.

Capital Assets

Capital Assets include tangible assets which include property, plant, and equipment provided they are held for use in the production or supply of goods and services. Intangible assets are also considered capital assets and are identified as assets that lack physical substance.

Betterment

A betterment is a cost which enhances the service potential of a capital asset and is therefore capitalized. This enhancement can result in an increase in physical output or service capacity, a decrease to operating costs, extension of the useful life of the asset, or improvement in the quality of the asset's output.

Repair

A repair is a cost incurred to maintain the service potential of a capital asset. Expenditures for repairs are expensed to the current operating period.

Materiality

All additions to capital assets and betterments will be capitalized subject to materiality limits as set out in this policy. At times the administrative costs of capitalizing an asset may outweigh the intended benefits. While the expenditure may meet the definition to qualify as a capital asset, a level is set, which if an expenditure falls below, it is not capitalized but charge to expense in the current period. This level is known as a materiality limit.

Materiality Limits

Identifiable Assets

Distribution Plant \$ 1,000

General Plant \$ 1,000

Grouped Assets

Distribution Plant \$ 1,000

General Plant \$ 1,000

Identifiable Assets

An identifiable capital asset that has a sufficiently high unit cost and is easily identifiable for the asset to be individually tracked and recorded.

Grouped Assets

For efficiency, capital assets may be grouped if, by their nature, it would be impractical to identify individual units. These grouped assets are managed as a pool for the purposes of amortization.

Capital Asset Records

Cost

Cost is the amount of consideration given up to acquire, construct, develop or better a capital asset. Capital assets will be recorded at the fully allocated cost.

Fully Allocated costs

Fully allocated costs include all expenditures necessary to put a capital asset in service including all overhead cost based on full absorption costing.

Amortization

Capital assets are generally amortized based on a method and life set by the OEB which is considered a suitable indicator of estimated useful life for the electrical distribution industry. Large and unique capital expenditures will be reviewed on an individual basis to determine the expected life and appropriate method of depreciation.

1 **Capital Spares**

2 Spare transformers and meters will be accounted for as capital assets since they form
3 an integral part of the reliability program for a distribution system. These spares are held
4 for the purpose of backing up transformers and meters in-service for a distribution
5 system. Transformers and meters received for the purpose of expanding the distribution
6 system will only be capitalized once they are put in-service and will remain in inventory
7 until that time.

8
9 **Extraordinary Items**

10 Extraordinary items will be identified separately provided they exceed the materiality
11 threshold established by the OEB. Recovery of extraordinary items through rates as a
12 “Z” Factor expense will follow OEB guidelines.

13
14 **Policy Compliance**

15 All current practices will comply with OEB Accounting Procedures Handbook and the CICA
16 Handbook. Employees must report incidents of non-compliance relating to this policy in a timely
17 manner to the Chief Financial Officer. Non-compliance of a serious nature will be immediately
18 reported to the President/CEO. Determination of non-compliance issues of a serious nature will
19 be the responsibility of the Chief Financial Officer.

1

Summary of 2008 Working Capital Allowance

Account Grouping	2009 Projected Acct Balance	Working Capital Allowance
3350-Power Supply Expenses Total	33,551,217	5,032,683
3500-Distribution Expenses - Operation Total	480,400	72,060
3550-Distribution Expenses - Maintenance Total	1,164,675	174,701
3650-Billing and Collecting Total	1,242,900	186,435
3700-Community Relations Total	35,500	5,325
3800-Administrative and General Expenses Total	1,888,350	283,252
3950-Taxes Other Than Income Taxes Total	56,600	8,490
Grand Total	38,419,642	5,762,946

2

3

1 **Working Capital Allowance calculations by accounts**

2

3 The following attachment is the Working Capital Allowance by Account.

4

Working Capital Allowance by Account

Working Capital Allowance Factor:			15.0%
Account Grouping	Account Description	2009 Projected Acct Balance	Working Capital Allowance
3350-Power Supply Expenses	4705-Power Purchased	25,515,756	3,827,363
	4708-Charges-WMS	2,902,710	435,406
	4714-Charges-NW	1,994,897	299,235
	4716-Charges-CN	2,404,377	360,657
	4750-Charges-LV	733,477	110,022
3500-Distribution Expenses - Operation	5040-Underground Distribution Lines and Feeders - Operation Labour	469,400	70,410
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	10,000	1,500
	5075-Customer Premises - Materials and Expenses	1,000	150
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	16,775	2,516
	5114-Maintenance of Distribution Station Equipment	246,800	37,020
	5120-Maintenance of Poles, Towers and Fixtures	77,400	11,610
	5125-Maintenance of Overhead Conductors and Devices	131,200	19,680
	5130-Maintenance of Overhead Services	106,600	15,990
	5135-Overhead Distribution Lines and Feeders - Right of Way	270,900	40,635
	5155-Maintenance of Underground Services	112,000	16,800
	5160-Maintenance of Line Transformers	108,000	16,200

Working Capital Allowance by Account

		Working Capital Allowance Factor:	15.0%
Account Grouping	Account Description	2009 Projected Acct Balance	Working Capital Allowance
	5175-Maintenance of Meters	95,000	14,250
3650-Billing and Collecting	5305-Supervision	16,775	2,516
	5310-Meter Reading Expense	272,000	40,800
	5315-Customer Billing	387,725	58,159
	5320-Collecting	416,400	62,460
	5335-Bad Debt Expense	150,000	22,500
3700-Community Relations	5410-Community Relations - Sundry	20,500	3,075
	5420-Community Safety Program	15,000	2,250
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	130,000	19,500
	5610-Management Salaries and Expenses	689,400	103,410
	5615-General Administrative Salaries and Expenses	143,300	21,495
	5620-Office Supplies and Expenses	368,650	55,298
	5630-Outside Services Employed	178,500	26,775
	5635-Property Insurance	101,125	15,169
	5640-Injuries and Damages	2,500	375
	5655-Regulatory Expenses	140,000	21,000
	5660-General Advertising Expenses	3,000	450

Working Capital Allowance by Account

Working Capital Allowance Factor:			15.0%
Account Grouping	Account Description	2009 Projected Acct Balance	Working Capital Allowance
	5665-Miscellaneous General Expenses	33,550	5,033
	5675-Maintenance of General Plant	98,325	14,749
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	56,600	8,490
TOTAL		38,419,642	5,762,946

Overview of Distribution Revenue

This exhibit provides the details on the Applicant's Distribution Revenues for Historical, Historical Board Approved, Bridge year and Test years. This exhibit also provides a detailed variance analysis by rate class of the Distribution Revenue components.

Distribution revenues have been calculated using the most recently approved rates. Specifically delivery rates approved in EB-2007-0865 Rate Order, dated April 17, 2008. A summary of normalized Distribution Revenues is presented in Exhibit 3, Tab 1, Schedule 2. Distribution revenues do not include a smart meter adder. Distribution revenues do however include amounts for the Transformer Allowance Hydro One Networks Inc. ("Hydro One") Low Voltage charges.

Throughput Revenue

Information related to the utility's throughput revenue include details such as weather normalized forecasting methodology, normalized volume, and customer count forecast tables.

Other Revenue

Other revenues include revenues such as Late Payment Charges, Miscellaneous Service Revenues and Retail Services Revenues. A summary of these Distribution Revenues is presented in Exhibit 3, Tab 3, Schedule 1. Variance analysis of these Distribution Revenues is included in Exhibit 3, Tab 3, Schedule 2.

Revenue Sharing

WPI does not participate in revenue sharing.

Summary of Distribution Revenue Table

Operation Revenue Summary is presented in the following tables:

Operating Revenue Summary

Distribution Revenue	2009 Projection *	2008 Projection *	Var \$	2008 Projection *	2007 Normalized*	Var \$
<i>* Pro-forma, as if EDR rates became effective January 1st</i>						
Residential	6,088,311	4,996,976	1,091,335	4,996,976	4,991,487	5,489
General Service Less Than 50 kW	1,431,632	1,156,315	275,317	1,156,315	1,156,463	(148)
General Service 50 to 4,999 kW	2,162,305	1,714,972	447,333	1,714,972	1,712,804	2,168
Unmetered Scattered Load	33,116	26,368	6,748	26,368	26,270	97
Sentinel Lighting	626	216	410	216	217	(1)
Street Lighting	352,489	189,473	163,017	189,473	189,740	(267)
Gross Revenue (before Transformer Allowances)	10,068,480	8,084,320	1,984,160	8,084,320	8,076,982	7,338
Transformer Allowances	(69,720)	(69,720)		(69,720)	(41,031)	(28,689)
Total Revenue	9,998,760	8,014,600	1,984,160	8,014,600	8,035,951	(21,351)
Less: Low voltage charges embedded in distribution rates	(733,477)	(253,892)	(479,585)	(253,892)	(253,457)	(435)
DISTRIBUTION REVENUE	9,265,283	7,760,708	1,504,575	7,760,708	7,782,494	(21,786)

Operating Revenue Summary

Distribution Revenue	2007 Normalized*	2006 Normalized*	Var \$	2006 Normalized*	2006 EDR Approved	Var \$
<i>* Pro-forma, as if EDR rates became effective January 1st</i>						
Residential	4,991,487	4,943,204	48,283	4,943,204	4,973,264	(30,059)
General Service Less Than 50 kW	1,156,463	1,137,563	18,901	1,137,563	1,137,859	(296)
General Service 50 to 4,999 kW	1,712,804	1,693,267	19,538	1,693,267	1,703,461	(10,194)
Unmetered Scattered Load	26,270	26,947	(677)	26,947	27,955	(1,007)
Sentinel Lighting	217	229	(12)	229	530	(301)
Street Lighting	189,740	192,303	(2,563)	192,303	192,876	(573)
Gross Revenue (before Transformer Allowances)	8,076,982	7,993,513	83,469	7,993,513	8,035,943	(42,431)
Transformer Allowances	(41,031)	(40,271)	(760)	(40,271)	(72,097)	31,826
Total Revenue	8,035,951	7,953,242	82,709	7,953,242	7,963,846	(10,605)
Less: Low voltage charges embedded in distribution rates	(253,457)	(252,862)	(594)	(252,862)	(257,598)	4,736
DISTRIBUTION REVENUE	7,782,494	7,700,379	82,115	7,700,379	7,706,248	(5,869)

Calculations of Distribution Revenue Table

Calculations of distribution revenues for historic, 2008 bridge year and 2009 test year are as follows:

Distribution Revenue Calculations

2006 EDR Approved	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge ¹	Distribution Revenue
Residential	17,881	11,384		\$0.0133		\$10.56	4,973,264
General Service Less Than 50 kW	2,314	30,476		\$0.0085		\$19.39	1,137,859
General Service 50 to 4,999 kW	246	621,089	1,838.350		\$2.2070	\$238.95	1,703,461
Unmetered Scattered Load	70	7,689		\$0.0451		\$4.38	27,955
Sentinel Lighting	16	827	2.438		\$6.9328	\$1.35	530
Street Lighting	6,030	800	2.252		\$1.9477	\$2.30	192,876
Gross Revenue (before Transformer Allowances)							8,035,943
Transformer Allowances (enter total credits as negative amount)							(72,097)
Total Revenue							7,963,846
Less: Low voltage charges embedded in distribution rates							(257,598)
DISTRIBUTION REVENUE							7,706,248

¹ Excluding Smart Meter Rate Adder

2006 Normalized Pro-forma *	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge ¹	Distribution Revenue
<i>* As if EDR rates became effective January 1st</i>							
Residential	18,150	10,950		\$0.0133		\$10.56	4,943,204
General Service Less Than 50 kW	2,338	29,867		\$0.0085		\$19.39	1,137,563
General Service 50 to 4,999 kW	250	654,852	1,769.672		\$2.2070	\$238.95	1,693,267
Unmetered Scattered Load	70	7,370		\$0.0451		\$4.38	26,947
Sentinel Lighting	6	2,317	3.167		\$6.9328	\$1.35	229
Street Lighting	6,041	763	2.173		\$1.9477	\$2.30	192,303
Gross Revenue (before Transformer Allowances)							7,993,513
Transformer Allowances (enter total credits as negative amount)							(40,271)
Total Revenue							7,953,242
Less: Low voltage charges embedded in distribution rates							(252,862)
DISTRIBUTION REVENUE							7,700,379

¹ Excluding Smart Meter Rate Adder

Distribution Revenue Calculations

2007 Normalized Pro-forma *	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge ¹	Distribution Revenue
<i>* As if EDR rates became effective January 1st</i>							
Residential	18,390	10,709		\$0.0134		\$10.66	4,991,487
General Service Less Than 50 kW	2,354	29,832		\$0.0086		\$19.56	1,156,463
General Service 50 to 4,999 kW	248	160,616,501	1,802		\$2.2269	\$241.10	1,712,804
Unmetered Scattered Load	68	7,325		\$0.0455		\$4.42	26,270
Sentinel Lighting	6	2,805	3		\$6.9982	\$1.36	217
Street Lighting	6,041	686	2		\$1.9652	\$2.32	189,740
Gross Revenue (before Transformer Allowances)							8,076,982
Transformer Allowances (enter total credits as negative amount)							(41,031)
Total Revenue							8,035,951
Less: Low voltage charges embedded in distribution rates							(253,457)
DISTRIBUTION REVENUE							7,782,494

¹ Excluding Smart Meter Rate Adder

2008 Projection *	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge ¹	Distribution Revenue
<i>* As if EDR rates became effective January 1st</i>							
Residential	18,631	10,593		\$0.0133		\$10.61	4,996,976
General Service Less Than 50 kW	2,360	29,819		\$0.0086		\$19.46	1,156,315
General Service 50 to 4,999 kW	251	641,258	1,784		\$2.2158	\$239.89	1,714,972
Unmetered Scattered Load	69	7,270		\$0.0453		\$4.40	26,368
Sentinel Lighting	6	2,773	3		\$6.9632	\$1.35	216
Street Lighting	6,059	682	2		\$1.9554	\$2.31	189,473
Gross Revenue (before Transformer Allowances)							8,084,320
Transformer Allowances							(69,720)
Total Revenue							8,014,600
Less: Low voltage charges embedded in distribution rates							(253,892)
DISTRIBUTION REVENUE							7,760,708

¹ Excluding Smart Meter Rate Adder

Distribution Revenue Calculations

2009 Projection	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge ¹	Distribution Revenue
<i>* As if EDR rates became effective January 1st</i>							
Residential	18,875	10,471		\$0.0161		\$12.84	6,088,311
General Service Less Than 50 kW	2,365	29,800		\$0.0106		\$24.05	1,431,632
General Service 50 to 4,999 kW	252	639,653	1,780		\$3.2034	\$239.89	2,162,305
Unmetered Scattered Load	69	7,270		\$0.0475		\$11.19	33,116
Sentinel Lighting	6	2,773	3		\$20.2204	\$3.92	626
Street Lighting	6,077	682	2		\$3.6270	\$4.28	352,489
Gross Revenue (before Transformer Allowances)							10,068,480
Transformer Allowances							(69,720)
Total Revenue							9,998,760
Less: Low voltage charges embedded in distribution rates							(733,477)
DISTRIBUTION REVENUE							9,265,283

¹ Excluding Smart Meter Rate Adder

Variance Analysis on Distribution Revenue

* Pro-forma as if EDR Rates became effective January 1st	2006 Actual Normalized	2006 EDR Approved	Var \$	Var %
Residential	4,943,204	4,973,264	(30,059)	-0.6%
General Service Less Than 50 kW	1,137,563	1,137,859	(296)	0.0%
General Service 50 to 4,999 kW	1,693,267	1,703,461	(10,194)	-0.6%
Unmetered Scattered Load	26,947	27,955	(1,007)	-3.6%
Sentinel Lighting	229	530	(301)	-56.8%
Street Lighting	192,303	192,876	(573)	-0.3%
Gross Revenue (before Transformer Allowances)	7,993,513	8,035,943	(42,431)	-0.5%
Transformer Allowances	(40,271)	(72,097)	31,826	-44.1%
Total Revenue	7,953,242	7,963,846	(10,605)	-0.1%
Less: Low voltage charges embedded in distribution rates	(252,862)	(257,598)	4,736	-1.8%
DISTRIBUTION REVENUE	7,700,379	7,706,248	(5,869)	-0.1%

There is very little difference (-0.5%) between 2006 Normalized revenues and 2006 EDR Approved revenues. It should be noted that the 2006 EDR Approved numbers are an average of 2002, 2003 and 2004 consumption and are not adjusted for weather, making the variance analysis somewhat skewed. The largest dollar amount decrease is in the residential rate category, which saw an overall decrease of 0.6%. This decrease can be attributed to the fact that although the number of customers increased by 269; the average consumption per customer per year decreased by 435 kWh (a decrease of 3.8%) from the 2006 EDR Approved to 2006 Actual. The difference in the Transformer Allowance can be attributed to the fact that a customer eligible for the transformer allowance inadvertently did not receive their eligible allowance. The error was discovered in 2008, and has since been rectified.

1

* Pro-forma as if EDR Rates became effective January 1st	2007 Actual Normalized	2006 Actual Normalized	Var \$	Var %
Residential	4,991,487	4,943,204	48,283	1.0%
General Service Less Than 50 kW	1,156,463	1,137,563	18,901	1.7%
General Service 50 to 4,999 kW	1,712,804	1,693,267	19,538	1.2%
Unmetered Scattered Load	26,270	26,947	(677)	-2.5%
Sentinel Lighting	217	229	(12)	-5.3%
Street Lighting	189,740	192,303	(2,563)	-1.3%
Gross Revenue (before Transformer Allowances)	8,076,982	7,993,513	83,469	1.0%
Transformer Allowances	(41,031)	(40,271)	(760)	1.9%
Total Revenue	8,035,951	7,953,242	82,709	1.0%
Less: Low voltage charges embedded in distribution rates	(253,457)	(252,862)	(594)	0.2%
DISTRIBUTION REVENUE	7,782,494	7,700,379	82,115	1.1%

2

3 Between 2006 and 2007, there were increases in the Residential, General Service less than
 4 50kW and General Service greater than 50kW categories. This is largely due to the fact that
 5 between 2006 and 2007 the distribution rates increased in each rate category by approximately
 6 1% and an increase in customers in the Residential and General Service less than 50 kW
 7 categories. Decreases in Unmetered Scattered Load and Street Lighting were largely due to
 8 no customer growth, and decreased consumption. Overall increase of 1.1% is consistent with
 9 the upward trend of distribution rates.

10

* Pro-forma as if EDR Rates became effective January 1st	2008 Bridge	2007 Actual Normalized	Var \$	Var %
Residential	4,996,976	4,991,487	5,489	0.1%
General Service Less Than 50 kW	1,156,315	1,156,463	(148)	0.0%
General Service 50 to 4,999 kW	1,714,972	1,712,804	2,168	0.1%
Unmetered Scattered Load	26,368	26,270	97	0.4%
Sentinel Lighting	216	217	(1)	-0.6%
Street Lighting	189,473	189,740	(267)	-0.1%
Gross Revenue (before Transformer Allowances)	8,084,320	8,076,982	7,338	0.1%
Transformer Allowances	(69,720)	(41,031)	(28,689)	69.9%
Total Revenue	8,014,600	8,035,951	(21,351)	-0.3%
Less: Low voltage charges embedded in distribution rates	(253,892)	(253,457)	(435)	0.2%
DISTRIBUTION REVENUE	7,760,708	7,782,494	(21,786)	-0.3%

11

12 Between 2007 Actual Normalized and 2008 Bridge Year, there is minimal effect on distribution
 13 revenues. Although numbers of customers are increasing in each of the Residential, General

Service less than 50 kW and General Service greater than 50kW classes; each of the categories experienced decreased consumption as evidenced in Exhibit 3, Tab 2, Schedule 5. Overall, distribution rates in all categories decreased by approximately 0.5% as Evidenced in Exhibit 3, Tab 1, Schedule 3. The increase in the transformer allowance has been adjusted to properly reflect all customers eligible for the allowance. Overall decrease of 0.3% is consistent with downward trend of distribution rates.

* Pro-forma as if EDR Rates became effective January 1st	2009 Test (at current rates)	2008 Bridge	Var \$	Var %
Residential	5,031,902	4,996,976	38,926	0.7%
General Service Less Than 50 kW	1,158,373	1,156,315	2,058	0.2%
General Service 50 to 4,999 kW	1,719,309	1,714,972	4,337	0.3%
Unmetered Scattered Load	26,368	26,368	0	0.0%
Sentinel Lighting	216	216	0	0.0%
Street Lighting	190,036	189,473	563	0.3%
Gross Revenue (before Transformer Allowances)	8,126,204	8,084,320	41,884	0.5%
Transformer Allowances	(69,720)	(69,720)	0	0.0%
Total Revenue	8,056,484	8,014,600	1,869,824	23.3%
Less: Low voltage charges embedded in distribution rates	(253,892)	(253,892)	0	0.0%
DISTRIBUTION REVENUE	7,802,592	7,760,708	41,884	0.5%

Between 2008 Bridge and 2009 Test there is very little change in overall consumption by rate category as evidenced in Exhibit 3, Tab 2, Schedule 5. The slight increases above are due to forecast consumption in each of the rate categories.

Weather Normalization Forecasting Methodology

WPI engaged the services of Elenchus Research Associates (“ERA”) to complete a Weather Normalized Distribution System Load Forecast. A copy of the report dated June 23, 2008 is provided as an attachment to this section.

The forecast is based on monthly wholesale purchases for the Distribution System from January 2003 to December 2007. The volumes have not been adjusted for Distribution System Losses; that is, they represent bulk electricity system deliveries to the Distribution Utility. Forecast retail volumes for each class are corrected for distribution system losses.

Short-term variation in electricity consumption is heavily influenced by three main factors – weather (e.g. heating and cooling), which is by far the most dominant effect for most systems; economic factors (increases or decreases in economic activity leads to changes in employment, industrial and commercial activity, building and population change); and timing factors (non-holiday weekdays when businesses are typically operating). All of these factors were considered in developing WPI’s weather corrected load forecast and variables to account for the effects have been incorporated where appropriate.

While it may be desirable to isolate demand determinants related to individual rate classes, such as residential, commercial, and industrial (since demand determinants and weather sensitivity may be different for each of these classes), data limitations precluded WPI the ability to do so.

Weather normalization involves removing the year-to-year variations in consumption caused by variations due to weather. This is achieved by estimating a statistical relationship between observed monthly weather and observed monthly consumption. Once the statistical relationship between monthly weather and consumption is obtained, year-to-year variance in weather conditions is controlled for by defining a “weather normal” month. As it is not possible to accurately forecast weather for months or years in advance, future weather expectations have

1 been based on what has happened in the past. WPI's has adopted a 10-year average from
2 1998 to 2007 as the appropriate definition of weather normal.

3
4 Historical observations are weather normalized by replacing actual observed weather with
5 normal weather in the statistical relationship to obtain what consumption would have been
6 consumed if weather had been "normal". Future consumption is forecast based on normal
7 weather and forecast economic and timing variables.

8
9 As required by the OEB Filing Requirements for Transmission and Distribution Applications,
10 WPI is providing normalized historical and forecast (Bridge Year and Test Year) throughput
11 data. Weather normalization (where required) is based on normalized average use per
12 customer ("NAC") calculated from the weather-normalized throughput of the utility from 2007.

13
14 The following attachment shows the Load Forecast Report
15

**Medium Term Weather Normalized Distribution
System Load Forecast
2008 to 2009**

**Prepared for
Westario Power Inc.**

June 23, 2008

1 INTRODUCTION

This document outlines the results and methodology used to derive the weather normal load forecast prepared for use in the Westario Power rebasing rate application for 2009 rates. A weather normal load forecast was developed for the bridge year (2008) and test year (2009) and weather normalized historical consumption was also derived.

The forecast for Westario Power is based on monthly wholesale purchases for the Distribution System from January 2003 to December 2007.¹ These volumes have not been adjusted for Distribution System Losses; that is, they represent bulk electricity system deliveries to the Distribution Utility. Forecast retail volumes for each class are corrected for distribution system losses, as described in more detail below.

Short-term variation in electricity consumption is heavily influenced by three main factors – weather (e.g. heating and cooling), which is by far the most dominant effect for most systems; economic factors (increases or decreases in economic activity leads to changes in employment, industrial and commercial activity, building and population change); and timing factors (non-holiday weekdays when businesses are typically operating). We have examined all of these factors in considering Westario's load and correcting for weather anomalies and have incorporated variables to account for these effects where appropriate.

While it may be desirable to isolate demand determinants related to individual rate classes, such as residential, commercial, and industrial (since demand determinants and weather sensitivity may be different for each of these classes), data limitations precluded the ability to do this for Westario.

¹ Due to significant restructuring and billing system changes, accurate class specific data prior to January 2004 is not available. 2003 data are presented but are available on an annual basis only and are generated from a different accounting system.

2 ENERGY FORECAST USING WHOLESALE KWH DELIVERIES

The following table outlines monthly wholesale deliveries from January 2003 to December 2007.

Table 1: Monthly Actual Energy (kWh), Westario Power

	2003	2004	2005	2006	2007
January	49,333,251	50,305,894	49,997,725	44,937,035	47,095,766
February	45,154,841	43,870,843	40,417,874	42,691,244	46,263,514
March	43,176,868	42,606,311	44,241,746	43,508,742	42,930,126
April	35,816,740	36,626,322	34,643,522	33,743,146	36,963,796
May	32,577,216	32,216,445	32,269,593	32,729,520	32,508,070
June	30,699,843	30,459,512	34,391,247	31,566,330	32,770,637
July	32,141,122	31,672,398	34,544,463	34,917,039	32,951,891
August	31,805,813	32,146,211	34,610,070	33,277,985	34,566,788
September	30,026,255	31,723,222	31,186,828	30,847,692	31,514,547
October	34,902,541	33,792,681	33,922,767	36,246,657	33,950,544
November	36,491,817	38,371,359	38,602,483	38,532,456	40,357,585
December	44,111,192	47,463,987	47,350,258	43,712,299	47,630,762
Annual	446,237,501	451,255,185	456,178,576	446,710,143	459,504,027
% change		1.1%	1.1%	-2.1%	2.9%

In order to determine the relationship between observed weather and energy consumption, monthly weather observations describing the extent of heating or cooling required within the month are necessary. Environment Canada publishes monthly observations on heating degree days (HDD) and cooling degree days (CDD) for selected weather stations across Canada. Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18°C. Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18°C. For Westario, we have used monthly HDD and CDD as reported at Wiarton Airport (YVV) in Bruce County. Westario's service area includes communities located in Bruce, Grey, Huron and Wellington.

In order to measure the change in economic activity, a data series must be chosen which represents, as much as possible, regional economic activity. We have used the monthly full-time employment levels for the Stratford-Bruce Peninsula economic region, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM series v2054780).

Finally, we have used the number of non-holiday weekdays in the month to account for peak day consumption. We have included New Year's Day, Good Friday, Easter Monday, Victoria Day, Canada Day, August Civic Holiday (Simcoe Day), Labour Day, Thanksgiving Day, Christmas and Boxing Day. From 2008, we have included the Ontario Family Day holiday in February, but we have not included Remembrance Day in November. The historical data for monthly employment and peak days are displayed in *table 2* below.

Table 2
Monthly Peak Days

	2003	2004	2005	2006	2007
January	21	21	20	21	22
February	20	20	20	20	20
March	21	23	21	23	22
April	20	20	21	18	19
May	21	20	21	22	22
June	21	22	22	22	21
July	22	21	20	20	22
August	20	21	22	22	22
September	21	21	21	20	19
October	22	20	20	21	22
November	20	22	22	22	22
December	21	21	20	19	19
Full-Time Employment ('000s): Stratford- Bruce					
January	112.6	116.1	128.3	121.4	124.5
February	111.2	118.2	124.9	118.9	122.6
March	109	119.5	119.4	118.3	119.7
April	108.3	122.5	116.3	121.2	119.5
May	109.5	126.4	115.1	124.1	121.7
June	114.2	130.3	118.7	124.2	126.4
July	121.4	135.1	123.8	126.9	129.3
August	124.1	136.7	129.1	129.3	129.2
September	123.1	138.1	128.7	131.9	127.6
October	118.6	138.5	127.1	131.3	127.6
November	116.7	136.2	124.6	129.2	125.9
December	116.6	134.1	124.5	127.9	124.2
Ann % chg	-0.1%	12.0%	-4.6%	1.6%	-0.4%

Using this data, the following linear regression equation describing the relationship between monthly actual energy and the explanatory variables was estimated:

Table 3

OLS estimates using the 60 observations 2003:01-2007:12

Dependent variable: WholesalekWh

Unadjusted $R^2 = 0.961573$

Adjusted $R^2 = 0.958778$

F-statistic (4, 55) = 344.07 (p-value < 0.00001)

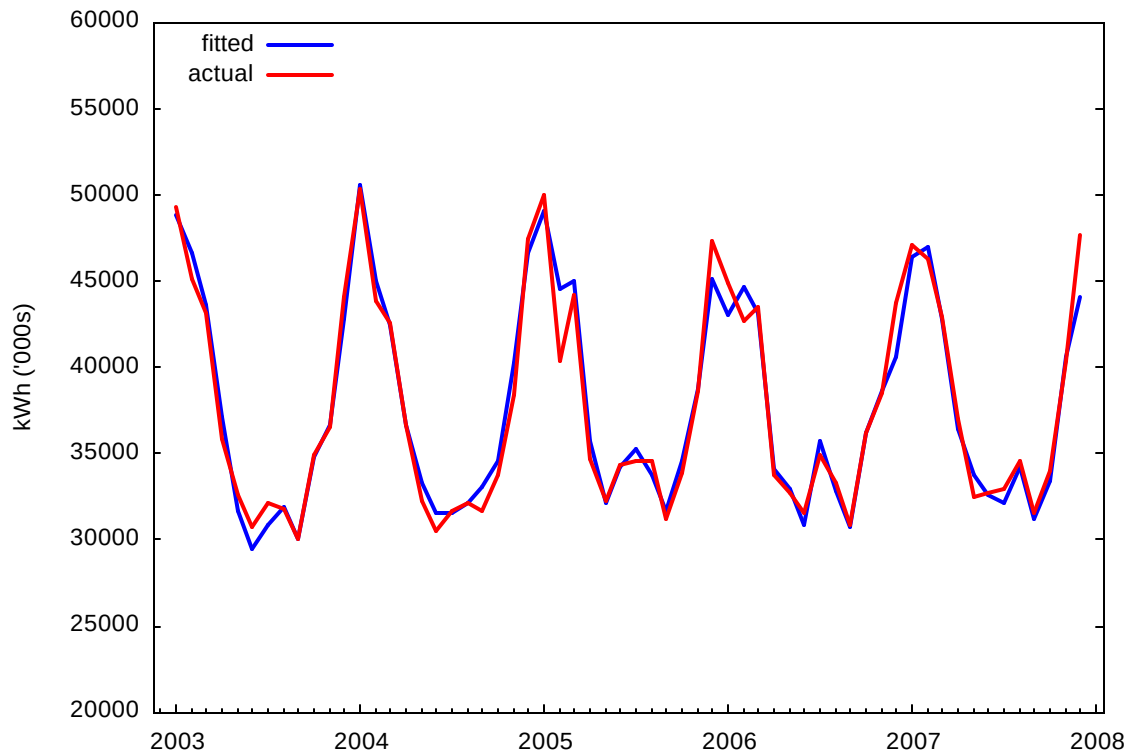
Durbin-Watson statistic = 1.79525

Variable Name	Estimated Coeff.	T-Ratio	P-Value
const	3,359,180.00	0.7389	0.46312
HDD	28,600.80	32.1617	<0.00001
CDD	108,720.00	10.7315	<0.00001
Peak days	462,257	3.0485	0.00353
FT Employ (Stratford-Bruce)	105,437.00	4.308	0.00007

Fitted vs. actual observations are plotted in the chart below:

Chart 1

Westario Power - Actual and Fitted Wholesale kWh



As can be seen from the above regression results, the effects of weather, the number of monthly peak days and monthly full-time employment have a statistically significant impact on monthly wholesale kWh for Westario. The equation shows significant explanatory power with an adjusted R^2 of 0.959. As can be seen in Table 4 below, when annual estimates are compared to actual values, the mean absolute percentage error (MAPE) for annual estimates for the period is less than 1% with the largest absolute error on an annual estimate at 1.38%.

Table 4 – Westario Actual vs Predicted			
<i>Year</i>	<i>Actual wholesale kWh</i>	<i>Predicted kWh</i>	<i>Error</i>
2003	446,237,501	444,487,913	-0.39%
2004	451,255,185	457,496,257	1.38%
2005	456,178,576	460,007,743	0.84%
2006	446,710,143	443,343,735	-0.75%
2007	459,504,027	454,548,995	-1.08%
Mean Absolute Percentage Error			0.89%

2.1 WEATHER NORMALIZATION AND FORECASTED KWH

It is not possible to accurately forecast weather for months or years in advance. Therefore, one can only base future weather expectations on what has happened in the past. Individual years may experience unusual spells of weather (unusually cold winter, unusually warm summer, etc.). However, over time, these unusual spells “average” out. While there may be trends over several years (e.g., warmer winters for example), using several years of data rather than one particular year filters out the extremes of any particular year. For Westario, the 10 year average from 1998 to 2007 has been adopted as the appropriate definition of weather normal. Other definitions also exist. Environment Canada publishes 30 year “Climate Normal” data based on observations from 1971 to 2000. The OEB has considered yet others (for example, a five-year rolling average used to predict heating degree days for bridge year and test year in the case of Natural Resource Gas Limited (RP-2004-0167)). Our view is that a ten-year average based on the most recent ten calendar years available is a reasonable compromise that likely reflects the “average” weather experienced in recent years. Others have also adopted this definition (for example, Toronto Hydro Electric System Limited in EB-2005-0421 and EB-2007-0680).

Presented below is a table outlining the 10-year and 30-year average monthly HDD and CDD for Wiarton Airport.

Table 5 – 30-yr and 10-yr HDD and CDD, Wiarton Airport (YVV)

	1971-2000 30-yr normal		1998-2007 10-yr normal	
	HDD	CDD	HDD	CDD
Jan	768.7	0.0	728.1	0.0
Feb	704.2	0.0	661.0	0.0
Mar	628.2	0.0	593.3	0.1
Apr	399.4	0.9	377.8	0.5
May	226.1	4.3	203.0	5.6
Jun	93.4	19.9	74.4	34.5
Jul	30.6	48.4	24.7	60.1
Aug	38.9	41.3	28.6	48.7
Sep	132.3	12.5	97.2	23.2
Oct	298.2	0.8	277.7	3.0
Nov	460.9	0.0	425.1	0.0
Dec	661.2	0.0	625.5	0.0
Annual	4,442.1	128.1	4,116.3	175.6

Forecasts for Ontario's employment outlook for 2008 and 2009 are available from four Canadian Chartered Banks at time of writing. Their forecasts are summarized below.

Table 6 - Employment Forecast – Ontario
(figures in annual percentage change)

	BMO (Winter 2008)	RBC (April 2008)	Scotia (May 30, 2008)	TD (April 16, 2008)	avg
2008	0.7	0.9	1.2	1.0	0.9
2009	0.7	1.0	0.8	0.4	0.7

Incorporating the forecast economic variables and 10-yr weather normal heating and cooling degree days, the following weather corrected consumption and forecast values are calculated:

Table 7 - Weather Corrected Wholesale kWh, Westario Power				
Year	Actual wholesale kWh	%chg	10-yr (1998-2007) Weather Normal	%chg
2003	446,237,501		438,755,532	
2004	451,255,185	1.1%	457,224,763	4.2%
2005	456,178,576	1.1%	448,793,134	-1.8%
2006	446,710,143	-2.1%	451,334,166	0.6%
2007	459,504,027	2.9%	451,583,883	0.1%
2008F			452,537,807	0.2%
2009F			453,203,301	0.1%

3 CLASS SPECIFIC CONSUMPTION FORECASTS

The following table (Table 8) presents class specific weather normal historic and forecast values for those classes that have weather sensitive load. Historic class specific kWh consumption is allocated based on each class' share in wholesale kWh, exclusive of distribution losses. Forecast class values are allocated based on the class share in 2007.

Table 8 - Weather Corrected Class Specific Consumption, Westario Power			
			10-yr (1998-2007)
Year	Actual residential kWh	Share%	Weather Normal
2003 ²	203,822,662		
2004	197,888,859	43.9%	200,506,697
2005	195,802,935	42.9%	192,632,923
2006	196,703,448	44.0%	198,739,582
2007	200,397,263	43.6%	196,943,158
2008F			197,359,181
2009F			197,649,413
Year	Actual GS<50 kWh	Share%	Weather Normal
2003 ²	75,281,676		
2004	70,856,084	15.7%	71,793,427
2005	69,391,252	15.2%	68,267,821
2006	69,114,782	15.5%	69,830,209
2007	71,456,354	15.6%	70,224,712
2008F			70,373,054
2009F			70,476,543
Year	Actual GS>50 kWh	Share%	Weather Normal
2003 ²	156,796,006		
2004	146,754,038	32.5%	148,695,422
2005	130,110,245	28.5%	128,003,786
2006	162,035,803	36.3%	163,713,081
2007	163,433,488	35.6%	160,616,501
2008F			160,955,787
2009F			161,192,485

Actual, normalized and forecast kW for the weather sensitive GS>50 class are summarized in Table 9 below. Historical normalized values are calculated based on the

² 2003 data are from a different accounting system and are presented for illustrative purposes only.

annual ratio of class kW to class kWh. Forecast kW is based on the class kW to class kWh ratio in 2007.

Table 9 – GS>50 Class kW (Actual, Normalized, and Forecast)

Year	Actual kW	% change	Class kW/kWh ratio	Normalized kW	% change
2003 ²	464,758				
2004	451,969		0.003079774	457,948	
2005	449,395	-0.6%	0.003453953	442,119	-3.5%
2006	437,885	-2.6%	0.0027024	442,418	0.1%
2007	454,779	3.9%	0.002782656	446,940	1.0%
2008F				447,885	0.2%
2009F				448,543	0.1%

The table below (Table 10) presents actual and forecast kWh and kW (where applicable) for the non-weather sensitive classes of street lighting, sentinel lighting and unmetered scattered load (USL). Street lighting kWh consumption and kW demand is forecast to growth at an equivalent rate to distribution system wholesale consumption (0.3 per cent in each of 2008 and 2009). No additional sentinel lights are expected to be added. Therefore, sentinel light energy and demand is assumed to continue at 2007 levels. A similar assumption is made for the USL class.

Table 10 below summarizes the lighting and USL consumption forecast.

Table 10

Lighting & USL Historic and Trend Forecast Consumption								
Year	<i>Street lighting</i>				<i>Sentinel Lighting</i>			
	kWh	%	kW	%	kWh	%	kW	%
2003 ²	4,873,517		13,573		12,638		38	
2004	4,104,812		9,943		10,741		19	
2005	5,927,078	44.4%	16,152	62.5%	7,150	-33.4%	20	3.7%
2006	4,644,694	-21.6%	13,130	-18.7%	14,130	97.6%	20	0.0%
2007	4,119,804	-11.3%	10,971	-16.4%	16,635	17.7%	17	-15.0%
2008F	4,132,164	0.3%	11,004	0.3%	16,635	0.0%	17	0.0%
2009F	4,144,560	0.3%	11,037	0.3%	16,635	0.0%	17	0.0%

Unmetered Scattered Load (USL)		
Year	kWh	%
2003 ²	558,939	
2004	527,951	
2005	587,965	11.4%
2006	527,907	-10.2%
2007	501,647	-5.0%
2008F	501,647	0.0%
2009F	501,647	0.0%

Table 11 below presents the results for class specific historic actual and historic normalized (2007) kWh and kW (where applicable), and normalized forecast values for bridge year (2008) and test year (2009).

Table 11 – Load Forecast (Historical, Bridge and Test Years).

	2007 Actual	2007 Normalized	2008f Normalized	2009f Normalized
Residential (kWh)	200,397,263	196,943,158	197,359,181	197,649,413
GS<50 (kWh)	71,456,354	70,224,712	70,373,054	70,476,543
GS>50 (kWh)	163,433,488	160,616,501	160,955,787	161,192,485
(kW)	454,779	446,940	447,885	448,543
Street Lights (kWh)	4,119,804	4,119,804	4,132,164	4,144,560
(kW)	10,971	10,971	11,004	11,037
Sentinel Lights (kWh)	16,635	16,635	16,635	16,635
(kW)	17	17	17	17
USL (kWh)	501,647	501,647	501,647	501,647
Losses (kWh)	19,578,835	19,161,425	19,199,339	19,222,016
Total Wholesale kWh	459,504,027	451,583,883	452,537,807	453,203,301

Historic customer figures on an average annual basis are presented in Table 12 below. Table 12 also provides a trend forecast for the number of customers in each rate class for 2008 and 2009. Residential, GS<50 and GS>50 customer trend forecast is based average growth from 2004 to 2007. Street light is forecast to grow at 0.3%, while sentinel lights and USL are assumed to be constant at 2007 levels as no additional customer additions are anticipated.

Table 12 – Average Annual Customer Connections – Westario Power

	Residential	%chg	GS<50	%chg	GS>50	%chg	Street Light	%chg	Sent Light	%chg	USL
2003 ²	17,704		2,362		247		5,957		15		69
2004	17,686		2,338		245		6,218		6		70
2005	17,925	1.4%	2,329	-0.4%	247	0.8%	6,040	-2.9%	6	0.0%	70
2006	18,150	1.3%	2,338	0.4%	251	1.6%	6,041	0.0%	6	0.0%	70
2007	18,390	1.3%	2,354	0.7%	249	-0.7%	6,041	0.0%	6	0.0%	69
2008f	18,631	1.3%	2,360	0.2%	251	0.6%	6,059	0.3%	6	0.0%	69
2009f	18,875	1.3%	2,365	0.2%	252	0.6%	6,077	0.3%	6	0.0%	69

Explanation of Causes and Assumptions for the Volume Forecast

The volume forecast that is provided as an attachment in Exhibit 3, Tab 2, Schedule 1 is based on a number of factors including the effects of weather, the number of monthly peak days and monthly full time employment statistics within WPI's service area. If there are known numbers of connections in either the bridge year or test year for any specific customer class, they have been properly reflected in the volume forecast.

As evidenced by the results of Table 1 below, WPI has limited customer growth. WPI has very little opportunity for growth as its service territory is limited to the municipal boundaries that were established in 1999. Most of the growth within the 15 communities that WPI services is outside of its service territory.

Table 1 – Average Annual Customer Connections

	Residential	%Chg	GS<50	%Chg	GS>50	%Chg	Street Light	%Chg	Sent Light	% Chg	USL
2003	17,704		2,362		247		5,957		15		69
2004	17,686		2,338		245		6,218		6		70
2005	17,925	1.4%	2,329	-0.4%	247	0.8%	6,040	-2.9%	6	0.0%	70
2006	18,150	1.3%	2,338	0.4%	251	1.6%	6,041	0.0%	6	0.0%	69
2007	18,390	1.3%	2,354	0.7%	249	-0.7%	6,041	0.0%	6	0.0%	69
2008f	18,631	1.3%	2,360	0.2%	251	0.6%	6,059	0.3%	6	0.0%	69
2009f	18,875	1.3%	2,365	0.2%	252	0.6%	6,077	0.3%	6	0.0%	69

Further details of the causes and assumption for the Volume Forecast are provided in Exhibit 3, Tab 2, Schedule 1 ("Medium Term Weather Normalized Distribution System Load Forecast 2008 to 2009") as prepared by ERA.

Normalized Volume Forecast Table

Normalized volume forecast for historic, 2008 bridge year and 2009 test year is presented in the following tables:

Normalized Volume Consumption

Metered kWh

Customer Class Name	2006 EDR Approved	2006 Actual	Difference	% Chg	2006 Actual	2007 Actual	Difference	% Chg	2006 Actual	2007 Normalized	Difference	% Chg
Residential	203,562,663	197,424,289	-6,138,374	-3.02%	197,424,289	200,151,701	2,727,412	1.38%	197,424,289	196,943,158	-481,131	-0.24%
General Service Less Than 50 kW	70,522,040	68,830,543	-1,691,497	-2.40%	68,830,543	71,734,652	2,904,109	4.22%	68,830,543	70,224,712	1,394,169	2.03%
General Service 50 to 4,999 kW	152,787,963	156,157,695	3,369,732	2.21%	156,157,695	160,169,843	4,012,148	2.57%	156,157,695	160,616,501	4,458,806	2.86%
General Service 50 to 4,999 kW - TOU	1,653,261	1,693,917	40,656	2.46%	1,693,917	1,739,168	45,251	2.67%	1,693,917		-1,693,917	-100.00%
Unmetered Scattered Load	538,256	515,923	-22,333	-4.15%	515,923	498,104	-17,819	-3.45%	515,923	501,647	-14,276	-2.77%
Sentinel Lighting	13,229	13,900	671	5.07%	13,900	16,829	2,929	21.07%	13,900	16,635	2,735	19.68%
Street Lighting	4,824,146	4,611,611	-212,535	-4.41%	4,611,611	4,146,652	-464,959	-10.08%	4,611,611	4,119,804	-491,807	-10.66%
TOTAL	433,901,558	429,247,878	-4,653,680	-1.07%	429,247,878	438,456,949	9,209,071	2.15%	429,247,878	432,422,457	3,174,579	0.74%

Customer Class Name	2007 Normalized	2008 Estimated	Difference	% Chg	2008 Estimated	2008 Normalized	Difference	% Chg	2008 Normalized	2009 Normalized	Difference	% Chg
Residential	196,943,158	197,359,181	416,023	0.21%	197,359,181	197,359,181	0	0.00%	197,359,181	197,649,413	290,232	0.15%
General Service Less Than 50 kW	70,224,712	70,373,054	148,342	0.21%	70,373,054	70,373,054	0	0.00%	70,373,054	70,476,543	103,489	0.15%
General Service 50 to 4,999 kW	160,616,501	160,955,787	339,286	0.21%	160,955,787	160,955,787	0	0.00%	160,955,787	161,192,485	236,698	0.15%
General Service 50 to 4,999 kW - TOU											0	0.00%
Unmetered Scattered Load	501,647	501,647	0	0.00%	501,647	501,647	0	0.00%	501,647	501,647	0	0.00%
Sentinel Lighting	16,635	16,635	0	0.00%	16,635	16,635	0	0.00%	16,635	16,635	0	0.00%
Street Lighting	4,119,804	4,132,164	12,360	0.30%	4,132,164	4,132,164	0	0.00%	4,132,164	4,144,560	12,396	0.30%
TOTAL	432,422,457	433,338,468	916,011	0.21%	433,338,468	433,338,468	0	0.00%	433,338,468	433,981,283	642,815	0.15%

Metered KW

Customer Class Name	2006 EDR Approved	2006 Actual	Difference	% Chg	2006 Actual	2007 Actual	Difference	% Chg	2006 Actual	2007 Normalized	Difference	% Chg
General Service 50 to 4,999 kW	452,234	424,617	-27,617	-6.11%	424,617	443,366	18,749	4.42%	424,617	446,940	22,323	5.26%
General Service 50 to 4,999 kW - TOU	5,884	5,288	-596	-10.13%	5,288	5,444	156	2.95%	5,288		-5,288	-100.00%
Sentinel Lighting	39	19	-20	-51.28%	19	17	-2	-10.53%	19	17	-2	-10.53%
Street Lighting	13,579	13,129	-450	-3.31%	13,129	10,970	-2,159	-16.44%	13,129	10,971	-2,158	-16.44%
TOTAL	471,736	443,053	-28,683	-6.08%	443,053	459,797	16,744	3.78%	443,053	457,928	14,875	3.36%

Customer Class Name	2007 Normalized	2008 Estimated	Difference	% Chg	2008 Estimated	2008 Normalized	Difference	% Chg	2008 Normalized	2009 Normalized	Difference	% Chg
General Service 50 to 4,999 kW	446,940	447,885	945	0.21%	447,885	447,885	0	0.00%	447,885	448,543	658	0.15%
Sentinel Lighting	17	17	0	0.00%	17	17	0	0.00%	17	17	0	0.00%
Street Lighting	10,971	11,004	33	0.30%	11,004	11,004	0	0.00%	11,004	11,037	33	0.30%
TOTAL	457,928	458,906	978	0.21%	458,906	458,906	0	0.00%	458,906	459,597	691	0.15%

Customer Count Forecast Table

	Residential	%Chg	GS<50	%Chg	GS>50	%Chg	Street Light	%Chg	Sent Light	% Chg	USL
2003	17,704		2,362		247		5,957		15		69
2004	17,686		2,338		245		6,218		6		70
2005	17,925	1.4%	2,329	-0.4%	247	0.8%	6,040	-2.9%	6	0.0%	70
2006	18,150	1.3%	2,338	0.4%	251	1.6%	6,041	0.0%	6	0.0%	69
2007	18,390	1.3%	2,354	0.7%	249	-0.7%	6,041	0.0%	6	0.0%	69
2008f	18,631	1.3%	2,360	0.2%	251	0.6%	6,059	0.3%	6	0.0%	69
2009f	18,875	1.3%	2,365	0.2%	252	0.6%	6,077	0.3%	6	0.0%	69

Variance Analysis on Customer Count Forecast

Residential

2006 EDR Approved	17,881			
2006 Actual	18,150	269	1.5%	
2007 Actual	18,390	240	1.3%	
2008 Bridge	18,631	241	1.3%	
2009 Test	18,875	244	1.3%	

WPI has seen modest increases in the number of residential customers as evidenced by the figures above. Any new customers in this rate category are as a result of new connections in existing and/or new subdivisions. The increase of 269 customers from 2006 EDR Approved to 2006 Actual includes new customers for both 2005 and 2006; therefore the percentage increase is slightly higher than if only a single year was included. WPI believes that the figures forecast for the 2008 Bridge Year and 2009 Test Year are reasonable based on known subdivisions and the historical growth in this rate class.

General Service Less than 50kW

2006 EDR Approved	2,314		
2006 Actual	2,338	24	1.0%
2007 Actual	2,354	16	0.7%
2008 Bridge	2,360	6	0.2%
2009 Bridge	2,365	5	0.2%

WPI has seen modest increases in the number of General Service less than 50 kW customers as evidenced by the figures above. Any new customers in this rate category are as a result of new small commercial development. The increase of 24 customers from 2006 EDR Approved to 2006 Actual includes new customers for both 2005 and 2006; therefore the percentage increase is slightly higher than if only a single year was included. The historical year of 2007 had a higher increase in customers due to new commercial development in the municipalities of Hanover and Saugeen Shores. WPI believes that the figures forecast for the 2008 Bridge Year and 2009 Test Year are reasonable based on known future commercial development and historical growth in this rate class.

General Service Greater than 50 kW (to 4,999 kW)

2006 EDR Approved	246		
2006 Actual	251	5	2.0%
2007 Actual	249	(2)	(1.0%)
2008 Bridge	251	2	1.0%
2009 Actual	252	1	0.0%

WPI has seen almost no change in the number of General Service greater than 50 kW to 4,999 Kw customers as evidenced by the figures above. Any new customers in this rate category are as a result of new large commercial development and/or General Service less than 50 kW customers that have increased their consumption. The increase of 5 customers from 2006 Actual to 2006 EDR Approved includes new customers for both 2005 and 2006; therefore the percentage increase is slightly higher than if only a single year was included. The decrease in

2007 actuals was as a result of a shift in existing customers from this rate category to the General Service <50 kW rate category due to decreased consumption. WPI believes that the figures forecast for the 2008 Bridge Year and 2009 Test Year are reasonable based on known future commercial development and historical growth in this rate class.

Street lighting

2006 EDR Approved	6,030		
2006 Actual	6,041	11	0.0%
2007 Actual	6,041	0	0.0%
2008 Bridge	6,059	18	0.0%
2009 Test	6,077	18	0.0%

WPI has seen almost no change in the number of Street lighting connections as evidenced by the figures above. Any new customers in this rate category are as a result of new connections in new subdivisions. The increase of 11 customers from 2006 Actual to 2006 EDR Approved includes new connections for both 2005 and 2006; therefore the percentage increase is slightly higher than if only a single year was included. WPI believes that the figures forecast for the 2008 Bridge Year and 2009 Test Year are reasonable based on known future subdivisions and historical growth in this rate class.

Sentinel

2006 EDR Approved	15		
2006 Actual	6	(9)	(60.0%)
2007 Actual	6		
2008 Bridge	6		
2009 Test	6		

WPI has seen no change in the number of Sentinel customers as evidenced by the figures above. The Applicant is unable to explain the decrease in 9 customers from 2006 Actual to

2006 EDR Approved as they are unclear as to where the 2006 EDR Approved number comes from. WPI believes that the figures forecast for the 2008 Bridge Year and 2009 Test Year are reasonable based on no known future sentinel light customers and historical growth in this rate class.

Unmetered Scattered Load

2006 EDR Approved	70		
2006 Actual	70	0	
2007 Actual	69	(1)	(0.0%)
2008 Bridge	69		
2009 Bridge	69		

WPI has seen no change in the number of Unmetered Scattered Load customers as evidenced by the figures above. WPI believes that the figures forecast for the 2008 Bridge Year and 2009 Test Year are reasonable based on no known Unmetered Scattered Load customers and historical growth in this rate class.

Historical Average Consumption

The following tables show historic average consumption for historic, 2008 bridge year and 2009 test year:

Westario Power Inc.
Historical Average Consumption
Historic and Trend Forecast Energy Consumption

Residential	Actual	Weather	Difference	Difference	No. of	Weather
	KWh	Normalized kWh	kWh	%	Customers	Normalized kWh per Customer
2003	203,822,662	N/A	N/A	N/A		
2004	197,888,859	200,506,697	2,617,838	1.32%	17,686	11,337.03
2005	195,802,935	192,632,923	-3,170,012	-1.62%	17,925	10,746.61
2006	196,703,448	198,739,582	2,036,134	1.04%	18,150	10,949.84
2007	200,397,263	196,943,158	-3,454,105	-1.72%	18,390	10,709.25
2008F	N/A	197,359,181	N/A	N/A	18,631	10,593.05
2009F	N/A	197,649,413	N/A	N/A	18,875	10,471.49

GS < 50	Actual	Weather	Difference	Difference	No. of	Weather
	KWh	Normalized kWh	kWh	%	Customers	Normalized kWh per Customer
2003	75,281,676	N/A	N/A	N/A		
2004	70,856,084	71,793,427	937,343	1.32%	2,338	30,707.20
2005	69,391,252	68,267,821	-1,123,431	-1.62%	2,329	29,312.07
2006	69,114,782	69,830,209	715,427	1.04%	2,338	29,867.50
2007	71,456,354	70,224,712	-1,231,642	-1.72%	2,354	29,832.08
2008F	N/A	70,373,054	N/A	N/A	2,360	29,819.09
2009F	N/A	70,476,543	N/A	N/A	2,365	29,799.81

GS > 50	Actual	Weather	Difference	Difference	No. of	Weather
	KWh	Normalized kWh	kWh	%	Customers	Normalized kWh per Customer
2003	156,796,006	N/A	N/A	N/A		
2004	146,754,038	148,695,422	1,941,384	1.32%	245	606,920.09
2005	130,110,245	128,003,786	-2,106,459	-1.62%	247	518,233.95
2006	162,035,803	163,713,081	1,677,278	1.04%	251	652,243.35
2007	163,433,488	160,616,501	-2,816,987	-1.72%	249	645,046.19
2008F	N/A	160,955,787	N/A	N/A	251	641,258.12
2009F	N/A	161,192,485	N/A	N/A	252	639,652.72

Street lighting	Actual	Weather	Difference	Difference	No. of	Actual
	KWh	Normalized kWh	kWh	%	Connections	kWh per Connection
2003	4,873,517	N/A	N/A	N/A		
2004	4,104,812	N/A	N/A	N/A	6,218	660.15
2005	5,927,078	N/A	N/A	N/A	6,040	981.30
2006	4,644,694	N/A	N/A	N/A	6,041	768.86
2007	4,119,804	N/A	N/A	N/A	6,041	681.97
2008F	4,132,164	N/A	N/A	N/A	6,059	681.99
2009F	4,144,560	N/A	N/A	N/A	6,077	682.01

Sentinel lighting	Actual	Weather	Difference	Difference	No. of	Actual
	KWh	Normalized kWh	kWh	%	Customers	kWh per Customer
2003	12,638	N/A	N/A	N/A		
2004	10,741	N/A	N/A	N/A	6	1,790.17
2005	7,150	N/A	N/A	N/A	6	1,191.67
2006	14,130	N/A	N/A	N/A	6	2,355.00
2007	16,635	N/A	N/A	N/A	6	2,772.50
2008F	16,635	N/A	N/A	N/A	6	2,772.50
2009F	16,635	N/A	N/A	N/A	6	2,772.50

Unmetered scattered load	Actual	Weather	Difference	Difference	No. of	Actual
	KWh	Normalized kWh	kWh	%	Customers	kWh per Customer
2003	558,939	N/A	N/A	N/A		
2004	527,951	N/A	N/A	N/A	70	7,542.16
2005	587,965	N/A	N/A	N/A	70	8,399.50
2006	527,907	N/A	N/A	N/A	70	7,541.53
2007	501,647	N/A	N/A	N/A	69	7,270.25
2008F	501,647	N/A	N/A	N/A	69	7,270.25
2009F	501,647	N/A	N/A	N/A	69	7,270.25

Westario Power Inc.
Historical Average Consumption
Historic and Trend Forecast Demand

GS > 50	Actual	Weather	Difference	Difference	No. of	Weather
		Normalized			Customers	Normalized
	kW	kW	kW	%		kW per Customer
2003	464,758	N/A				
2004	451,969	457,948	5,979	1.32%	245	1,869.18
2005	449,395	442,119	-7,276	-1.62%	247	1,789.96
2006	437,885	442,418	4,533	1.04%	251	1,762.62
2007	454,779	446,940	-7,839	-1.72%	249	1,794.94
2008F	N/A	447,885	N/A	N/A	251	1,784.40
2009F	N/A	448,543	N/A	N/A	252	1,779.93

Street lighting	Actual	Weather	Difference	Difference	No. of	Actual
		Normalized			Connections	
	kW	kW	kW	%		kW per Connection
2003	13,573	N/A	N/A	N/A		
2004	9,943	N/A	N/A	N/A	6,218	1.60
2005	16,152	N/A	N/A	N/A	6,040	2.67
2006	13,130	N/A	N/A	N/A	6,041	2.17
2007	10,971	N/A	N/A	N/A	6,041	1.82
2008F	11,004	N/A	N/A	N/A	6,059	1.82
2009F	11,037	N/A	N/A	N/A	6,077	1.82

Sentinel lighting	Actual	Weather	Difference	Difference	No. of	Actual
		Normalized			Customers	
	kW	kW	kW	%		kW per Customer
2003	38	N/A	N/A	N/A		
2004	19	N/A	N/A	N/A	6	3.17
2005	20	N/A	N/A	N/A	6	3.33
2006	20	N/A	N/A	N/A	6	3.33
2007	17	N/A	N/A	N/A	6	2.83
2008F	17	N/A	N/A	N/A	6	2.83
2009F	17	N/A	N/A	N/A	6	2.83

Other Distribution Revenue

The following tables show a break out of other operating revenues for historic, 2008 bridge year
and 2009 test year:

Operating Revenue Summary

Other Operating Revenue ¹	2009 Projection	2008 Projection	Var \$	2008 Projection	2007 Normalized*	Var \$
4080-Distribution Services Revenue	56,625	55,893	732	55,893	53,469	2,424
4082-Retail Services Revenues	12,500	12,500	(0)	12,500	34,452	(21,952)
4084-Service Transaction Requests (STR) Revenues	2,000	2,000	0	2,000	1,760	240
4210-Rent from Electric Property	129,630	129,630		129,630	482,151	(352,521)
4215-Other Utility Operating Income					3	(3)
4225-Late Payment Charges	90,000	85,000	5,000	85,000	85,043	(43)
4235-Miscellaneous Service Revenues	330,800	292,645	38,155	292,645	290,965	1,680
4325-Revenues from Merchandise, Jobbing, Etc.	10,000	40,000	(30,000)	40,000		40,000
4355-Gain on Disposition of Utility and Other Property	500	7,500	(7,000)	7,500	33,227	(25,727)
4390-Miscellaneous Non-Operating Income	7,500	7,500		7,500		7,500
4405-Interest and Dividend Income	225,324	318,459	(93,135)	318,459	265,276	53,183
TOTAL OTHER OPERATING REVENUE ¹	864,879	951,127	(86,248)	951,127	1,246,346	(295,219)

* Amounts for account 4080 include (a) applicable service charges (e.g. SSS Admin Charge) and (b) the impact of distribution rates coming into effect Jan 1 rather than May 1

¹ Excludes pass-through charges and non-utility amounts

Operating Revenue Summary

Other Operating Revenue ¹	2007 Normalized*	2006 Normalized*	Var \$	2006 Normalized*	2006 EDR Approved	Var \$
4080-Distribution Services Revenue	53,469	54,511	(1,042)	54,511	56,384	(1,873)
4082-Retail Services Revenues	34,452	29,485	4,967	29,485	18,669	10,816
4084-Service Transaction Requests (STR) Revenues	1,760	1,664	96	1,664	76	1,588
4210-Rent from Electric Property	482,151	310,078	172,073	310,078	312,300	(2,222)
4215-Other Utility Operating Income	3	2,641	(2,638)	2,641		2,641
4225-Late Payment Charges	85,043	89,530	(4,487)	89,530	108,367	(18,837)
4235-Miscellaneous Service Revenues	290,965	159,654	131,311	159,654	152,817	6,837
4325-Revenues from Merchandise, Jobbing, Etc.						
4355-Gain on Disposition of Utility and Other Property	33,227		33,227			
4390-Miscellaneous Non-Operating Income					16	(16)
4405-Interest and Dividend Income	265,276	376,499	(111,223)	376,499	22,958	353,541
TOTAL OTHER OPERATING REVENUE ¹	1,246,346	1,024,062	222,284	1,024,062	671,587	352,475

* Amounts for account 4080 include (a) applicable service charges (e.g. SSS Admin Charge) and (b) the impact of distribution rates coming into effect Jan 1 rather than May 1

¹ Excludes pass-through charges and non-utility amounts

Materiality Analysis on Other Distribution Revenue

2006 Actual vs. 2006 EDR Approved

Other Operating Revenue	2006 Actual	2006 EDR Approved	Var \$	Var %
4080-Distribution Services Revenue	54,511	56,384	(1,873)	-3.3%

Decrease in distribution service revenues because there was a decrease in SSS customers as they transferred to retailer accounts.

Other Operating Revenue	2006 Actual	2006 EDR Approved	Var \$	Var %
4082-Retail Services Revenues	29,485	18,669	10,816	57.9%
4084-Service Transaction Requests (STR) Revenues	1,664	76	1,588	2089.5%

Increase in 2006 actual due to increased number of customers that enrolled with a retailer.

Other Operating Revenue	2006 Actual	2006 EDR Approved	Var \$	Var %
4210-Rent from Electric Property	310,078	312,300	(2,222)	-0.7%

Includes pole attachments and rental of utility owned property to an affiliate (Westario Power Services Inc.). Slight decrease due to decrease in pole rental revenues. Figures had been updated to accurately reflect number of attachments based on joint field audits.

Other Operating Revenue	2006 Actual	2006 EDR Approved	Var \$	Var %
4215-Other Utility Operating Income	2,641	0	2,641	100.0%

Includes water heater rental revenues. WPI stopped collecting revenues of water heater rentals in mid 2006.

Other Operating Revenue	2006 Actual	2006 EDR Approved	Var \$	Var %
4225-Late Payment Charges	89,530	108,367	(18,837)	-17.4%

In December of 2005; customers of WPI received the Ontario Price Credit. This credit was applied to customer accounts therefore decreasing the balance of WPI's outstanding accounts payable; which ultimately decreases late payment charges on outstanding balances. Because of WPI's more aggressive approach to overdue accounts decreased.

Other Operating Revenue	2006 Actual	2006 EDR Approved	Var \$	Var %
4235-Miscellaneous Service Revenues	159,654	152,817	6,837	4.5%

Variance due to greater quantity of actual than approved notification charges.

Other Operating Revenue	2006 Actual	2006 EDR Approved	Var \$	Var %
4405-Interest and Dividend Income	376,499	22,958	353,541	1539.9%

The 2006 EDR approved amount included projected interest on cash balances in current bank accounts. There were no interest amounts earned on bank balances in 2006; with the balance of this account representative of interest on regulatory assets.

2007 Actual vs. 2006 Actual

Other Operating Revenue	2007 Actual	2006 Actual	Var \$	Var %
4080-Distribution Services Revenue	53,469	54,511	(1,042)	-1.9%

Slight decrease due to SSS customers enrolling with a retailer.

Other Operating Revenue	2007 Actual	2006 Actual	Var \$	Var %
4082-Retail Services Revenues	34,452	29,485	4,967	16.8%
4084-Service Transaction Requests (STR) Revenues	1,760	1,664	96	5.8%

Increases due to SSS customers enrolling with retailers.

Other Operating Revenue	2007 Actual	2006 Actual	Var \$	Var %
4210-Rent from Electric Property	482,151	310,078	172,073	55.5%

Includes pole attachments and rental of utility owned property to an affiliate. Increase of approximately \$172,000 due to WPI renting utility owned property (namely the operational facility) to an affiliate (Westario Power Services Inc.).

Other Operating Revenue	2007 Actual	2006 Actual	Var \$	Var %
4215-Other Utility Operating Income	3	2,641	(2,638)	100.0%

Other utility operating income includes rental of water heater units. WPI stopped collecting revenues from water heater rental units mid 2006.

Other Operating Revenue	2007 Actual	2006 Actual	Var \$	Var %
4225-Late Payment Charges	85,043	89,530	(4,487)	-5.0%

Late payment charges on overdue accounts has dropped due to the average balance of Accounts Receivable decreasing by approximately \$100,000 year over year.

Other Operating Revenue	2007 Actual	2006 Actual	Var \$	Var %
4235-Miscellaneous Service Revenues	290,965	159,654	131,311	82.2%

This account includes all revenues from miscellaneous service charges. In 2007 there was a substantial increase in notification charges (approximately \$78,000) and a substantial increase in change of occupancy set up charges (approximately \$42,000). The balance of the increase was due to the charges associated with disconnection (approximately \$12,000). The increases associated with notification charges and disconnection charges are as a result of WPI's customer service policies consistent with WPI's Conditions of Service.

Other Operating Revenue	2007 Actual	2006 Actual	Var \$	Var %
4355-Gain on Disposition of Utility and Other Property	33,227	0	33,227	100.0%

Includes gain on sale of vacant land that was held in the municipality of Kincardine. This sale of land is considered a non-recurring event; as there are no other vacant lands available for sale.

Other Operating Revenue	2007 Actual	2006 Actual	Var \$	Var %
4405-Interest and Dividend Income	265,276	376,499	(111,223)	-29.5%

Includes interest earned on bank balances and interest on regulatory assets. Interest earned on bank balances in 2007 was approximately \$72,000 vs \$0 for 2006; this was a result of higher average bank balances. The balance of the account is attributed to interest on regulatory assets. The interest earned on regulatory assets in 2007 was approximately \$193,000 compared to approximately \$376,000 in 2006. This decrease in interest on regulatory assets is attributed to the fact that the balance of regulatory assets decreased due to the recovery of regulatory assets as approved in the 2006 EDR (EB-2005-0434) and the 2007 IRM (EB-2007-0591).

2008 Bridge vs. 2007 Actual

Other Operating Revenue	2008 Bridge	2007 Actual	Var \$	Var %
4080-Distribution Services Revenue	55,893	53,469	2,424	4.5%

Increase in monthly SSS Administrative charge as there are a number of retailer enrolled customers that have expired contracts and have not renewed with their existing retailer, or enrolled with a new retailer. Increase is also reflective of increases in numbers of customers in each of the rate categories.

Other Operating Revenue	2008 Bridge	2007 Actual	Var \$	Var %
4082-Retail Services Revenues	12,500	34,452	(21,952)	-63.7%
4084-Service Transaction Requests (STR) Revenues	2,000	1,760	240	13.6%

Decrease in number of retailer customers as contracts are expiring; also WPI is experiencing fewer retailer enrolled customers. The above accounts are also reflective of the fact that revenues in excess of the costs incurred in account 5315 (Customer Billing) that is related to retailer enrolled customers will be transferred to accounts 1518 (RCVA – Retail) and 1548 (RCVA – STR) respectively.

Other Operating Revenue	2008 Bridge	2007 Actual	Var \$	Var %
4210-Rent from Electric Property	129,630	482,151	(352,521)	-73.1%

Includes pole attachments and rental of utility owned property to an affiliate. On January 1, 2008 WPI amalgamated with its' two affiliates; Westario Power Services Inc., and Westario Power Holdings Inc. Because of the company's amalgamation, there are no longer revenues received for the rental of utility owned property (namely the operational facility and CIS system). The amount of \$129,630 is reflective of pole attachments only.

Other Operating Revenue	2008 Bridge	2007 Actual	Var \$	Var %
4225-Late Payment Charges	85,000	85,043	(43)	-0.1%

Other Operating Revenue	2008 Bridge	2007 Actual	Var \$	Var %
4235-Miscellaneous Service Revenues	292,645	290,965	1,680	0.6%

Slight increase due to increases in the notification charge and disconnection charges.

Other Operating Revenue	2008 Bridge	2007 Actual	Var \$	Var %
4325-Revenues from Merchandise, Jobbing, Etc.	40,000	0	40,000	100.0%

Prior to January 1, 2008; WPI did not engage in the sale of merchandise or jobbing as all jobbing was conducted by its' affiliate Westario Power Services Inc. As WPI amalgamated with its' affiliates Westario Power Services Inc. and Westario Power Holdings Inc.; amounts included in 2008 Bridge year include revenues from known third party jobs.

Other Operating Revenue	2008 Bridge	2007 Actual	Var \$	Var %
4355-Gain on Disposition of Utility and Other Property	7,500	33,227	(25,727)	-77.4%

The gain on disposition of utility and other property in 2007 included the sale of vacant land in the municipality of Kincardine. In the 2008 Bridge year, the anticipated gain on disposal of utility or other property is comprised of the gain on sale of a bucket truck, 2 pick up trucks and a small utility vehicle (van).

Other Operating Revenue	2008 Bridge	2007 Actual	Var \$	Var %
4390-Miscellaneous Non-Operating Income	7,500	0	7,500	100.0%

Miscellaneous non-operating income includes the proceeds of the sale of scrap wire. Based on the capital plan for 2008, it is estimated that the sale of replaced wire will net approximately \$7,500.

Other Operating Revenue	2008 Bridge	2007 Actual	Var \$	Var %
4405-Interest and Dividend Income	318,459	265,276	53,183	20.0%

Includes amounts for interest on bank balances and interest on regulatory assets. Projected interest on bank balances for the 2008 Bridge year is approximately \$75,000; consistent with the actual 2007 amount of \$72,000. The balance of the account is attributed to interest on regulatory assets. The projected interest on regulatory assets for the 2008 Bridge year is approximately \$243,000 compared to 2007 which was approximately \$193,000. This increase in interest on regulatory assets is attributed to higher regulatory asset balances and the fact that there is no recovery of the balances of regulatory assets as approved in the 2008 IRM (EB-2007-0865).

2009 Test vs. 2008 Bridge

Other Operating Revenue	2009 Test	2008 Bridge	Var \$	Var %
4080-Distribution Services Revenue	56,625	55,893	732	1.3%

Variance is due to anticipated increase in customers as per Exhibit 3, Tab 2, Schedule 2, Table 1.

Other Operating Revenue	2009 Test	2008 Bridge	Var \$	Var %
4225-Late Payment Charges	90,000	85,000	5,000	5.9%

Increase in late payment charges reflective of increases in accounts overdue in excess of 30 days, which is also reflected in increases in notification charges and increases in disconnection charges.

Other Operating Revenue	2009 Test	2008 Bridge	Var \$	Var %
4235-Miscellaneous Service Revenues	330,800	292,645	38,155	13.0%

Increase in miscellaneous services revenues has increased from the 2008 Bridge year to the 2009 Test year based on anticipated increases in notification charges and disconnection charges. The anticipated increase is based on WPI's current collection policy and trending on accounts that are overdue.

Other Operating Revenue	2009 Test	2008 Bridge	Var \$	Var %
4325-Revenues from Merchandise, Jobbing, Etc.	10,000	40,000	(30,000)	-75.0%

This account includes revenues from jobbing. The decrease in the 2009 Test year vs. the 2008 Bridge year is that the known third party works that WPI will be completing in 2009 has decreased since 2008.

Other Operating Revenue	2009 Test	2008 Bridge	Var \$	Var %
4355-Gain on Disposition of Utility and Other Property	500	7,500	(7,000)	-93.3%

The gains on disposition of utility and other property for the 2008 Bridge year included gains on disposal of a bucket truck, two pick up trucks and a small utility vehicle. In the 2009 test year; it is anticipated that WPI will be disposing of one pick up truck only. It is anticipated that the gain on the disposal of the vehicle will be approximately \$500.

Other Operating Revenue	2009 Test	2008 Bridge	Var \$	Var %
4405-Interest and Dividend Income	225,324	318,459	(93,135)	-29.2%

Includes interest on bank balances and interest on regulatory assets. In the 2008 Bridge year WPI has estimated interest on bank balances of approximately \$75,000; and interest on regulatory assets of approximately \$243,000. The decrease of interest in 2009 is a combination of a decrease in the prescribed rate on regulatory assets, decreases in cash reserves, and the anticipated recovery of specific regulatory assets. In 2009 WPI has estimated interest on bank balances of approximately \$30,000; and interest on regulatory assets of approximately \$195,000.

Other Operating Revenue	2009 Test	2008 Bridge	Var \$	Var %
4082-Retail Services Revenues	12,500	12,500	0	0.0%
4084-Service Transaction Requests (STR) Revenues	2,000	2,000	0	0.0%
4210-Rent from Electric Property	129,630	129,630	0	0.0%
4390-Miscellaneous Non-Operating Income	7,500	7,500	0	0.0%

There is no variance analysis on the above accounts as WPI does not anticipate any significant change in the 2009 Test year from the 2008 Bridge year.

Rate of Return on Other Distribution Revenue

In this application, WPI has applied for the same Specific Service Charges schedule as previously approved in the 2008 Tariffs of Rates and Charges (EB-2007-0865). The Specific Service Charges schedule follows the OEB recommended charges and as such WPI has no further information related to the rate of return on non-core delivery activities.

Distribution Revenue Data

Distribution revenue data for historic, 2008 bridge year and 2009 test year are presented as an attachment to this section.

Distribution Revenue Calculations

2006 EDR Approved	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge ¹	Distribution Revenue
Residential	17,881	11,384		\$0.0133		\$10.56	4,973,264
General Service Less Than 50 kW	2,314	30,476		\$0.0085		\$19.39	1,137,859
General Service 50 to 4,999 kW	246	621,089	1,838.350		\$2.2070	\$238.95	1,703,461
Unmetered Scattered Load	70	7,689		\$0.0451		\$4.38	27,955
Sentinel Lighting	16	827	2.438		\$6.9328	\$1.35	530
Street Lighting	6,030	800	2.252		\$1.9477	\$2.30	192,876
Gross Revenue (before Transformer Allowances)							8,035,943
Transformer Allowances (enter total credits as negative amount)							(72,097)
Total Revenue							7,963,846
Less: Low voltage charges embedded in distribution rates							(257,598)
DISTRIBUTION REVENUE							7,706,248

¹ Excluding Smart Meter Rate Adder

2006 Normalized Pro-forma *	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge ¹	Distribution Revenue
<i>* As if EDR rates became effective January 1st</i>							
Residential	18,150	10,950		\$0.0133		\$10.56	4,943,204
General Service Less Than 50 kW	2,338	29,867		\$0.0085		\$19.39	1,137,563
General Service 50 to 4,999 kW	250	654,852	1,769.672		\$2.2070	\$238.95	1,693,267
Unmetered Scattered Load	70	7,370		\$0.0451		\$4.38	26,947
Sentinel Lighting	6	2,317	3.167		\$6.9328	\$1.35	229
Street Lighting	6,041	763	2.173		\$1.9477	\$2.30	192,303
Gross Revenue (before Transformer Allowances)							7,993,513
Transformer Allowances (enter total credits as negative amount)							(40,271)
Total Revenue							7,953,242
Less: Low voltage charges embedded in distribution rates							(252,862)
DISTRIBUTION REVENUE							7,700,379

¹ Excluding Smart Meter Rate Adder

Distribution Revenue Calculations

2007 Normalized Pro-forma *	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge ¹	Distribution Revenue
<i>* As if EDR rates became effective January 1st</i>							
Residential	18,390	10,709		\$0.0134		\$10.66	4,991,487
General Service Less Than 50 kW	2,354	29,832		\$0.0086		\$19.56	1,156,463
General Service 50 to 4,999 kW	248	160,616,501	1,802		\$2.2269	\$241.10	1,712,804
Unmetered Scattered Load	68	7,325		\$0.0455		\$4.42	26,270
Sentinel Lighting	6	2,805	3		\$6.9982	\$1.36	217
Street Lighting	6,041	686	2		\$1.9652	\$2.32	189,740
Gross Revenue (before Transformer Allowances)							8,076,982
Transformer Allowances (enter total credits as negative amount)							(41,031)
Total Revenue							8,035,951
Less: Low voltage charges embedded in distribution rates							(253,457)
DISTRIBUTION REVENUE							7,782,494

¹ Excluding Smart Meter Rate Adder

2008 Projection *	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge ¹	Distribution Revenue
<i>* As if EDR rates became effective January 1st</i>							
Residential	18,631	10,593		\$0.0133		\$10.61	4,996,976
General Service Less Than 50 kW	2,360	29,819		\$0.0086		\$19.46	1,156,315
General Service 50 to 4,999 kW	251	641,258	1,784		\$2.2158	\$239.89	1,714,972
Unmetered Scattered Load	69	7,270		\$0.0453		\$4.40	26,368
Sentinel Lighting	6	2,773	3		\$6.9632	\$1.35	216
Street Lighting	6,059	682	2		\$1.9554	\$2.31	189,473
Gross Revenue (before Transformer Allowances)							8,084,320
Transformer Allowances							(69,720)
Total Revenue							8,014,600
Less: Low voltage charges embedded in distribution rates							(253,892)
DISTRIBUTION REVENUE							7,760,708

¹ Excluding Smart Meter Rate Adder

Distribution Revenue Calculations

2009 Projection	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge ¹	Distribution Revenue
<i>* As if EDR rates became effective January 1st</i>							
Residential	18,875	10,471		\$0.0161		\$12.84	6,088,311
General Service Less Than 50 kW	2,365	29,800		\$0.0106		\$24.05	1,431,632
General Service 50 to 4,999 kW	252	639,653	1,780		\$3.2034	\$239.89	2,162,305
Unmetered Scattered Load	69	7,270		\$0.0475		\$11.19	33,116
Sentinel Lighting	6	2,773	3		\$20.2204	\$3.92	626
Street Lighting	6,077	682	2		\$3.6270	\$4.28	352,489
Gross Revenue (before Transformer Allowances)							10,068,480
Transformer Allowances							(69,720)
Total Revenue							9,998,760
Less: Low voltage charges embedded in distribution rates							(733,477)
DISTRIBUTION REVENUE							9,265,283

¹ Excluding Smart Meter Rate Adder

1 **Description of Revenue Sharing**

2

3 WPI is a sole corporation that does not have any affiliate companies and therefore does
4 not participate in revenue sharing.

Calculation of LV Charges

The Applicant is requesting an increase in the current Low Voltage Rate which is currently included in the Distribution Rate of the Applicant. The proposed increase is based on the following information:

Projected 2008 LV Revenues:

Customer Class	Volume		Rate	Total Billed
Residential	197,359,181	kWh	0.0006	118,416
General Service Less Than 50 kW	70,373,054	kWh	0.000505882	35,600
General Service 50 to 4,999 kW	447,885	KW	0.217664449	97,489
Unmetered Scattered Load	501,647	kWh	0.000602661	302
Sentinel Lighting	17	kW	0.151260374	3
Street Lighting	11,004	kW	0.189245212	2,082
			TOTAL	253,892

The costs incurred by the Applicant far exceed the revenues from its' customers. The Applicant has accumulated an amount of \$865,375 in Account 1550 – LV Variance Account from 2006 to April 2009. In order to ensure that its current customers pay the true costs of the Low Voltage charges, and to ensure minimal variance amounts in the future the applicant is proposing the following charges:

2007 Low Voltage Costs	\$741,041
Actual 2007 Consumption	438,456,949 kWh
Normalized 2007 Consumption	432,422,457 kWh
Normalized 2009 Consumption	433,981,283 kWh
Decrease (2007 Actual vs. 2009 Normalized)	(4,475,666) kWh
Decrease	(1.02%)
2009 Proposed Low Voltage Costs	\$733,477
	(\$741,041 x (1-0.0102))

1 WPI proposes that the 2009 LV Charges be applied to the following rate classes:

2

Customer Class	Test Year Revenues Transmission - Connection	Class Share	Low Voltage Charges
Residential	1,151,411	47.9%	351,248
General Service Less Than 50 kW	364,944	15.2%	111,330
General Service 50 to 4,999 kW	868,873	36.1%	265,058
Unmetered Scattered Load	2,598	0.1%	792
Sentinel Lighting	26	0.0%	8
Street Lighting	16,526	0.7%	5,041
	2,404,377	100.0%	733,477

3

Overview of Operating Costs

Operating Costs

The operating costs presented in this exhibit represent the annual expenditures required to sustain WPI's Distribution Operations. The information presented in this exhibit is grouped into two categories. The first category includes Operation & Maintenance and Other Costs which include items such as Depreciation, Amortization and Depletion, Shared Services and Loss Adjustment Factor. The second category includes Income Tax and Ontario Capital Taxes.

OM&A Costs

The OM&A costs in this exhibit represent WPI's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and Government direction; and to maintain distribution business service quality and reliability at targeted performance levels. These costs also include providing services to customers connected to the Applicant's Distribution system, and meeting the service levels stipulated in the Standard Supply Service Code and the Retailer Settlement Codes.

The proposed OM&A cost expenditures for the 2009 test year result from a rigorous business planning and work prioritization process that reflects risk-based decision making to ensure that the most appropriate, cost effective solutions are put in place.

Income Tax and Ontario Capital Taxes

This information consists of detailed calculations of income taxes, and indemnity payments to the Province. Details of the expenditures are filed at Exhibit 4, Tab 3, Schedule 1.

Operating Budget Process

Each department Manager is responsible for the preparation of her/his departmental budget. Managers are directed to build up their department budgets using a "bottom up" approach, which requires each functional area, within Westario Power Inc. to build work plans that identify

1 resources, including labour, materials and other third party costs that are required to execute
2 the work plans. This approach ensures that budgets are developed to ensure that departmental
3 responsibilities are met and that anticipated works will be completed during the fiscal year. Any
4 significant variances from prior year must be explained and documented.

5
6 **Payroll-specific procedure:**

7 Each department manager meets with the Chief Executive Officer ('CEO') and the Chief
8 Financial Officer ('CFO') to determine the human resource level required in order to meet the
9 requirements of their department.

10
11 Once staffing levels are determined, the CFO calculates the labour costs of each department
12 including payroll burdens. Payroll burdens are calculated with the assistance of the Executive
13 Assistant who maintains all the payroll records.

14
15 Once the labour costs of each department are determined, the costs are provided to each of the
16 departmental managers to allocate appropriately in their departmental budgets.

17
18 A final budget package is produced to present to the Management Team for their review and
19 approval. Once approved by the CEO, the operating budget is presented to the WPI Board of
20 Directors for their approval.

21

Summary of Operating Costs

This section provides an OM&A Expenses Table that summarizes cost by account grouping. It includes the 2006 EDR-to-actual variance and the year-over-year variances.

OM&A* Expenses

Account Grouping	2009 Projection	2008 Projection	Var \$	2008 Projection	2007 Actual	Var \$
3500-Distribution Expenses - Operation	480,400	332,475	147,925	332,475	319,525	12,950
3550-Distribution Expenses - Maintenance	1,164,675	1,505,770	(341,095)	1,505,770	535,748	970,022
3650-Billing and Collecting	1,242,900	1,146,035	96,865	1,146,035	1,286,330	(140,295)
3700-Community Relations	35,500	23,470	12,030	23,470	485,353	(461,883)
3800-Administrative and General Expenses	1,888,350	1,850,765	37,585	1,850,765	1,907,783	(57,018)
3950-Taxes Other Than Income Taxes	56,600	50,600	6,000	50,600	118,449	(67,849)
TOTAL	4,868,425	4,909,115	(40,690)	4,909,115	4,653,188	255,927

* Operations, Maintenance & Administration

Note: Variances in excess of the below-noted
materiality threshold appear in **bold**

Total Distribution Expenses	6,629,571		6,086,828	
Materiality Threshold		66,296		60,868

OM&A* Expenses

Account Grouping	2007 Actual	2006 Actual	Var \$	2006 Actual	2006 EDR Approved	Var \$
3500-Distribution Expenses - Operation	319,525	406,210	(86,685)	406,210	97,077	309,133
3550-Distribution Expenses - Maintenance	535,748	1,184,709	(648,961)	1,184,709	945,725	238,984
3650-Billing and Collecting	1,286,330	1,139,082	147,248	1,139,082	1,207,662	(68,580)
3700-Community Relations	485,353	18,791	466,562	18,791	6,300	12,491
3800-Administrative and General Expenses	1,907,783	1,478,869	428,914	1,478,869	2,549,321	(1,070,452)
3950-Taxes Other Than Income Taxes	118,449	94,211	24,238	94,211	58,549	35,662
TOTAL	4,653,188	4,321,872	331,316	4,321,872	4,864,634	(542,762)

* Operations, Maintenance & Administration

Note: Variances in excess of the below-noted
materiality threshold appear in **bold**

Total Distribution Expenses	5,639,047		6,136,249	
Materiality Threshold		56,390		61,362

OM&A Costs

1
2
3
4
5

This section provides an OM&A Table showing WPI's operating cost data broken down by account, as set out by the Uniform System of Accounts, over the period 2006-2009 along with year over year variances.

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G5 Variance Analysis: Profit & Loss

Account Grouping	Account Description	2009 @ new dist. rates	2009 @ existing rates	Var \$	Var %
3000-Sales of Electricity	4006-Residential Energy Sales	(11,620,718)	(11,620,718)		
	4010-Commercial Energy Sales	(9,477,248)	(9,477,248)		
	4025-Street Lighting Energy Sales	(243,678)	(243,678)		
	4030-Sentinel Lighting Energy Sales	(978)	(978)		
	4035-General Energy Sales	(4,173,134)	(4,173,134)		
	4050-Revenue Adjustment				
	4055-Energy Sales for Resale				
	4062-Billed WMS	(2,902,710)	(2,902,710)		
	4066-Billed NW	(1,994,897)	(1,994,897)		
	4068-Billed CN	(2,404,377)	(2,404,377)		
3050-Revenues From Services - Distribution	4075-Billed-LV	(733,477)	(253,892)	(479,585)	(188.9%)
	4080-Distribution Services Revenue	(9,321,908)	(7,859,217)	(1,462,691)	(18.6%)
	4082-Retail Services Revenues	(12,500)	(12,500)		
	4084-Service Transaction Requests (STR) Revenues	(2,000)	(2,000)		
	4090-Electric Services Incidental to Energy Sales				
3100-Other Operating Revenues	4210-Rent from Electric Property	(129,630)	(129,630)		
	4215-Other Utility Operating Income				
	4220-Other Electric Revenues				
	4225-Late Payment Charges	(90,000)	(90,000)		
	4235-Miscellaneous Service Revenues	(330,800)	(330,800)		
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	(10,000)	(10,000)		
	4355-Gain on Disposition of Utility and Other Property	(500)	(500)		
	4375-Revenues from Non-Utility Operations				
	4380-Expenses of Non-Utility Operations				
	4385-Non-Utility Rental Income				
	4390-Miscellaneous Non-Operating Income	(7,500)	(7,500)		
3200-Investment Income	4405-Interest and Dividend Income	(225,324)	(225,324)		
3350-Power Supply Expenses	4705-Power Purchased	25,515,756	25,515,756		
	4708-Charges-WMS	2,902,710	2,902,710		
	4710-Cost of Power Adjustments				
	4714-Charges-NW	1,994,897	1,994,897		
	4716-Charges-CN	2,404,377	2,404,377		

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G5 Variance Analysis: Profit & Loss

Account Grouping	Account Description	2009 @ new dist. rates	2009 @ existing rates	Var \$	Var %
3500-Distribution Expenses - Operation	4750-Charges-LV	733,477	253,892	479,585	188.9%
	5010-Load Dispatching				
	5016-Distribution Station Equipment - Operation Labour				
	5017-Distribution Station Equipment - Operation Supplies and Expenses				
	5020-Overhead Distribution Lines and Feeders - Operation Labour				
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses				
	5035-Overhead Distribution Transformers-Operation				
	5040-Underground Distribution Lines and Feeders - Operation Labour	469,400	469,400		
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	10,000	10,000		
	5055-Underground Distribution Transformers - Operation				
	5065-Meter Expense				
	5070-Customer Premises - Operation Labour				
	5075-Customer Premises - Materials and Expenses	1,000	1,000		
	5085-Miscellaneous Distribution Expense				
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	16,775	16,775		
	5110-Maintenance of Buildings and Fixtures - Distribution Stations				
	5114-Maintenance of Distribution Station Equipment	246,800	246,800		
	5120-Maintenance of Poles, Towers and Fixtures	77,400	77,400		
	5125-Maintenance of Overhead Conductors and Devices	131,200	131,200		
	5130-Maintenance of Overhead Services	106,600	106,600		
	5135-Overhead Distribution Lines and Feeders - Right of Way	270,900	270,900		

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G5 Variance Analysis: Profit & Loss

Account Grouping	Account Description	2009 @ new dist. rates	2009 @ existing rates	Var \$	Var %
	5145-Maintenance of Underground Conduit				
	5150-Maintenance of Underground Conductors and Devices				
	5155-Maintenance of Underground Services	112,000	112,000		
	5160-Maintenance of Line Transformers	108,000	108,000		
	5175-Maintenance of Meters	95,000	95,000		
	5190-Water Heater Controls - Labour				
	5195-Maintenance of Other Installations on Customer Premises				
3650-Billing and Collecting	5305-Supervision	16,775	16,775		
	5310-Meter Reading Expense	272,000	272,000		
	5315-Customer Billing	387,725	387,725		
	5320-Collecting	416,400	416,400		
	5335-Bad Debt Expense	150,000	150,000		
	5340-Miscellaneous Customer Accounts Expenses				
3700-Community Relations	5410-Community Relations - Sundry	20,500	20,500		
	5415-Energy Conservation				
	5420-Community Safety Program	15,000	15,000		
	5425-Miscellaneous Customer Service and Informational Expenses				
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	130,000	130,000		
	5610-Management Salaries and Expenses	689,400	689,400		
	5615-General Administrative Salaries and Expenses	143,300	143,300		
	5620-Office Supplies and Expenses	368,650	368,650		
	5630-Outside Services Employed	178,500	178,500		
	5635-Property Insurance	101,125	101,125		
	5640-Injuries and Damages	2,500	2,500		
	5645-Employee Pensions and Benefits				
	5655-Regulatory Expenses	140,000	140,000		
	5660-General Advertising Expenses	3,000	3,000		
	5665-Miscellaneous General Expenses	33,550	33,550		
	5670-Rent				
	5675-Maintenance of General Plant	98,325	98,325		

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G5 Variance Analysis: Profit & Loss

Account Grouping	Account Description	2009 @ new dist. rates	2009 @ existing rates	Var \$	Var %
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	1,829,713	1,829,713		
	5725-Miscellaneous Amortization				
3900-Interest Expense	6005-Interest on Long Term Debt	802,083	802,083		
	6035-Other Interest Expense	40,000	40,000		
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	56,600	56,600		
4000-Income Taxes	6110-Income Taxes	897,156	456,436	440,720	96.6%
	6115-Provision for Future Income Taxes				
4100-Extraordinary & Other Items	6205-Donations				
Net Income		1,692,784	670,813	1,021,971	152.3%

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G5 Variance Analysis: Profit & Loss

Account Grouping	Account Description	2009 @ existing rates	2008 Projection	Var \$	Var %
3000-Sales of Electricity	4006-Residential Energy Sales	(11,620,718)	(11,603,654)	(17,064)	(0.1%)
	4010-Commercial Energy Sales	(9,477,248)	(9,463,331)	(13,917)	(0.1%)
	4025-Street Lighting Energy Sales	(243,678)	(242,949)	(729)	(0.3%)
	4030-Sentinel Lighting Energy Sales	(978)	(978)		
	4035-General Energy Sales	(4,173,134)	(4,167,050)	(6,085)	(0.1%)
	4050-Revenue Adjustment				
	4055-Energy Sales for Resale				
	4062-Billed WMS	(2,902,710)	(2,898,410)	(4,300)	(0.1%)
	4066-Billed NW	(1,994,897)	(1,991,951)	(2,946)	(0.1%)
	4068-Billed CN	(2,404,377)	(2,400,826)	(3,551)	(0.1%)
	4075-Billed-LV	(253,892)	(253,892)	(0)	(0.0%)
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	(7,859,217)	(7,816,601)	(42,616)	(0.5%)
	4082-Retail Services Revenues	(12,500)	(12,500)	0	0.0%
	4084-Service Transaction Requests (STR) Revenues	(2,000)	(2,000)	(0)	(0.0%)
	4090-Electric Services Incidental to Energy Sales				
3100-Other Operating Revenues	4210-Rent from Electric Property	(129,630)	(129,630)		
	4215-Other Utility Operating Income				
	4220-Other Electric Revenues				
	4225-Late Payment Charges	(90,000)	(85,000)	(5,000)	(5.9%)
	4235-Miscellaneous Service Revenues	(330,800)	(292,645)	(38,155)	(13.0%)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	(10,000)	(40,000)	30,000	75.0%
	4355-Gain on Disposition of Utility and Other Property	(500)	(7,500)	7,000	93.3%
	4375-Revenues from Non-Utility Operations				
	4380-Expenses of Non-Utility Operations				
	4385-Non-Utility Rental Income				
	4390-Miscellaneous Non-Operating Income	(7,500)	(7,500)		
3200-Investment Income	4405-Interest and Dividend Income	(225,324)	(318,459)	93,135	29.2%
3350-Power Supply Expenses	4705-Power Purchased	25,515,756	25,477,962	37,794	0.1%
	4708-Charges-WMS	2,902,710	2,898,410	4,300	0.1%
	4710-Cost of Power Adjustments				
	4714-Charges-NW	1,994,897	1,991,951	2,946	0.1%
	4716-Charges-CN	2,404,377	2,400,826	3,551	0.1%

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G5 Variance Analysis: Profit & Loss

Account Grouping	Account Description	2009 @ existing rates	2008 Projection	Var \$	Var %
3500-Distribution Expenses - Operation	4750-Charges-LV	253,892	253,892	0	0.0%
	5010-Load Dispatching				
	5016-Distribution Station Equipment - Operation Labour				
	5017-Distribution Station Equipment - Operation Supplies and Expenses				
	5020-Overhead Distribution Lines and Feeders - Operation Labour				
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses				
	5035-Overhead Distribution Transformers-Operation				
	5040-Underground Distribution Lines and Feeders - Operation Labour	469,400	322,475	146,925	45.6%
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	10,000	10,000		
	5055-Underground Distribution Transformers - Operation				
	5065-Meter Expense				
	5070-Customer Premises - Operation Labour				
	5075-Customer Premises - Materials and Expenses	1,000		1,000	
	5085-Miscellaneous Distribution Expense				
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	16,775	18,300	(1,525)	(8.3%)
	5110-Maintenance of Buildings and Fixtures - Distribution Stations		25,900	(25,900)	(100.0%)
	5114-Maintenance of Distribution Station Equipment	246,800	204,750	42,050	20.5%
	5120-Maintenance of Poles, Towers and Fixtures	77,400	58,920	18,480	31.4%
	5125-Maintenance of Overhead Conductors and Devices	131,200	27,625	103,575	374.9%
	5130-Maintenance of Overhead Services	106,600	74,650	31,950	42.8%
	5135-Overhead Distribution Lines and Feeders - Right of Way	270,900	230,250	40,650	17.7%

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G5 Variance Analysis: Profit & Loss

Account Grouping	Account Description	2009 @ existing rates	2008 Projection	Var \$	Var %
	5145-Maintenance of Underground Conduit				
	5150-Maintenance of Underground Conductors and Devices		4,600	(4,600)	(100.0%)
	5155-Maintenance of Underground Services	112,000	98,000	14,000	14.3%
	5160-Maintenance of Line Transformers	108,000	453,600	(345,600)	(76.2%)
	5175-Maintenance of Meters	95,000	309,175	(214,175)	(69.3%)
	5190-Water Heater Controls - Labour				
	5195-Maintenance of Other Installations on Customer Premises				
3650-Billing and Collecting	5305-Supervision	16,775	18,300	(1,525)	(8.3%)
	5310-Meter Reading Expense	272,000	272,000		
	5315-Customer Billing	387,725	371,035	16,690	4.5%
	5320-Collecting	416,400	384,700	31,700	8.2%
	5335-Bad Debt Expense	150,000	100,000	50,000	50.0%
	5340-Miscellaneous Customer Accounts Expenses				
3700-Community Relations	5410-Community Relations - Sundry	20,500	13,470	7,030	52.2%
	5415-Energy Conservation				
	5420-Community Safety Program	15,000	10,000	5,000	50.0%
	5425-Miscellaneous Customer Service and Informational Expenses				
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	130,000	128,125	1,875	1.5%
	5610-Management Salaries and Expenses	689,400	631,100	58,300	9.2%
	5615-General Administrative Salaries and Expenses	143,300	145,150	(1,850)	(1.3%)
	5620-Office Supplies and Expenses	368,650	326,125	42,525	13.0%
	5630-Outside Services Employed	178,500	311,490	(132,990)	(42.7%)
	5635-Property Insurance	101,125	97,125	4,000	4.1%
	5640-Injuries and Damages	2,500	2,500		
	5645-Employee Pensions and Benefits				
	5655-Regulatory Expenses	140,000	59,900	80,100	133.7%
	5660-General Advertising Expenses	3,000	11,900	(8,900)	(74.8%)
	5665-Miscellaneous General Expenses	33,550	36,600	(3,050)	(8.3%)
	5670-Rent				
	5675-Maintenance of General Plant	98,325	100,750	(2,425)	(2.4%)

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G5 Variance Analysis: Profit & Loss

Account Grouping	Account Description	2009 @ existing rates	2008 Projection	Var \$	Var %
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	1,829,713	1,720,456	109,257	6.4%
	5725-Miscellaneous Amortization				
3900-Interest Expense	6005-Interest on Long Term Debt	802,083	775,350	26,733	3.4%
	6035-Other Interest Expense	40,000	38,100	1,900	5.0%
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	56,600	50,600	6,000	11.9%
4000-Income Taxes	6110-Income Taxes	456,436	801,261	(344,825)	(43.0%)
	6115-Provision for Future Income Taxes				
4100-Extraordinary & Other Items	6205-Donations				
Net Income		670,813	467,553	203,261	43.5%

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G5 Variance Analysis: Profit & Loss

Account Grouping	Account Description	2008 Projection	2007 Actual	Var \$	Var %
3000-Sales of Electricity	4006-Residential Energy Sales	(11,603,654)	(8,750,788)	(2,852,866)	(32.6%)
	4010-Commercial Energy Sales	(9,463,331)	(3,679,779)	(5,783,552)	(157.2%)
	4025-Street Lighting Energy Sales	(242,949)	(301,762)	58,813	19.5%
	4030-Sentinel Lighting Energy Sales	(978)	(908)	(70)	(7.7%)
	4035-General Energy Sales	(4,167,050)	(5,991,217)	1,824,167	30.4%
	4050-Revenue Adjustment				
	4055-Energy Sales for Resale		(6,031,118)	6,031,118	100.0%
	4062-Billed WMS	(2,898,410)	(2,365,065)	(533,345)	(22.6%)
	4066-Billed NW	(1,991,951)	(2,231,857)	239,906	10.7%
	4068-Billed CN	(2,400,826)	(2,090,810)	(310,016)	(14.8%)
3050-Revenues From Services - Distribution	4075-Billed-LV	(253,892)	(250,017)	(3,875)	(1.5%)
	4080-Distribution Services Revenue	(7,816,601)	(7,771,563)	(45,038)	(0.6%)
	4082-Retail Services Revenues	(12,500)	(12,349)	(151)	(1.2%)
	4084-Service Transaction Requests (STR) Revenues	(2,000)	(1,760)	(240)	(13.6%)
	4090-Electric Services Incidental to Energy Sales				
3100-Other Operating Revenues	4210-Rent from Electric Property	(129,630)	(482,151)	352,521	73.1%
	4215-Other Utility Operating Income		(3)	3	100.0%
	4220-Other Electric Revenues				
	4225-Late Payment Charges	(85,000)	(85,043)	43	0.1%
	4235-Miscellaneous Service Revenues	(292,645)	(290,965)	(1,680)	(0.6%)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	(40,000)		(40,000)	
	4355-Gain on Disposition of Utility and Other Property	(7,500)	(33,227)	25,727	77.4%
	4375-Revenues from Non-Utility Operations		(132,503)	132,503	100.0%
	4380-Expenses of Non-Utility Operations		112,724	(112,724)	(100.0%)
	4385-Non-Utility Rental Income				
3200-Investment Income	4390-Miscellaneous Non-Operating Income	(7,500)		(7,500)	
	4405-Interest and Dividend Income	(318,459)	(265,276)	(53,183)	(20.0%)
3350-Power Supply Expenses	4705-Power Purchased	25,477,962	24,755,573	722,389	2.9%
	4708-Charges-WMS	2,898,410	2,365,065	533,345	22.6%
	4710-Cost of Power Adjustments				
	4714-Charges-NW	1,991,951	2,231,857	(239,906)	(10.7%)
	4716-Charges-CN	2,400,826	2,090,810	310,016	14.8%

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G5 Variance Analysis: Profit & Loss

Account Grouping	Account Description	2008 Projection	2007 Actual	Var \$	Var %
3500-Distribution Expenses - Operation	4750-Charges-LV	253,892	250,017	3,875	1.5%
	5010-Load Dispatching				
	5016-Distribution Station Equipment - Operation Labour				
	5017-Distribution Station Equipment - Operation Supplies and Expenses		374	(374)	(100.0%)
	5020-Overhead Distribution Lines and Feeders - Operation Labour		20,083	(20,083)	(100.0%)
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses				
	5035-Overhead Distribution Transformers-Operation		866	(866)	(100.0%)
	5040-Underground Distribution Lines and Feeders - Operation Labour	322,475	221,309	101,166	45.7%
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	10,000	9,762	238	2.4%
	5055-Underground Distribution Transformers - Operation				
	5065-Meter Expense		34,359	(34,359)	(100.0%)
	5070-Customer Premises - Operation Labour				
	5075-Customer Premises - Materials and Expenses		312	(312)	(100.0%)
	5085-Miscellaneous Distribution Expense		32,460	(32,460)	(100.0%)
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	18,300	63,913	(45,613)	(71.4%)
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	25,900	5,562	20,338	365.7%
	5114-Maintenance of Distribution Station Equipment	204,750	(108,206)	312,956	289.2%
	5120-Maintenance of Poles, Towers and Fixtures	58,920	72,718	(13,798)	(19.0%)
	5125-Maintenance of Overhead Conductors and Devices	27,625	130,569	(102,944)	(78.8%)
	5130-Maintenance of Overhead Services	74,650	53,347	21,303	39.9%
	5135-Overhead Distribution Lines and Feeders - Right of Way	230,250	156,758	73,492	46.9%

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G5 Variance Analysis: Profit & Loss

Account Grouping	Account Description	2008 Projection	2007 Actual	Var \$	Var %
	5145-Maintenance of Underground Conduit		19,589	(19,589)	(100.0%)
	5150-Maintenance of Underground Conductors and Devices	4,600	550	4,050	736.4%
	5155-Maintenance of Underground Services	98,000	61,846	36,154	58.5%
	5160-Maintenance of Line Transformers	453,600	65,974	387,626	587.5%
	5175-Maintenance of Meters	309,175	13,128	296,047	2255.1%
	5190-Water Heater Controls - Labour				
	5195-Maintenance of Other Installations on Customer Premises				
3650-Billing and Collecting	5305-Supervision	18,300	63,913	(45,613)	(71.4%)
	5310-Meter Reading Expense	272,000	266,128	5,872	2.2%
	5315-Customer Billing	371,035	348,180	22,855	6.6%
	5320-Collecting	384,700	448,125	(63,425)	(14.2%)
	5335-Bad Debt Expense	100,000	159,936	(59,936)	(37.5%)
	5340-Miscellaneous Customer Accounts Expenses		48	(48)	(100.0%)
3700-Community Relations	5410-Community Relations - Sundry	13,470	185	13,285	7181.1%
	5415-Energy Conservation		476,540	(476,540)	(100.0%)
	5420-Community Safety Program	10,000	7,356	2,644	35.9%
	5425-Miscellaneous Customer Service and Informational Expenses		1,272	(1,272)	(100.0%)
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	128,125	96,578	31,547	32.7%
	5610-Management Salaries and Expenses	631,100	427,358	203,742	47.7%
	5615-General Administrative Salaries and Expenses	145,150	118,513	26,637	22.5%
	5620-Office Supplies and Expenses	326,125	271,947	54,178	19.9%
	5630-Outside Services Employed	311,490	353,621	(42,131)	(11.9%)
	5635-Property Insurance	97,125	89,910	7,215	8.0%
	5640-Injuries and Damages	2,500	420	2,080	495.2%
	5645-Employee Pensions and Benefits				
	5655-Regulatory Expenses	59,900	64,660	(4,760)	(7.4%)
	5660-General Advertising Expenses	11,900	17,826	(5,926)	(33.2%)
	5665-Miscellaneous General Expenses	36,600	127,827	(91,227)	(71.4%)
	5670-Rent		221,250	(221,250)	(100.0%)
	5675-Maintenance of General Plant	100,750	117,873	(17,123)	(14.5%)

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G5 Variance Analysis: Profit & Loss

Account Grouping	Account Description	2008 Projection	2007 Actual	Var \$	Var %
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	1,720,456	1,433,640	286,816	20.0%
	5725-Miscellaneous Amortization				
3900-Interest Expense	6005-Interest on Long Term Debt	775,350	1,170,479	(395,129)	(33.8%)
	6035-Other Interest Expense	38,100	55,296	(17,196)	(31.1%)
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	50,600	118,449	(67,849)	(57.3%)
4000-Income Taxes	6110-Income Taxes	801,261	1,052,000	(250,739)	(23.8%)
	6115-Provision for Future Income Taxes		(511,000)	511,000	100.0%
4100-Extraordinary & Other Items	6205-Donations		11,580	(11,580)	(100.0%)
Net Income		467,553	1,096,932	(629,379)	(57.4%)

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G5 Variance Analysis: Profit & Loss

Account Grouping	Account Description	2007 Actual	2006 Actual	Var \$	Var %
3000-Sales of Electricity	4006-Residential Energy Sales	(8,750,788)	(9,127,900)	377,112	4.1%
	4010-Commercial Energy Sales	(3,679,779)	(3,663,128)	(16,651)	(0.5%)
	4025-Street Lighting Energy Sales	(301,762)	(333,997)	32,235	9.7%
	4030-Sentinel Lighting Energy Sales	(908)	(791)	(117)	(14.8%)
	4035-General Energy Sales	(5,991,217)	(6,252,567)	261,350	4.2%
	4050-Revenue Adjustment				
	4055-Energy Sales for Resale	(6,031,118)	(5,104,200)	(926,918)	(18.2%)
	4062-Billed WMS	(2,365,065)	(2,284,640)	(80,425)	(3.5%)
	4066-Billed NW	(2,231,857)	(2,199,030)	(32,827)	(1.5%)
	4068-Billed CN	(2,090,810)	(1,999,929)	(90,881)	(4.5%)
	4075-Billed-LV	(250,017)	(103,475)	(146,542)	(141.6%)
	4080-Distribution Services Revenue	(7,771,563)	(7,911,643)	140,080	1.8%
	4082-Retail Services Revenues	(12,349)	(12,715)	366	2.9%
	4084-Service Transaction Requests (STR) Revenues	(1,760)	(1,664)	(96)	(5.8%)
	4090-Electric Services Incidental to Energy Sales				
3100-Other Operating Revenues	4210-Rent from Electric Property	(482,151)	(310,078)	(172,073)	(55.5%)
	4215-Other Utility Operating Income	(3)	(2,641)	2,638	99.9%
	4220-Other Electric Revenues		(9,834)	9,834	100.0%
	4225-Late Payment Charges	(85,043)	(89,530)	4,487	5.0%
	4235-Miscellaneous Service Revenues	(290,965)	(159,654)	(131,311)	(82.2%)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.				
	4355-Gain on Disposition of Utility and Other Property	(33,227)		(33,227)	
	4375-Revenues from Non-Utility Operations	(132,503)		(132,503)	
	4380-Expenses of Non-Utility Operations	112,724	52,194	60,530	116.0%
	4385-Non-Utility Rental Income				
3200-Investment Income	4390-Miscellaneous Non-Operating Income				
	4405-Interest and Dividend Income	(265,276)	(376,499)	111,223	29.5%
3350-Power Supply Expenses	4705-Power Purchased	24,755,573	24,482,583	272,990	1.1%
	4708-Charges-WMS	2,365,065	2,284,640	80,425	3.5%
	4710-Cost of Power Adjustments				
	4714-Charges-NW	2,231,857	2,199,030	32,827	1.5%
	4716-Charges-CN	2,090,810	1,999,929	90,881	4.5%

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G5 Variance Analysis: Profit & Loss

Account Grouping	Account Description	2007 Actual	2006 Actual	Var \$	Var %
3500-Distribution Expenses - Operation	4750-Charges-LV	250,017	103,475	146,542	141.6%
	5010-Load Dispatching		2,449	(2,449)	(100.0%)
	5016-Distribution Station Equipment - Operation Labour		12,030	(12,030)	(100.0%)
	5017-Distribution Station Equipment - Operation Supplies and Expenses	374		374	
	5020-Overhead Distribution Lines and Feeders - Operation Labour	20,083	6,908	13,175	190.7%
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses				
	5035-Overhead Distribution Transformers-Operation	866	1,927	(1,061)	(55.1%)
	5040-Underground Distribution Lines and Feeders - Operation Labour	221,309	269,258	(47,949)	(17.8%)
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	9,762	16,428	(6,666)	(40.6%)
	5055-Underground Distribution Transformers - Operation		482	(482)	(100.0%)
	5065-Meter Expense	34,359	59,293	(24,934)	(42.1%)
	5070-Customer Premises - Operation Labour		713	(713)	(100.0%)
	5075-Customer Premises - Materials and Expenses	312		312	
	5085-Miscellaneous Distribution Expense	32,460	36,722	(4,262)	(11.6%)
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	63,913	44,337	19,576	44.2%
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	5,562	67,324	(61,762)	(91.7%)
	5114-Maintenance of Distribution Station Equipment	(108,206)	79,827	(188,033)	(235.6%)
	5120-Maintenance of Poles, Towers and Fixtures	72,718	92,575	(19,857)	(21.4%)
	5125-Maintenance of Overhead Conductors and Devices	130,569	282,089	(151,520)	(53.7%)
	5130-Maintenance of Overhead Services	53,347	91,758	(38,411)	(41.9%)
	5135-Overhead Distribution Lines and Feeders - Right of Way	156,758	193,255	(36,497)	(18.9%)

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G5 Variance Analysis: Profit & Loss

Account Grouping	Account Description	2007 Actual	2006 Actual	Var \$	Var %
	5145-Maintenance of Underground Conduit	19,589	64,914	(45,325)	(69.8%)
	5150-Maintenance of Underground Conductors and Devices	550	55,227	(54,677)	(99.0%)
	5155-Maintenance of Underground Services	61,846	106,517	(44,671)	(41.9%)
	5160-Maintenance of Line Transformers	65,974	100,486	(34,512)	(34.3%)
	5175-Maintenance of Meters	13,128	6,164	6,964	113.0%
	5190-Water Heater Controls - Labour		95	(95)	(100.0%)
	5195-Maintenance of Other Installations on Customer Premises		141	(141)	(100.0%)
3650-Billing and Collecting	5305-Supervision	63,913	44,337	19,576	44.2%
	5310-Meter Reading Expense	266,128	261,687	4,441	1.7%
	5315-Customer Billing	348,180	399,891	(51,711)	(12.9%)
	5320-Collecting	448,125	426,995	21,130	4.9%
	5335-Bad Debt Expense	159,936	6,101	153,835	2521.5%
	5340-Miscellaneous Customer Accounts Expenses	48	71	(23)	(32.4%)
3700-Community Relations	5410-Community Relations - Sundry	185		185	
	5415-Energy Conservation	476,540	14,494	462,046	3187.8%
	5420-Community Safety Program	7,356	2,665	4,691	176.0%
	5425-Miscellaneous Customer Service and Informational Expenses	1,272	1,632	(360)	(22.1%)
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	96,578	89,008	7,570	8.5%
	5610-Management Salaries and Expenses	427,358	425,925	1,433	0.3%
	5615-General Administrative Salaries and Expenses	118,513	112,242	6,271	5.6%
	5620-Office Supplies and Expenses	271,947	223,506	48,441	21.7%
	5630-Outside Services Employed	353,621	240,708	112,913	46.9%
	5635-Property Insurance	89,910	66,825	23,085	34.5%
	5640-Injuries and Damages	420	584	(164)	(28.1%)
	5645-Employee Pensions and Benefits				
	5655-Regulatory Expenses	64,660	93,704	(29,044)	(31.0%)
	5660-General Advertising Expenses	17,826	15,187	2,639	17.4%
	5665-Miscellaneous General Expenses	127,827	88,673	39,154	44.2%
	5670-Rent	221,250	50,983	170,267	334.0%
	5675-Maintenance of General Plant	117,873	71,524	46,349	64.8%

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G5 Variance Analysis: Profit & Loss

Account Grouping	Account Description	2007 Actual	2006 Actual	Var \$	Var %
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	1,433,640	1,317,175	116,465	8.8%
	5725-Miscellaneous Amortization		21,150	(21,150)	(100.0%)
3900-Interest Expense	6005-Interest on Long Term Debt	1,170,479	568,662	601,817	105.8%
	6035-Other Interest Expense	55,296	81,827	(26,531)	(32.4%)
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	118,449	94,211	24,238	25.7%
4000-Income Taxes	6110-Income Taxes	1,052,000	1,245,000	(193,000)	(15.5%)
	6115-Provision for Future Income Taxes	(511,000)	(360,824)	(150,176)	(41.6%)
4100-Extraordinary & Other Items	6205-Donations	11,580	2,973	8,607	289.5%
Net Income		1,096,932	1,624,229	(527,297)	(32.5%)

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G5 Variance Analysis: Profit & Loss

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var \$	Var %
3000-Sales of Electricity	4006-Residential Energy Sales	(9,127,900)	(8,579,947)	(547,953)	(6.4%)
	4010-Commercial Energy Sales	(3,663,128)	(3,236,639)	(426,489)	(13.2%)
	4025-Street Lighting Energy Sales	(333,997)	(245,357)	(88,640)	(36.1%)
	4030-Sentinel Lighting Energy Sales	(791)	(578)	(213)	(36.9%)
	4035-General Energy Sales	(6,252,567)	(7,390,935)	1,138,368	15.4%
	4050-Revenue Adjustment		147,953	(147,953)	(100.0%)
	4055-Energy Sales for Resale	(5,104,200)	(2,717,395)	(2,386,805)	(87.8%)
	4062-Billed WMS	(2,284,640)	(2,845,693)	561,053	19.7%
	4066-Billed NW	(2,199,030)	(2,597,603)	398,573	15.3%
	4068-Billed CN	(1,999,929)	(2,131,202)	131,273	6.2%
	4075-Billed-LV	(103,475)		(103,475)	
		(7,911,643)	(7,003,635)	(908,008)	(13.0%)
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	(7,911,643)	(7,003,635)		
	4082-Retail Services Revenues	(12,715)	(18,669)	5,954	31.9%
	4084-Service Transaction Requests (STR) Revenues	(1,664)	(76)	(1,588)	(2089.5%)
	4090-Electric Services Incidental to Energy Sales		(56,384)	56,384	100.0%
3100-Other Operating Revenues	4210-Rent from Electric Property	(310,078)	(180,000)	(130,078)	(72.3%)
	4215-Other Utility Operating Income	(2,641)		(2,641)	
	4220-Other Electric Revenues	(9,834)		(9,834)	
	4225-Late Payment Charges	(89,530)	(108,367)	18,837	17.4%
	4235-Miscellaneous Service Revenues	(159,654)	(59,390)	(100,264)	(168.8%)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.				
	4355-Gain on Disposition of Utility and Other Property				
	4375-Revenues from Non-Utility Operations		(429,823)	429,823	100.0%
	4380-Expenses of Non-Utility Operations	52,194	2,551	49,643	1946.0%
	4385-Non-Utility Rental Income		(119,049)	119,049	100.0%
	4390-Miscellaneous Non-Operating Income		(16)	16	100.0%
3200-Investment Income	4405-Interest and Dividend Income	(376,499)	(22,958)	(353,541)	(1539.9%)
3350-Power Supply Expenses	4705-Power Purchased	24,482,583	22,285,200	2,197,383	9.9%
	4708-Charges-WMS	2,284,640	2,782,476	(497,836)	(17.9%)
	4710-Cost of Power Adjustments		651,800	(651,800)	(100.0%)
	4714-Charges-NW	2,199,030	2,551,767	(352,737)	(13.8%)
	4716-Charges-CN	1,999,929	2,092,303	(92,374)	(4.4%)

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G5 Variance Analysis: Profit & Loss

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var \$	Var %
3500-Distribution Expenses - Operation	4750-Charges-LV	103,475		103,475	
	5010-Load Dispatching	2,449	245	2,204	899.6%
	5016-Distribution Station Equipment - Operation Labour	12,030	2,289	9,741	425.6%
	5017-Distribution Station Equipment - Operation Supplies and Expenses		2	(2)	(100.0%)
	5020-Overhead Distribution Lines and Feeders - Operation Labour	6,908	2,416	4,492	185.9%
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses		55	(55)	(100.0%)
	5035-Overhead Distribution Transformers-Operation	1,927	655	1,272	194.2%
	5040-Underground Distribution Lines and Feeders - Operation Labour	269,258	75,510	193,748	256.6%
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	16,428	3,251	13,177	405.3%
	5055-Underground Distribution Transformers - Operation	482	340	142	41.8%
	5065-Meter Expense	59,293	8,435	50,858	602.9%
	5070-Customer Premises - Operation Labour	713	343	370	107.9%
	5075-Customer Premises - Materials and Expenses		65	(65)	(100.0%)
	5085-Miscellaneous Distribution Expense	36,722	3,471	33,251	958.0%
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	44,337	30,847	13,490	43.7%
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	67,324	20,729	46,595	224.8%
	5114-Maintenance of Distribution Station Equipment	79,827	203,827	(124,000)	(60.8%)
	5120-Maintenance of Poles, Towers and Fixtures	92,575	30,298	62,277	205.5%
	5125-Maintenance of Overhead Conductors and Devices	282,089	70,555	211,534	299.8%
	5130-Maintenance of Overhead Services	91,758	75,980	15,778	20.8%
	5135-Overhead Distribution Lines and Feeders - Right of Way	193,255	165,118	28,137	17.0%

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G5 Variance Analysis: Profit & Loss

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var \$	Var %
	5145-Maintenance of Underground Conduit	64,914	5,590	59,324	1061.3%
	5150-Maintenance of Underground Conductors and Devices	55,227	35,519	19,708	55.5%
	5155-Maintenance of Underground Services	106,517	62,616	43,901	70.1%
	5160-Maintenance of Line Transformers	100,486	205,007	(104,521)	(51.0%)
	5175-Maintenance of Meters	6,164	39,639	(33,475)	(84.4%)
	5190-Water Heater Controls - Labour	95		95	
	5195-Maintenance of Other Installations on Customer Premises	141		141	
3650-Billing and Collecting	5305-Supervision	44,337	31,523	12,814	40.6%
	5310-Meter Reading Expense	261,687	265,424	(3,737)	(1.4%)
	5315-Customer Billing	399,891	394,641	5,250	1.3%
	5320-Collecting	426,995	341,055	85,940	25.2%
	5335-Bad Debt Expense	6,101	175,000	(168,899)	(96.5%)
	5340-Miscellaneous Customer Accounts Expenses	71	19	52	273.7%
3700-Community Relations	5410-Community Relations - Sundry		218	(218)	(100.0%)
	5415-Energy Conservation	14,494		14,494	
	5420-Community Safety Program	2,665	3,487	(822)	(23.6%)
	5425-Miscellaneous Customer Service and Informational Expenses	1,632	2,595	(963)	(37.1%)
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	89,008	75,787	13,221	17.4%
	5610-Management Salaries and Expenses	425,925	682,350	(256,425)	(37.6%)
	5615-General Administrative Salaries and Expenses	112,242	337,946	(225,704)	(66.8%)
	5620-Office Supplies and Expenses	223,506	256,426	(32,920)	(12.8%)
	5630-Outside Services Employed	240,708	368,602	(127,894)	(34.7%)
	5635-Property Insurance	66,825	125,693	(58,868)	(46.8%)
	5640-Injuries and Damages	584	19,254	(18,670)	(97.0%)
	5645-Employee Pensions and Benefits		26,954	(26,954)	(100.0%)
	5655-Regulatory Expenses	93,704	66,206	27,498	41.5%
	5660-General Advertising Expenses	15,187	9,541	5,646	59.2%
	5665-Miscellaneous General Expenses	88,673	343,740	(255,067)	(74.2%)
	5670-Rent	50,983	122,873	(71,890)	(58.5%)
	5675-Maintenance of General Plant	71,524	113,949	(42,425)	(37.2%)

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G5 Variance Analysis: Profit & Loss

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var \$	Var %
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	1,317,175	1,271,615	45,560	3.6%
	5725-Miscellaneous Amortization	21,150		21,150	
3900-Interest Expense	6005-Interest on Long Term Debt	568,662		568,662	
	6035-Other Interest Expense	81,827		81,827	
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	94,211	58,549	35,662	60.9%
4000-Income Taxes	6110-Income Taxes	1,245,000	65,000	1,180,000	1815.4%
	6115-Provision for Future Income Taxes	(360,824)		(360,824)	
4100-Extraordinary & Other Items	6205-Donations	2,973		2,973	
Net Income		1,624,229	1,028,417	595,812	57.9%

Variance Analysis on OM&A Costs

Acct	Description			
5010	Load Dispatching	\$	Var \$	Var %
	2006 EDR	245		
Actual	2006	2,449	2,204	899.60%
	2007	0	-2,449	-100%
Projected	2008	0	0	-
	2009	0	0	-

Load dispatching is line and feeder switching operations. Usually these are non-job specific and may be used for feeder balancing, and the like. At this time, feeder switching is being charged to the job being performed, such as substation maintenance. Costs that are allocated to this account are incurred for unanticipated or extraordinary events. Variances from year to year will be seen as need arises for feeder balancing.

Acct	Description	2006 EDR	2006	2007	2008	2009
5016	Distribution Station Equipment - Operations Labour	2,289	12,030	0		
5017	Distribution Station Equipment - Operations Supplies	2	150	374		
5114	Maintenance of Dist Station Equipment	203,827	79,827	(108,206)*	204,750	246,800
5110	Maintenance of Building & Fixtures - Dist Stations	20,729	67,324	5,562	25,900	0
		-----	-----	-----	-----	-----
Subtotal		226,847	159,331	(102,270)	231,650	246,800

* As explained below, WPI received a meter exit fee of \$263,400 from Hydro One. The expense in this account prior to the adjustment was \$155,194.

		\$	Var \$	Var %
	2006 EDR	226,847		
Actual	2006	159,331	-67,516	-29.8%
	2007	-102,270	-261,601	-264.2%
Projected	2008	231,650	333,920	426.5%
	2009	246,800	-15,150	-6.5%

Westario Power owns and maintains 28 substations. The substations undergo a complete maintenance once every four years, based on the advice of our substation contractor.

These costs, above, are shown grouped together, as they are representative of work performed to manage the one asset, namely substations and associated property. Maintenance of the distribution system substations is performed jointly by a certified substation contractor and Westario Power personnel.

Year to year maintenance varies as the repairs and maintenance performed is based on the contractor's assessment and recommendations. Costs can vary depending on the nature of the work involved and the number of substations maintained.

An outlier is the 2007 costs. In 2007 Westario received a payment from Hydro One Networks Inc. ('HONI') for meter exit fees, of approx \$263,400 which was applied to this account.

Acct	Description			
5020	OH Dist Lines and Feeders - Operations Labour	\$	Var \$	Var %
	2006 EDR	2,416		
Actual	2006	6,908	4,492	185.90%
	2007	20,083	13,175	190.70%
Projected	2008	0	-20,083	-100.00%
	2009	0	0	-

This account is for on-going and day-to-day maintenance of the overhead distribution lines and feeders. Events such as weather related failures or equipment failures are allocated here. Since these are unplanned events, the costs vary from time-to-time. In 2006 there were a number of severe wind storms that affected the service territory. In 2007 a significant and prolonged ice storm event was tracked on a separate job number to permit WPI to track the costs for reporting purposes, and the costs were ultimately charged to this account.

			Actual		Projected	
Acct	Description	2006 EDR	2006	2007	2008	2009
5035	OH Dist Transformers - Operations	665	1,927	866	0	
5055	UG Dist Transformers - Operations	340	482	0		
5160	Maintenance of Line Transformers	205,007	100,486	65,974	453,600	108,000
	Subtotal	206,012	102,895	68,867	453,600	108,000

		\$	Var \$	Var %
	2006 EDR	206,012		
Actual	2006	102,895	-103,117	-50.00%
	2007	68,867	-34,028	-33.10%
Projected	2008	453,600	384,733	558.70%
	2009	108,000	-345,600	-76.20%

1

2 These costs, above, are shown grouped together, as they are representative of work performed
 3 to manage overhead and underground line transformers. Events such as weather related
 4 failures or equipment failures are allocated here. Since these are unplanned events, the costs
 5 vary from year-to-year.

6

7 The 5160 account is used for transformer disposal and PCB oil disposal. Decommissioning of
 8 PCB transformers from several former utilities accounted for the costs. There were a significant
 9 number of PCB transformers that required disposal in 2004. The PCB disposal program
 10 continued though 2006, although to a lesser degree. The PCB disposal in 2007 was reduced
 11 and costs were subsequently reduced. The cost escalation in 2008 is attributed to the on-going
 12 PCB oil disposal and a planned field asset collection program. In 2008 this field asset collection
 13 program is focusing on pad mount transformers, as this task fulfills the regulatory requirement to
 14 inspect these devices. The field asset collection program is discussed at Exhibit 1, Tab 2,
 15 Schedule 1.

1

Acct	Description	2006 EDR	Actual		Projected	
			2006	2007	2008	2009
5040	UG Dist Lines and Feeders - Operations Labour	75,510	269,258	221,309	322,475	469,400
5045	UG Dist Lines & Feeders - Operations Supplies and Expenses	3,251	16,428	9,762	10,000	10,000
	Subtotal	78,761	285,686	231,071	332,475	479,400

2

		\$	Var \$	Var %
	2006 EDR	78,761		
Actual	2006	285,686	206,925	262.70%
	2007	231,071	-54,615	-19.10%
Projected	2008	332,475	101,404	43.90%
	2009	479,400	146,925	44.20%

3

4 In 2004 there was a prolonged labour disruption that affected cable locating. Consequently, the
 5 costs approved in the 2006 EDR process which were based on 2004 data were artificially low.

6

7 **Underground Locate Volumes:**

- 8 • 2004 to 2005: 2% increase
- 9 • 2005 to 2006: 11% increase
- 10 • 2006 to 2007: 16% increase

11 Westario Power does not have a dedicated cable locate crew. In 2009 Westario Power plans to
 12 contract out cable locating operations.

13

14 The cost escalation in 2009 in account 5040 is attributed to the on-going field asset collection
 15 program. In 2009 this field asset collection program is focusing on collecting the distribution
 16 assets, and this task fulfills the regulatory requirement to inspect these devices. The field asset
 17 collection program is discussed in Exhibit 2, Tab 2, Schedule 1.

Acct	Description	2006 EDR	Actual		Projected	
			2006	2007	2008	2009
5065	Meter Expenses	8,435	59,293	34,359	0	0
5175	Maintenance of Meters	39,639	6,164	13,128	309,175	95,000
	Subtotal	48,074	65,457	47,487	309,175	95,000

		\$	Var \$	Var %
	2006 EDR	48,074		
Actual	2006	65,457	17,383	36.20%
	2007	47,487	-17,970	-27.50%
Projected	2008	309,175	261,688	551.10%
	2009	95,000	-214,175	-69.30%

The above costs include revenue meters, wholesale meters for IESO compliance and interval metering for customers 50 kW or greater. IESO compliant meter work was required in 2005, 2006, and 2007, and some, but at a reduced amount, was required in 2004.

Meters were recertified in 2004, 2006 and 2007.

In 2007 a project to inspect all commercial services having instrument transformers for billing multiplier verification was undertaken. The installations have been inspected and the meter multipliers verified. This project will not be repeated in the near term.

In 2008, WPI will undertake to bring its expired meters up to date. The large expenditure is to accommodate the large number of meter change outs, and meter recertification costs. In 2008 WPI expects to clear the backlog of expired meters as directed by Measurement Canada. The 2009 costs, which are lower than 2008 will occur as the quantity of meters that expire in 2009 are fewer than those in 2008.

			Actual		Projected	
Acct	Description	2006 EDR	2006	2007	2008	2009
5070	Customer Premises - Operations Labour	343	713	0	0	0
5075	Customer Premises - materials and expense	65	0	312	0	1,000
	Subtotal	408	713	312	0	1,000

1

		\$	Var \$	Var %
	2006EDR	408		
Actual	2006	713	-305	-74.80%
	2007	312	-401	-56.20%
Projected	2008	0	-312	-100.00%
	2009	1,000	1,000	100.00%

2

3 These costs represent miscellaneous repairs on customer property as a result of Westario
 4 Power operations. Usually this is sod/surface repairs for secondary cable faults, tire ruts, etc. In
 5 the past, these expenses had not been budgeted. In 2009, WPI budgeted contracted services
 6 for miscellaneous lawn repairs.

7

			Actual		Projected	
Acct	Description	2006 EDR	2006	2007	2008	2009
5085	Misc Distribution Expense	3,471	36,460	32,460	0	0

8

		\$	Var \$	Var %
	2006EDR	3,471		
Actual	2006	36,460	32,989	950.40%
	2007	32,460	-4,000	-11.00%
Projected	2008	0	-32,460	-100.00%
	2009	0	0	0.00%

9

10 These costs included digital mapping Application Service Provider fees. In previous years,
 11 WPI's digital mapping vendor hosted our electronic maps on his network site. Westario Power
 12 acquired a server and computer hardware to manage the digital maps in-house. These ASP
 13 fees should not appear after 2007.

1

Acct	Description			
5105	Maintenance Supervision Engineering	\$	Var \$	Var %
Actual	2006 EDR	30,847		
	2006	44,337	13,490	43.73%
	2007	63,913	19,576	44.15%
Projected	2008	18,300	-45,613	-71.4%
	2009	16,775	-1,525	-8.3%

2

3 This account includes labour and expenses for general direction and supervision of the
 4 maintenance of the distribution plant that cannot be directly attributed to an individual
 5 maintenance account. Included in these costs for the time period 2006 EDR Approved to 2007
 6 are a portion of the costs paid by WPSI to WPI for the rental of the CIS system (which is utility
 7 owned property). WPSI then charged WPI for those same costs under the Master Services
 8 Agreement as evidenced in Exhibit 4, Tab 2, Schedule 4. There is a significant decrease in
 9 expenses from 2007 to 2008; as the Westario Power group of companies amalgamated on
 10 January 1, 2008; therefore the aforementioned costs will no longer occur.

11

Acct	Description			
5120	Maintenance of Poles, Towers and Fixtures	\$	Var \$	Var %
Actual	2006 EDR	30,298		
	2006	92,575	62,277	205.60%
	2007	72,718	-19,857	-21.50%
Projected	2008	58,920	-13,798	-19.00%
	2009	77,400	18,480	31.40%

12

13 This account is used to track costs for pole pulling after joint use attacher has transferred, for
 14 pole hole backfilling, and for miscellaneous supplies. For the 2006 EDR year there was a
 15 prolonged labour disruption that affected works. Consequently, the costs approved in the 2006
 16 EDR process which were based on 2004 data were artificially low.

17

18 Volume of work depends on speed at which the joint use attacher transfers, and whether WPI is
 19 provided notification. This work is also dependant on the volume of capital works and the
 20 locations.

1

Acct	Description			
5125	Maintenance of OH Conductors & Devices	\$	Var \$	Var %
	2006 EDR	70,555		
Actual	2006	282,089	211,534	299.80%
	2007	130,569	-151,520	-53.70%
Projected	2008	27,625	-102,944	-78.80%
	2009	131,200	103,575	374.90%

2

3 This account is used to track costs for the repair and maintenance of the overhead lines. In the
 4 2006 EDR Approved year there was a prolonged labour disruption that affected works.
 5 Consequently, the costs approved in the 2006 EDR process which were based on 2004 data
 6 were artificially low. In 2006 there were a number of severe wind storms that affected the
 7 service territory.

8

9 Events such as weather related failures or equipment failures are allocated here. Since these
 10 are events unplanned, the costs vary for time-to-time. The 2009 projected shows an increase
 11 as WPI attempted to more accurately budget this figure based on historical data

12

Acct	Description	2006 EDR	2006	2007	Projected	
					2008	2009
5130	Maintenance of OH Services	75,980	91,758	53,347	74,650	106,600
5155	Maintenance of UG Services	62,616	106,517	61,846	98,000	112,000
	Subtotal	138,596	198,275	115,193	172,650	218,600

13

		\$	Var \$	Var %
	2006EDR	138,596		
Actual	2006	198,275	59,679	43.10%
	2007	115,193	-83,082	-41.90%
Projected	2008	172,650	57,457	50.00%
	2009	218,600	45,950	26.60%

14

15 This group of accounts represents the maintenance of overhead services and underground
 16 secondary services. Costs attributed to this account include trouble calls, service upgrades,

and service isolations. Also included is work to repair secondary cable faults and associated material/hardware.

Nature of the work is cyclic and demand for the most part is customer driven. The budgets are based on historical counts. Of note, there has been a recent increase in the number of older secondary cable services failing.

Acct	Description			
5135	OH Dist Lines and Feeders - Right of Way	\$	Var \$	Var %
	2006 EDR	165,118		
Actual	2006	193,255	-28,137	-17.00%
	2007	156,758	-36,497	-18.90%
Projected	2008	230,250	73,492	46.90%
	2009	270,900	40,650	17.70%

This account is allocated for Tree Trimming and Line Clearing Operations. Every year Westario Power undertakes tree trimming and line clearing operations to manage vegetation growth near power lines. Typically WPI's service territories are trimmed on a three year schedule with approximately one-third of the services territories being trimmed each year. This improves reliability and provides for a level of public and worker safety.

The level of work is dependant on the growing season and particular instances, therefore causing variances year over year.

Acct	Description			
5145	Maintenance of UG Conduit	\$	Var \$	Var %
	2006 EDR	5,590		
Actual	2006	64,914	59,324	1061.30%
	2007	19,589	-45,325	-69.80%
Projected	2008	0	-19,589	-100.00%
	2009	0	0	0.00%

1
 2 This account represents miscellaneous duct and foundation repairs. These items are
 3 unplanned and are managed as the need arises.
 4

Acct	Description			
5150	Maintenance of UG Conductors and Devices	\$	Var \$	Var %
	2006 EDR	35,519		
Actual	2006	55,227	19,708	-55.48%
	2007	550	-54,677	99.0%
Projected	2008	4,600	4,050	736.36%
	2009	0	-4,600	-100.0%

5
 6 Repair and maintenance of high voltage underground cables and equipment.
 7
 8 The volume of work is dependant on the system trouble experienced. This varies from time to
 9 time and Westario Power responds to maintenance issues when devices cease to function.
 10 This account is for on-going and day-to-day maintenance of the underground conductors and
 11 devices. Since these are unplanned events, the costs vary from year-to-year.

1

Acct	Description			
5305	Supervision	\$	Var \$	Var %
	2006 EDR	31,523		
Actual	2006	44,337	12,814	40.6
	2007	63,913	19,576	44.20%
Projected	2008	18,300	-45,613	-71.40%
	2009	16,675	-1,525	-8.30%

2

3 This account represents the costs associated with the general supervision of customer
 4 accounting and collecting functions. Included in these costs for the 2006 EDR Approved year to
 5 2007 Actual, are a portion of the costs paid by WPSI to WPI for the rental of the CIS system
 6 (which is utility owned property). WPSI then charges WPI for those same costs under the
 7 Master Services Agreement. There is a significant decrease in expenses from 2007 to 2008; as
 8 the Westario Power group of companies amalgamated on January 1, 2008; those associated
 9 costs will no longer occur.

10

Acct	Description			
5310	Meter Reading Expense	\$	Var \$	Var %
	2006 EDR	265,424		
Actual	2006	261,687	-3,737	-1.40%
	2007	266,128	4,441	1.70%
Projected	2008	272,000	5,872	2.20%
	2009	272,000	0	0.00%

11

12 The above account records all meter reading costs as well as the monitoring of the Applicant's
 13 Wholesale Metering Points by a third party. Costs in this account are fairly static, with slight
 14 increases due to additional requests for final meter reads.

15

1

Acct	Description			
5315	Customer Billing	\$	Var \$	Var %
	2006 EDR	394,641		
Actual	2006	399,891	5,250	1.30%
	2007	348,180	-51,711	-12.90%
Projected	2008	371,035	22,855	6.60%
	2009	387,725	16,690	4.50%

2

3 Variances in Customer Billing are largely due to an average of 3% wage increases in each year.
 4 There was a significant decrease in 2007 largely due to decreased postage costs and
 5 maintenance costs relating to billing equipment. Increases in 2008 and 2009 are due to 3%
 6 salary increases and increases in postage and stationary costs.

7

Acct	Description			
5320	Collecting	\$	Var \$	Var %
	2006 EDR	341,055		
Actual	2006	426,995	85,940	25.20%
	2007	448,125	21,130	4.95%
Projected	2008	384,700	-63,425	-14.20%
	2009	416,400	31,700	8.20%

8

9 Variances in Collecting are partially due to an average of 3% wage increase in each year.
 10 Increases in costs from 2006 EDR Approved to 2006 Actual included wage increases,
 11 increases in the costs of delivering disconnect notifications and increased collection charges
 12 from WPI's third party collection agency. In 2007 there was an overlap of a contract employee
 13 with the Manager of Customer Service who was on a maternity leave, therefore additional costs
 14 were incurred. In mid 2007 a clerical position was also eliminated; which would result in a
 15 decrease in expenses for the year 2008. Increases in 2009 are due to a 3% salary increase,
 16 anticipated increases in the disconnect notification charges paid to a third party and increased
 17 charges paid to a third party collection agency. Anticipated increases paid to a third party for
 18 disconnection notification are as a result of the third party increasing the flat fee paid per
 19 notification delivery and the upward trend in disconnection notices issued. Anticipated
 20 increases in charges paid to a third party collection agency are as a result of increased costs for

Preparation Fees and Examination Costs. These are due to additional costs that the third party collection agency is incurring as they now require additional licensing from the Law Society of Upper Canada.

Acct	Description			
5335	Bad Debt Expense	\$	Var \$	Var %
	2006 EDR	175,000		
Actual	2006	6,101	-168,899	-96.50%
	2007	159,936	153,835	2521.50%
Projected	2008	100,000	-53,835	-53.8
	2009	150,000	50,000	50.00%

Westario Power's collection function involves ensuring appropriate follow-up and collection of unpaid accounts pursuant to its guidelines for managing overdue accounts. These guidelines meet all the requirements of the Distribution System Code and other OEB codes that impact collections and have been approved by Westario Power's senior management.

The decrease in 2006 Bad Debt expense is largely due to the Ontario Price Credit being applied to accounts that had previously been written off and amounts received from WPI's third party collection agency for accounts that had previously been written off. The increase in 2007 is in large part due to the increase in the provision for doubtful accounts. The provision was adjusted after a thorough review by management and by WPI's external auditor.

The amounts projected for 2008 and 2009 are a reflection of the trend that has been identified in collections and bad debt over the last 18 months.

1

Acct	Description	2006 EDR	Actual		Projected	
			2006	2007	2008	2009
5410	Community Relations – Sundry	218	0	185	13,470	20,500
5420	Community Safety Program	3,487	2,665	7,356	10,000	15,000
5425	Misc Customer Service and Informational Expenses	2,595	1,632	1,272	0	0
	Subtotal	6,300	4,297	8,813	23,470	35,500

2

		\$	Var \$	Var %
	2006EDR	6,300		
Actual	2006	4,297	-2,003	-31.80%
	2007	8,813	4,516	105.10%
Projected	2008	23,470	14,657	166.30%
	2009	35,500	12,030	51.30%

3

4 WPI is committed to having a presence in the communities that it serves, along with
 5 conservation and safety programs to school aged children. Variances in this account are as a
 6 result of increases in promotional materials and literature, as well as increased costs for a third
 7 party to provide school safety programs to the schools within our service territory. Safety
 8 programs offered to school aged children are on a three year rotation. There are more
 9 anticipated school visits by a third party contractor in 2009 than in 2008, thereby increasing
 10 costs.

11

Acct	Description			
5415	Energy Conservation	\$	Var \$	Var %
	2006 EDR	0		
Actual	2006	14,494	14,494	
	2007	476,540	462,046	3187.80%
Projected	2008	0	-476,540	-100.00%
	2009	0	0	0.00%

12

13 The expenses in this account are for programs related to Conservation and Demand
 14 Management under the Third Tranche funding. There are no funds allocated for these
 15 programs in the future.

16

In 2007, a total of twenty (20) different projects were undertaken to meet the requirements of the CD&M Plan approved by the Board. The programs provided either technology or information to over 23,000 individuals. In addition to these numbers, would be the customers who either heard the information provided in the radio advertising or noted the conservation message in newspaper advertising related to the programs.

The overall Total Resource Cost (TRC) Benefit for the 20 programs was \$644,000 with a Net TRC value of \$247,425. TRC is the deferred cost to the electrical system as a result of taking action to conserve. Over the lifetime of the technology provided through the programs it is estimated that 10,722,820 kWh will be saved.

Acct	Description			
5605	Executive Salaries and Expenses	\$	Var \$	Var %
	2006 EDR	75,787		
Actual	2006	89,008	13,224	17.50%
	2007	96,578	7,570	8.50%
Projected	2008	128,125	31,547	32.70%
	2009	130,000	1,875	1.50%

Executive Salaries and Expenses include the salaries and expenses of WPI's board of directors. Prior to the amalgamation of Westario Power Inc. with Westario Power Holdings Inc., and Westario Power Services Inc. the Board of Directors' costs were split under the Master Services' Agreements as found in Exhibit 4, Tab 2, Schedule 4. Effective January 1, 2008 as there is only one sole company, all costs relating to the Board of Directors are allocated to WPI. There is a slight increase in the 2009 test year for salary increases and projected increases to expense reimbursements.

1

Acct	Description			
5610	Management Salaries and Expenses	\$	Var \$	Var %
	2006 EDR	682,350		
Actual	2006	425,925	-256,425	-37.60%
	2007	427,358	1,433	3.40%
Projected	2008	631,100	203,742	47.70%
	2009	689,400	58,300	11.00%

2

3 Included in the above are salaries and related expenses of management. Prior to the
 4 amalgamation of Westario Power Inc. with Westario Power Holdings Inc., and Westario Power
 5 Services Inc.; management salaries and related expenses were split between WPI and
 6 Westario Power Services Inc. ('Servco') under the Master Services' Agreements ('MSA') as
 7 found in Exhibit 4, Tab 2, Schedule 4. Effective January 1, 2008 as there is only one company,
 8 all costs relating to management salaries and expenses are allocated to WPI. In the 2006 EDR
 9 Approved; all costs related to management salaries and expenses were transferred from Servco
 10 to WPI. In 2006 under the MSA only 65% of costs were transferred between companies, with
 11 the balance of the expenses remaining in Servco. In December 2007 a management position
 12 that had been vacant since early 2006 was filled. The increase from 2008 Bridge to 2009 Test
 13 can be accounted for by an average of a 3% salary increase, a reduction in the amount of
 14 management salaries recovered through burdens, and additional expenses incurred for training
 15 and professional development.

16

Acct	Description			
5615	General Admin Salaries and Expenses	\$	Var \$	Var %
	2006 EDR	337,946		
Actual	2006	112,242	-225,704	-66.80%
	2007	118,513	6,271	6.60%
Projected	2008	145,150	26,637	22.50%
	2009	143,300	-1,850	-1.30%

17

18 Prior to the amalgamation of Westario Power Inc. with Westario Power Holdings Inc., and
 19 Westario Power Services Inc.; general admin salaries and expenses were split between WPI
 20 and Westario Power Services Inc. ('Servco') under the Master Services' Agreements ('MSA') as

found in Exhibit 4, Tab 2, Schedule 4. Effective January 1, 2008 as there is only one company, all costs relating to general administrative salaries and expenses are allocated to WPI. In the 2006 EDR Approved; 100% of costs related to general administrative salaries and expenses was transferred from Servo to WPI. In 2006 under the MSA only 65% of costs were transferred between companies, with the balance of the expenses remaining in Servco. The increase from 2007 to 2008 can be attributed to the fact that an additional finance clerk was hired mid 2007; therefore, the full salary would be reflected in 2008.

Acct	Description			
5620	Office Supplies and Expenses	\$	Var \$	Var %
	2006 EDR	368,602		
Actual	2006	240,708	-127,894	-34.70%
	2007	271,947	31,239	12.90%
Projected	2008	326,125	54,178	19.90%
	2009	368,650	45,525	13.00%

Prior to the amalgamation of Westario Power Inc. with Westario Power Holdings Inc., and Westario Power Services Inc.; office supplies and expenses were split between WPI and Westario Power Services Inc. ('Servco') under the Master Services' Agreements ('MSA') as found in Exhibit 4, Tab 2, Schedule 4. Effective January 1, 2008 as there is only one company, all costs relating to office supplies and expenses are allocated to WPI. In the 2006 EDR Approved; 100% of costs related to office supplies and expenses was transferred from Servo to WPI. In 2006 under the MSA only 65% of costs were transferred between companies, with the balance of the expenses remaining in Servco. Increases to this account have been as a result of steady increases in costs of office supplies, and increasing costs related to licensing and support for Information Technology.

1

Acct	Description			
5630	Outside Services - Employed	\$	Var \$	Var %
	2006 EDR	368,602		
Actual	2006	240,708	-127,894	-34.70%
	2007	353,621	112,913	46.90%
Projected	2008	311,490	-42,131	-11.90%
	2009	178,500	-132,990	-42.70%

2

3 This account relates to costs for outside services including but not limited to accounting, legal,
 4 and regulatory. Prior to the amalgamation of Westario Power Inc. with Westario Power
 5 Holdings Inc., and Westario Power Services Inc.; outside services were split between WPI and
 6 Westario Power Services Inc. ('Servco') under the Master Services' Agreements ('MSA') as
 7 found in Exhibit 4, Tab 2, Schedule 4. Effective January 1, 2008 as there is only one company,
 8 all costs relating to outside services are allocated to WPI. In the 2006 EDR Approved; 100% of
 9 costs related to outside services – employed were transferred from Servo to WPI. In 2006
 10 under the MSA only 65% of costs were transferred between companies, with the balance of the
 11 expenses remaining in Servco. There were increased costs in 2007 related to a number of
 12 factors including pay equity, collective agreement contract negotiations, and costs associated
 13 with the amalgamation of the Westario Power Group of Companies. There is a decrease from
 14 2008 bridge to 2009 test years as there are funds allocated in 2008 for a potential merger or
 15 amalgamation prior to the expiration of the Transfer Tax Holiday on October 17, 2008.

16

Acct	Description			
5635	Property Insurance	\$	Var \$	Var %
	2006 EDR	125,693		
Actual	2006	66,825	-56,868	-45.20%
	2007	89,910	23,085	34.60%
Projected	2008	97,125	7,215	8.00%
	2009	101,125	4,000	4.10%

17

18 Prior to the amalgamation of Westario Power Inc. with Westario Power Holdings Inc., and
 19 Westario Power Services Inc.; property insurance costs were split between WPI and Westario
 20 Power Services Inc. ('Servco') under the Master Services' Agreements ('MSA') as found in

Exhibit 4, Tab 2, Schedule 4. Effective January 1, 2008 as there is only one company, all costs relating to property insurance are allocated to WPI. In the 2006 EDR Approved; 100% of costs related to property insurance was transferred from Servo to WPI. In 2006 under the MSA only 65% of costs were transferred between companies, with the balance of the expenses remaining in Servco. Insurance costs have increased based on WPI's claim history and the insurance company's assessment of the Applicant's risk factor.

Acct	Description			
5645	Employee Pensions and Benefits	\$	Var \$	Var %
	2006 EDR	26,954		
Actual	2006	0	-26,954	-100.00%
	2007	0	0	
Projected	2008	0	0	
	2009	0	0	

WPI is a member of the OMERS pension plan. The amount approved in the 2006 EDR is the differential between the 2004 and 2005 OMERS amounts. This account is no longer used as all employer contributions for employees are included in a 'payroll burden' and allocated to the appropriate expense account.

Acct	Description			
5655	Regulatory Expenses	\$	Var \$	Var %
	2006 EDR	66,206		
Actual	2006	93,704	27,498	41.50%
	2007	64,660	-29,044	-31.00%
Projected	2008	59,900	4,760	7.40%
	2009	140,000	80,100	133.70%

The increase from the 2006 EDR approved to the 2006 actual can be attributed to the additional costs incurred for the 2006 EDR and Recovery of Regulatory Assets process. Included in this account are OEB Assessment amounts and cost rewards for Intervenors. The applicant has estimated the total cost for this 2009 Cost of Service Application to be \$240,000. Included in this account is one-third of the above cost or \$80,000 that would be apportioned to the 2009 test year.

1

5660	General Advertising Expenses	\$	Var \$	Var %
	2006 EDR	9,541		
Actual	2006	15,187	-5,646	-86.30%
	2007	17,826	2,639	17.40%
Projected	2008	11,900	-5,926	-33.20%
	2009	3,000	-8,900	-74.80%

2

3 There are minimal dollar amount variations in this account. Although a dollar amount is
 4 provided for the 2009 test year, it is based on known advertising amounts. Often this account
 5 will fluctuate based on number of outage notifications that are provided to WPI's customers.

6

5665	Miscellaneous General Expenses	\$	Var \$	Var %
	2006 EDR	343,740		
Actual	2006	88,673	-255,067	-74.20%
	2007	127,827	39,154	44.20%
Projected	2008	36,600	-91,227	-71.40%
	2009	33,550	-3,050	-9.10%

7

8 For the time period of 2006 EDR Approved to 2007 Actual, included in this account are rental
 9 fees paid by Servco to WPI for utility owed equipment. The expense that Servco incurred was
 10 then transferred from Servco to WPI under the MSA as found in Exhibit 4, Tab 2, Schedule 4.
 11 Because the Westario Power Group of Companies amalgamated on January 1, 2008; these
 12 costs will no longer be incurred. Costs in this account for the 2008 Bridge Year and 2009 Test
 13 Year are industry-related membership fees.

1

5670	Rent	\$	Var \$	Var %
	2006 EDR	122,873		
Actual	2006	50,983	-71,890	-58.50%
	2007	221,250	170,267	333.90%
Projected	2008	0	-221,250	-100.00%
	2009	0	0	

2

3 Included in this account are rents paid for the operational facilities. Prior to the amalgamation of
 4 Westario Power Inc. with Westario Power Holdings Inc. and Westario Power Services Inc.; rent
 5 was split between WPI and Westario Power Services Inc. ('Servco') under the Master Services'
 6 Agreements ('MSA') as found in Exhibit 4, Tab 2, Schedule 4. In the 2006 EDR Approved;
 7 100% of costs related to rent was transferred from Servo to WPI. In 2006 under the MSA only
 8 65% of costs were transferred between companies, with the balance of the expenses remaining
 9 in Servco. At the time of the 2006 EDR approved amount Servco was leasing four facilities, but
 10 had reduced the number of facilities it was renting in 2006 to two. In 2007, Servco rented two
 11 facilities from January to July; and one facility from June to December. In 2007, Servo rented
 12 from WPI utility owned property (the operations facility). The expense that Servo incurred was
 13 then transferred from Servo to WPI under the MSA as found in Exhibit 4, Tab 2, Schedule 4.
 14 Because the Westario Power Group of Companies amalgamated on January 1, 2008; these
 15 costs will no longer be incurred.

16

5675	Maintenance of General Plant	\$	Var \$	Var %
	2006 EDR	113,949		
Actual	2006	71,524	-42,425	-37.20%
	2007	117,873	46,349	64.80%
Projected	2008	100,750	-17,123	-14.50%
	2009	98,325	-2,425	2.40%

17

18 Prior to the amalgamation of Westario Power Inc. with Westario Power Holdings Inc., and
 19 Westario Power Services Inc.; maintenance of general plant was split between WPI and
 20 Westario Power Services Inc. ('Servco') under the Master Services' Agreements ('MSA') as
 21 found in Exhibit 4, Tab 2, Schedule 4. Effective January 1, 2008 as there is only one company

- 1 WPI, all costs relating to maintenance of general plant is allocated to WPI. In the 2006 EDR
- 2 Approved; 100% of costs related to maintenance of general plant was transferred from Servo to
- 3 WPI. In 2006 under the MSA only 65% of costs were transferred between companies, with the
- 4 balance of the expenses remaining in Servco. Costs have been reduced due to the fact that
- 5 WPI currently operates out of one facility as opposed to a number of locations.

Materiality Analysis on OM&A Costs

The materiality thresholds for OM&A cost as specified in the Board filing requirements are presented below.

	2009 Test	2008 Bridge	2007 Actual	2006 Actual	2006 EDR Approved
Total Distribution Expenses	\$6,629,571	\$6,086,828	\$5,639,047	\$5,586,300	\$6,136,249
Percent	1%	1%	1%	1%	1%
Threshold	\$66,296	\$60,868	\$56,390	\$55,863	\$61,362

The remainder of this Schedule discusses variances in specific OM&A accounts that exceed the thresholds.

2009 Bridge Year vs. 2008 Test Year

	2009 Bridge	2008 Test	Var \$	Var %
5040-Underground Distribution Lines and Feeders - Operation Labour	469,400	322,475	146,925	45.6%

The number of underground cable locate requests have been dramatically increasing since 2005 as the various telephone companies in our service territories have been installing extensive fibre optic cable networks throughout the communities that WPI serves. This has resulted in increased cable location costs.

Underground Locate Volumes

2004 to 2005: 2% increase

2005 to 2006: 11% increase

2006 to 2007: 16% increase

Westario Power does not have a dedicated cable locate crew. In 2009 the Company plans to contract out cable locating operations.

1 Additionally, the Company will be continuing with the second year of its three year program to
2 collect data on its distribution system assets. This project will provide the data needed to
3 develop an effective asset management/replacement program as well as meeting the regulatory
4 requirement to inspect the distribution system.

	2009 Bridge	2008 Test	Var \$	Var %
5125-Maintenance of Overhead Conductors and Devices	131,200	27,625	103,575	374.9%

6
7 This account is for on-going and day-to-day maintenance of the overhead conductors and
8 devices. Events such as weather related failures or equipment failures are allocated here.
9 Since these are events unplanned, the costs vary for year-to-year. The 2009 projection shows
10 an increase as a more accurate budget based on historical experience.

	2009 Bridge	2008 Test	Var \$	Var %
5160-Maintenance of Line Transformers	108,000	453,600	(345,600)	(76.2%)

12
13 This account is used for transformer and PCB oil disposal. While the Company's distribution
14 system does not contain any transformers known to be labeled by the manufacturer as
15 containing PCB oil, experience in the industry has shown that a significant number of
16 transformers manufactured prior to 1981 have some level of PCB oil. These transformers are
17 identified through the Company's oil testing procedure when transformers are removed from
18 service.

19 The number of transformers found to contain PCB oil in any given year is dependent on the
20 number of transformers that fail and/or are replaced in conjunction with capital pole line re-
21 construction projects.

22
23 In 2008 the Company started a three program to collect data on the installed distribution system
24 assets. The data inherited from the previous municipal utilities was woefully inadequate to form
25 the basis of an asset management system. In 2009 the field data collection costs are captured
26 in Account 5160.

1

	2009 Bridge	2008 Test	Var \$	Var %
5175-Maintenance of Meters	95,000	309,175	(214,175)	(69.3%)

2

3 This account captures the cost of re-certifying revenue meters to Measurement Canada's
 4 standards.

5

6 The 2008 Bridge year and 2009 Test year is to continue the planned meter changes for
 7 Measurement Canada compliance on poly-phase demand meters. There are more planned
 8 meter re-certifications in 2008 than in 2009, creating the decrease as shown above.

9

	2009 Bridge	2008 Test	Var \$	Var %
5630-Outside Services Employed	178,500	311,490	(132,990)	(42.7%)

10

11

12 The projected decrease in outside services for the 2009 bridge year is a result of funds being
 13 allocated in the 2008 test year for a potential merger or acquisition prior to the expiration of the
 14 Transfer Tax Holiday on October 17, 2008.

15

16 **2008 Test Year vs. 2007 Actual**

17

	2008 Test	2007 Actual	Var \$	Var %
5040-Underground Distribution Lines and Feeders - Operation Labour	322,475	221,309	101,166	45.7%

18

19 The number of underground cable locate requests have been dramatically increasing since
 20 2005 as the various telephone companies in our service territories have been installing
 21 extensive fibre optic cable networks throughout the communities the Company serves. This has
 22 resulted in increased cable location costs.

23

Underground Locate Volumes

2004 to 2005: 2% increase
 2005 to 2006: 11% increase
 2006 to 2007: 16% increase

Westario Power does not have a dedicated cable locate crew. In 2008 WPI continues to use its' own resources for cable locating operations.

	2008 Test	2007 Actual	Var \$	Var %
5114-Maintenance of Distribution Station Equipment	204,750	(108,206)	312,956	289.2%

An outlier is the 2007 costs. In 2007 Westario received a payment from Hydro One for meter exit fees, of approx \$263,400; which was applied to this account. The 'normalized' costs for the 2007 year were \$155,914, therefore creating a variance of \$49,556 (31.78%).

Westario Power owns and maintains 28 substations. The substations undergo a complete maintenance once every four years, based on the advice of our substation contractor.

Maintenance of the distribution system substations is performed jointly by a certified substation contractor and Westario Power personnel.

Year to year maintenance varies as the repairs and maintenance performed is based on the contractor's assessment and recommendations. Costs can vary depending on the nature of the work involved and the number of substations maintained.

	2008 Test	2007 Actual	Var \$	Var %
5125-Maintenance of Overhead Conductors and Devices	27,625	130,569	(102,944)	(78.8%)

This account is for on-going and day-to-day maintenance of the overhead conductors and devices. Events such as weather related failures or equipment failures are allocated here. Since these events are unplanned, the costs vary for year-to-year.

1

	2008 Test	2007 Actual	Var \$	Var %
5135-Overhead Distribution Lines and Feeders - Right of Way	230,250	156,758	73,492	46.9%

2

3 This account is allocated for Tree Trimming and Line Clearing Operations. Every year Westario
 4 Power undertakes tree trimming and line clearing operations to manage vegetation growth near
 5 power lines. Typically tree trimming is carried out over a three year cycle with one-third of the
 6 system trimmed each year. The improved reliability and provides for a level public and worker
 7 safety.

8

9 The level of work is dependant on the growing season and particular instances, therefore
 10 causing variances year over year.

11

	2008 Test	2007 Actual	Var \$	Var %
5160-Maintenance of Line Transformers	453,600	65,974	387,626	587.5%

12

13 This account is used for transformer and PCB oil disposal. While the Company's distribution
 14 system does not contain any transformers known to be labeled by the manufacturer as
 15 containing PCB oil, experience in the industry has shown that a significant number of
 16 transformers manufactured prior to 1981 have some level of PCB oil. These transformers are
 17 identified through the Company's oil testing procedure when transformers are removed from
 18 service. The number of transformers found to contain PCB oil in any given year is dependent
 19 on the number of transformers that fail and/or are replaced in conjunction with capital pole line
 20 re-construction projects.

21

22 As stated in Exhibit 2, Tab 3, Schedule 1, in 2008 the Company started a three program to
 23 collect data on the installed distribution system assets. The data inherited from the previous
 24 municipal utilities was woefully inadequate to form the basis of an asset management system.
 25 The field data collection costs are captured in Account 5160 explaining the increase from 2007.

26

	2008 Test	2007 Actual	Var \$	Var %
5175-Maintenance of Meters	309,175	13,128	296,047	2255.1%

1

2 In 2007 a project to inspect all commercial services having instrument transformers for billing
 3 multiplier verification was undertaken. The installations have been inspected and the meter
 4 multipliers verified. This project will not be repeated in the near term.

5

6 In 2008 and 2009 the Company has an atypically high number of poly-phase demand meters
 7 that need to be changed to comply with Measurement Canada. In 2008, WPI will replace
 8 approximately 400 poly-phase meters.

9

	2008 Test	2007 Actual	Var \$	Var %
5320-Collecting	384,700	448,125	(63,425)	(14.2%)

10

11 In 2007 there was an overlap of a contract employee with the Manager of Customer Services
 12 who was on maternity leave, therefore causing additional costs in 2007. In mid-2007 a clerical
 13 position was eliminated; which would result in a decrease in expenses for the year 2008.

14

	2008 Test	2007 Actual	Var \$	Var %
5415-Energy Conservation		476,540	(476,540)	(100.0%)

15

16 Expenses relating to this account are as a result of Third Tranche spending on Conservation
 17 and Demand Management programs. All funds were to be allocated by December 31, 2007.
 18 There is no anticipated spending in 2008.

19

	2008 Test	2007 Actual	Var \$	Var %
5610-Management Salaries and Expenses	631,100	427,358	203,742	47.7%

In 2007 WPI had a Master Services agreement with its' affiliate Westario Power Services Inc. ('WPSI'). Under the MSA; WPSI provides certain operating, maintenance, administrative and capital construction services, including certain labour related expenses. The total cost to WPI charged from WPSI is calculated as follows:

OM&A Costs shall be paid monthly in an amount calculated as follows:

$$\frac{x + y - w + v}{12} = z$$

Where:

v = annual actuarial costs of employees' future benefits

w = base income of Wiresco transferred to Servco based on 1999 consolidated rate application of the predecessor municipal electric utilities of Wiresco

x = the aggregate of all of the operations, management and administration costs set out in the 1999 consolidated rate application of the predecessor municipal electric utilities of Wiresco

y = the depreciation amount in the budget of Servco for the applicable fiscal year

z = the monthly payment by Wiresco to Servco in respect of OM&A Costs

Provided that at the end of the applicable fiscal year an adjustment shall be made to reflect actual (as opposed to budgeted) depreciation applicable to Servco.

In 2007; the actual costs in WPSI exceeded the amounts to be transferred as calculated above, and therefore not all related management costs were charged by WPSI to WPI. As the Westario Power Group of Companies has amalgamated in 2008, the 2008 test year is representative of all management salaries and related expenses. In addition, in December 2007 a management vacancy was filled that had been vacant since early 2006. The 2008 test year also includes an average 3% salary increase for management and increased costs for training and professional development.

	2008 Test	2007 Actual	Var \$	Var %
5665-Miscellaneous General Expenses	36,600	127,827	(91,227)	(71.4%)

1

2 Included in this account are rental fees paid by affiliate WPSI to WPI for utility owned
 3 equipment, subsequently charged to WPI under the MSA. There is no net cost to the utility as
 4 WPI has included the income received in 4210 – Rent from Electric Property. Because the
 5 Westario Power Group of companies amalgamated on January 1, 2008; these costs will no
 6 longer be incurred. The costs projected for 2008 include industry related membership fees.

7

	2008 Test	2007 Actual	Var \$	Var %
5670-Rent		221,250	(221,250)	(100.0%)

8

9 Included in this account are amounts for rents paid for the operational facilities. In 2007 WPI
 10 had a Master Services agreement with its' affiliate Westario Power Services Inc. ('WPSI').
 11 Under the MSA; WPSI provides certain operating, maintenance, administrative and capital
 12 construction services, including certain labour related expenses. In 2007 WPSI paid rent for
 13 three operational facilities; Hanover, Kincardine and Walkerton (which is utility owned property).
 14 The amount incurred above is the amount that was charged by WPSI to WPI under the MSA as
 15 found in Exhibit 4, Tab 2, Schedule 4. WPI charged rent to WPSI in the amount of \$172,110
 16 (which is included in account 4210 – Rent from Electric Property); therefore the net rental
 17 expense to WPI is \$49,140. Because the Westario Power Group of companies amalgamated
 18 on January 1, 2008; these costs will no longer be incurred.

19

	2008 Test	2007 Actual	Var \$	Var %
6105-Taxes Other Than Income Taxes	50,600	118,449	(67,849)	(57.3%)

20

21 The decrease in the 2008 test year vs. the 2007 actual is that for the purposes of this
 22 application, capital taxes have been included in Account '6110-Income Taxes'. 2007 Actual
 23 includes capital tax of approximately \$52,000.

2007 Actual vs. 2006 Actual

	2007 Actual	2006 Actual	Var \$	Var %
5110-Maintenance of Buildings and Fixtures - Distribution Stations	5,562	67,324	(61,762)	(91.7%)

In 2006; all costs related to station work performed by a third party contractor was included in the above account. In 2007, WPI felt it more appropriate to include those amounts in Account 5114-Maintenance of Distribution Station Equipment. In 2007 approximately \$38,000 of works that in the past had been allocated to 5110, were more appropriately allocated to 5114.

	2007 Actual	2006 Actual	Var \$	Var %
5114-Maintenance of Distribution Station Equipment	(108,206)	79,827	(188,033)	(235.6%)

An outlier is the 2007 costs. In 2007 Westario received a payment from Hydro One for meter exit fees, of approx \$263,400; which was applied to this account. The 'normalized' costs for the 2007 year were \$155,914, therefore creating a variance of \$76,087 (95,31%).

Westario Power owns and maintains 28 substations. The substations undergo a complete maintenance once every four years, based on the advice of our substation contractor.

Maintenance of the distribution system substations is performed jointly by a certified substation contractor and Westario Power personnel.

Year to year maintenance varies as the repairs and maintenance performed is based on the contractor's assessment and recommendations. Costs can vary depending on the nature of the work involved and the number of substations maintained.

1

	2007 Actual	2006 Actual	Var \$	Var %
5125-Maintenance of Overhead Conductors and Devices	130,569	282,089	(151,520)	(53.7%)

2

3 This account is for on-going and day-to-day maintenance of the overhead conductors and
 4 devices. Events such as weather related failures or equipment failures are allocated here.
 5 Since these events are unplanned, the costs vary from year-to-year.

6

7 In 2006 there were a number of severe wind storms that affected the service territory. In 2007 a
 8 significant and prolonged ice storm event was tracked on a separate job number to permit us to
 9 record the costs for reporting purposes, and the costs were ultimately charged to this account.

10

	2007 Actual	2006 Actual	Var \$	Var %
5335-Bad Debt Expense	159,936	6,101	153,835	2521.5%

11

12 Bad debt is the portion of receivables that can no longer be collected, typically from accounts
 13 receivable or loans. Bad debt is considered an expense. There are two methods to account for
 14 bad debt:

15

16 **Direct write off method:** A receivable which is not considered collectible is charged directly to
 17 the income statement.

18

19 **Allowance method:** An estimate is made at the end of each fiscal year of the amount of bad
 20 debt. This is then accumulated in a provision which is then used to reduce specific receivable
 21 accounts as and when necessary.

22

23 As much as WPI tries to avoid them, bad debt write-offs are a part of doing business on credit
 24 terms. Financial controls that set out the process for identifying, documenting, and approving
 25 bad debt write-offs have been put in place through an internal Bad Debt Policy.

26

Overdue Accounts Turned Over to Third Parties for Collection

WPI's Customer Service Department follows its' own internal Bad Debt Policy for collection of accounts. As a rule, bad debt accounts are aggressively pursued internally. Accounts are turned over to a third party collection company approximately 30 days after delinquency of the final bill.

When Overdue Accounts are Written Off as Bad Debt

The Manager of Customer Service completes periodic reviews of inactive accounts and write offs. Inactive accounts of 3 years or more are written off.

How are Security Deposits Used to Reduce Bad Debts Expense

Bad debt write offs can be reduced by requesting deposits or equivalent security from customers who cannot demonstrate satisfactory payment records or otherwise reasonably assure payment of future charges. Security deposits are requested in compliance with the Distribution System Code. Unreturned security deposits are applied to consumer's final bills. Therefore, account balances outstanding on final billed accounts are net of security deposits.

Financial Controls

Financial controls stipulate that the larger the amount of the write-off, the higher up the chain of command it has to go to be approved. In WPI's practice , the Manger of Customer Service approves all write-offs. The Manager of Customer Service is the only employee with access to the transaction code within the CIS system for conducting customer write-offs. For accounting purposes, the GST/DRC is itemized on the report. Accounts outstanding, with a value of \$1,000 for Residential customers and \$5,000 for General Service Customers, for more than 90 days, will be brought to the attention of the Chief Financial Officer for review.

Permission to Sue

Permissions to Sue will be forwarded to the third party collection agency when the outstanding balance is in excess of \$350 and only if there is a guarantee of garnishment, execution of lien against land or hold on bank account(s).

Based on the practices as documented above, there was a substantial increase to the bad debt expense as a result of adjusting the provision for uncollectible accounts. 2006 is somewhat an outlier based on the fact that the Ontario Price Credit received in December 2005 was applied to inactive accounts, thereby reducing the total amount of the write offs, also, amounts were received from WPI's third party collection agency for accounts that had previously been written off.

	2007 Actual	2006 Actual	Var \$	Var %
5415-Energy Conservation	476,540	14,494	462,046	3187.8%

The large increase in Energy Conservation costs were as a result of spending Third Tranche funds for Conservation and Demand Management programs. These programs are not ongoing, and there are no anticipated future costs.

	2007 Actual	2006 Actual	Var \$	Var %
5630-Outside Services Employed	353,621	240,708	112,913	46.9%

Included in this account are amounts for outside services including but not limited to accounting, legal and regulatory. In 2007 WPI had a Master Services Agreement with its' affiliate Westario Power Services Inc. ('WPSI'). Under the MSA; WPSI provides certain operating, maintenance, administrative and capital construction services, including certain labour related expenses. In 2006, the expenses incurred by WPSI exceeded the amount allowed to be charged to WPI; therefore not all costs relating to outside services were charged in 2006. In addition, the increase in 2007 can be attributed to additional costs for pay equity, collective agreement contract negotiations and costs associated with the amalgamation of the Westario Power Group of Companies.

	2007 Actual	2006 Actual	Var \$	Var %
5670-Rent	221,250	50,983	170,267	334.0%

Included in this account are amounts for rents paid for the operational facilities. In 2007 WPI had a Master Services agreement with its' affiliate Westario Power Services Inc. ('WPSI'). Under the MSA; WPSI provides certain operating, maintenance, administrative and capital construction services, including certain labour related expenses. In 2007 WPSI paid rent for three operational facilities; Hanover, Kincardine and Walkerton (the Walkerton facility is utility owned property). The amount incurred above is the amount that was charged by WPSI to WPI under the MSA as found in Exhibit 4, Tab 2, Schedule 4. WPI charged rent to WPSI in the amount of \$172,110 (which is included in account 4210 – Rent from Electric Property); therefore the net rent expense to WPI in 2007 is \$49,140; therefore the net cost to WPI between 2007 and 2006 is marginal.

2006 Actual vs. 2006 EDR Approved

	2006 Actual	2006 EDR Approved	Var \$	Var %
5040-Underground Distribution Lines and Feeders - Operation Labour	269,258	75,510	193,748	256.6%

The number of underground cable locate requests have been dramatically increasing since 2005 as the various telephone companies in our service territories have been installing extensive fibre optic cable networks throughout the communities the Company serves. This has resulted in increased cable location costs. Westario Power does not have a dedicated cable locate crew.

Underground Locate Volumes

2004 to 2005: 2% increase

2005 to 2006: 11% increase

	2006 Actual	2006 EDR Approved	Var \$	Var %
5114-Maintenance of Distribution Station Equipment	79,827	203,827	(124,000)	(60.8%)

Westario Power owns and maintains 28 substations. The substations undergo a complete maintenance once every four years, based on the advice of our substation contractor.

Maintenance of the distribution system substations is performed jointly by a certified substation contractor and Westario Power personnel.

Year to year maintenance varies as the repairs and maintenance performed is based on the contractor's assessment and recommendations. Costs can vary depending on the nature of the work involved and the number of substations maintained.

Maintenance costs were lower than expected in 2006.

	2006 Actual	2006 EDR Approved	Var \$	Var %
5120-Maintenance of Poles, Towers and Fixtures	92,575	30,298	62,277	205.5%

This account is used to track costs for pole removal after joint use attachments have been transferred to new poles, for pole hole backfilling, and for miscellaneous supplies. For the 2006 EDR year there was a prolonged labour disruption that affected works.

Volume of work depends on speed at which the joint use attached transfers, and whether we are provided notification. This work is also dependant on the volume of capital works and the locations.

	2006 Actual	2006 EDR Approved	Var \$	Var %
5125-Maintenance of Overhead Conductors and Devices	282,089	70,555	211,534	299.8%

This account is for on-going and day-to-day maintenance of the overhead conductors and devices. Events such as weather related failures or equipment failures are allocated here. Since these are events unplanned, the costs vary for year-to-year.

In 2006 there were a number of severe wind storms that affected the service territory.

	2006 Actual	2006 EDR Approved	Var \$	Var %
5160-Maintenance of Line Transformers	100,486	205,007	(104,521)	(51.0%)

This account is used for transformer and PCB oil disposal. While the Company's distribution system does not contain any transformers known to be labeled by the manufacturer as containing PCB oil, experience in the industry has shown that a significant number of transformers manufactured prior to 1981 have some level of PCB oil. These transformers are identified through the Company's oil testing procedure when transformers are removed from service. The number of transformers found to contain PCB oil in any given year is dependent on the number of transformers that fail and/or are replaced in conjunction with capital pole line re-construction projects.

	2006 Actual	2006 EDR Approved	Var \$	Var %
5320-Collecting	426,995	341,055	85,940	25.2%

Variances in collecting are partially due to annual salary increases of 3% which accounts for approximately \$23,000 of the variance above (for 2005 and 2006). Additional costs incurred in 2006 actual include increases in the costs of delivering disconnect notifications and increased collection charges from WPI's third party collection agency.

	2006 Actual	2006 EDR Approved	Var \$	Var %
5335-Bad Debt Expense	6,101	175,000	(168,899)	(96.5%)

1
 2 The amount approved for bad debt for the 2006 EDR was based on historical data. 2006 is
 3 somewhat an outlier based on the fact that the Ontario Price Credit received in December 2005
 4 was applied to inactive accounts, therefore reducing the total amount of the write offs, and
 5 amounts were received from WPI's third party collection agency for accounts that had
 6 previously been written off.

	2006 Actual	2006 EDR Approved	Var \$	Var %
5610-Management Salaries and Expenses	425,925	682,350	(256,425)	(37.6%)
5615-General Administrative Salaries and Expenses	112,242	337,946	(225,704)	(66.8%)
5630-Outside Services Employed	240,708	368,602	(127,894)	(34.7%)
5665-Miscellaneous General Expenses	88,673	343,740	(255,067)	(74.2%)

8
 9 The above accounts have been grouped together as the reason for the variance year over the
 10 year provides the same response. In 2006 WPI had a Master Services agreement with its'
 11 affiliate Westario Power Services Inc. ('WPSI'). Under the MSA; WPSI provides certain
 12 operating, maintenance, administrative and capital construction services, including certain
 13 labour related expenses. In 2006, the expenses incurred by WPSI exceeded the amount
 14 allowed to be charged to WPI; therefore not all costs relating to the above expenses were
 15 charged in 2006. In the 2006 EDR year, the total costs incurred by WPSI did not exceed the
 16 amount as calculated by the MSA, therefore 100% of the costs were transferred.

17

	2006 Actual	2006 EDR Approved	Var \$	Var %
5670-Rent	50,983	122,873	(71,890)	(58.5%)

1
 2 In the 2006 EDR Approved year, WPSI leased four facilities; all of which were charged by WPSI
 3 to WPI under the MSA. In 2006 WPSI leased only two facilities. In addition, in 2006, the
 4 expenses incurred by WPSI exceeded the amount allowed to be charged to WPI; therefore not
 5 all costs relating to rent were charged to WPI by WPSI in 2006.

Shared Services

Westario Power Holdings Inc. ('WPHI') was a for-profit private business entity incorporated on November 1, 2000 pursuant to the Ontario Business Corporations Act.

The municipal shareholders of WPHI were Brockton, Hanover, Huron-Kinloss, Kincardine, Minto, Saugeen Shores, South Bruce, North Huron and its private equity owner, Fortis Ontario Inc. The subsidiaries of WPHI were:

Westario Power Inc. - Local Distribution Company

Westario Power Services Inc. - Services Company

WPHI's primary business was the oversight of its regulated affiliate – Westario Power Inc. Westario Power Inc. is a regulated Local Distribution Company (LDC) that owns and operates electricity distribution infrastructure. The company's service territory is an amalgamation of 15 communities distributed over four counties serving nearly 22,000 consumers.

Effective January 1, 2001, Westario Power Inc. entered in Master Services Agreements ('MSA') with Westario Power Holdings Inc. and Westario Power Services Inc. Copies of the MSA's can be found in Exhibit 4, Tab 2, Schedule 5.

On July 13, 2007 the Ontario Energy Board issued a decision and order (File #EB02007-0103) for Westario Power Inc. to amalgamate with Westario Power Holdings Inc. and Westario Power Services Inc. The amalgamation between Westario Power Inc., Westario Power Holdings Inc. and Westario Power Services Inc. became effective January 1, 2008. The shareholders of Westario Power Holdings Inc. remain the shareholders of the newly amalgamated company ('WPI').

The MSA's were effective from January 1, 2001 to December 31, 2007; therefore all costs submitted by WPI for previous rate applications were restricted by the parameters set within the

- 1 MSA's. As there is only one legal entity, Westario Power Inc. effective January 1, 2008; the
- 2 attached Master Service Agreements are no longer in effect.
- 3
- 4 Copies of the MSAs can be found as an attachment.
- 5

MASTER SERVICES AGREEMENT

THIS AGREEMENT made this 24th day of September, 2001

BETWEEN:

WESTARIO POWER SERVICES INC.

(hereinafter referred to as "Servco")

OF THE FIRST PART

- and -

WESTARIO POWER INC.

(hereinafter referred to as "Wiresco")

OF THE SECOND PART

WHEREAS each of Servco and Wiresco are duly incorporated pursuant to Section 142, Schedule A of the *Electricity Act, 1998*;

AND WHEREAS both Servco and Wiresco will operate as separate corporate entities, notwithstanding the provisions of this Agreement;

AND WHEREAS the Parties have agreed that Servco will maintain and repair Wiresco's electrical distribution system on a fee-for-service basis and Servco shall provide such and other products and services as may be agreed by the Parties from time to time;

AND WHEREAS the Parties acknowledge and agree that in providing goods and services Servco acts as an independent contractor and not as an agent, partner, or servant;

AND WHEREAS the Parties shall consult as frequently as may be desirable to ensure that Wiresco and its customers receive adequate, economical, safe and effective electrical distribution and ancillary services;

NOW THEREFORE IN CONSIDERATION of mutual covenants and agreements as set forth, and for other good and valuable considerations for the sum of two (\$2.00) dollars of lawful money of Canada now paid by each of the Parties to the other (the receipt and sufficiency of which is hereby expressly acknowledged), the Parties do hereby covenant and agree with each other, as follows:

1. Definitions

- 1.01 **"Capital Cost"** means the cost incurred for materials, equipment, overhead, and labour to provide capital works.
- 1.02 **"Capital Works"** has the meaning set out in Section 3.03.
- 1.03 **"Customer Service Costs"** means the cost incurred by a Party to bill and collect and to provide related customer services.
- 1.04 **"Customer Services"** means all services related to customer services, which without limiting the generality of the foregoing shall include customer billing collection of unpaid accounts, and customer relations, etc.
- 1.05 **"Direct Costs"** means the cost incurred directly by Wiresco for its own operations including but not limited to electrical power costs for Standard Supply Service, IMO costs, Transmission costs, Competition Transition Charge, Retail/Wholesale Settlement costs, Ministry of Finance OEB Regulatory costs, MEA dues, MEARIE insurance and other insurance premiums of Wiresco, and legal, accounting and audit fees of Wiresco.
- 1.06 **"Easements"** means any permissions, concessions, permits, licenses, interests, ways, privileges, easements and right-of-way to install, operate and maintain part or parts of the electrical distribution system over real property.
- 1.07 **"Effective Date"** means January 1, 2001.
- 1.08 **"Extraordinary Costs"** has the meaning set out in Section 4.05.
- 1.09 **"IMO"** means the Independent Electricity Market Operator for Ontario.
- 1.10 **"OM&A Costs"** means operations, maintenance, and administration costs incurred by Servco to distribute electric power within the areas serviced by Wiresco and include costs for the services described in Section 3.01.
- 1.11 **"Parties"** means Servco and Wiresco.

2. Term

- 2.01 Unless terminated in accordance with Article 9 of this Agreement, the term of this Agreement shall be from the Effective Date to and including December 31, 2003 and the term shall be extended automatically for further periods of two years each, unless either Party gives the other notice in writing not less than one hundred and eighty (180) days prior to the end of the term, or the end of renewal as the case may be that the Agreement is not to be extended.

3. Covenants of Servco

- 3.01 Servco agrees to maintain in a good and workmanlike manner Wiresco's electrical distribution system in all of the areas serviced by Wiresco from time to time.
- 3.02 In providing electrical distribution system maintenance services for Wiresco, Servco shall maintain at least the same performance standards as were delivered prior to the Effective Date in each of the municipalities within Wiresco's licensed service area and shall not discriminate in its performance between such municipalities nor any other parts of Wiresco's licensed service area. Servco shall render performance of the services to be provided hereunder in a competent and professional manner.
- 3.03 Servco shall expand or upgrade in a timely and in a good and workmanlike manner Wiresco's electrical distribution system at Wiresco's request, which shall hereinafter be referred to as "Capital Works", provided that such Capital Works have been designed in accordance with good engineering principles applicable in the Province of Ontario.
- 3.04 Servco shall assume Wiresco's responsibility for the installation and maintenance of municipal street lighting, which shall include park and walkway lighting as the case may be in the municipalities of Hanover, Saugeen Shores, Huron-Kinloss, Wingham, South Bruce, Kincardine, Minto and Brockton, and towards this end, shall make best efforts to execute an agreement with each Municipality for this service.
- 3.05 Subject to the obligations of Servco hereunder, Servco shall be free to offer services to any other person.
- 3.06 Servco shall be responsible for obtaining all necessary licences and permits and for complying with all applicable federal, provincial and municipal laws, codes and regulations in connection with the provision of the services hereunder and Servco shall when requested provide Wiresco with adequate evidence of its compliance with this Section 3.06.
- 3.07 Servco shall comply, while on the premises used by Wiresco, with all the rules and regulations of Wiresco from time to time in force, which are brought to its notice or of which it could reasonably be aware.

- 3.08 Servco shall pay for and maintain for the benefit of Servco appropriate insurance concerning the operations and liabilities of Servco 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 Servco to any employees of Servco and public liability and property damage insurance.
- 3.09 Servco shall indemnify and save Wiresco harmless from and against all claims, actions, losses, expenses, costs or damages of every nature and kind whatsoever which Wiresco or its officers, employees or agents may suffer as a result of the negligence of Servco in the performance or non-performance of this Agreement.
- 3.10 Servco 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 Wiresco or relating to any secrets of Wiresco to any person other than with the consent of Wiresco

4. Costs

- 4.01 Wiresco shall pay Servco the fees and charges more particularly outlined in Schedule "A" for OM&A Costs.
- 4.02 Wiresco shall assume and be directly responsible for its Direct Costs.
- 4.03 Wiresco shall reimburse Servco for its actual Capital Works costs, which without limiting the generality of the foregoing, shall include all Servco's direct labour and material costs, engineering design and review costs, plus overhead administration costs calculated at a percentage of the actual costs to be notified to Wiresco by Servco from time to time.
- 4.04 Wiresco agrees to reimburse Servco for any costs ("Extraordinary Costs") over and above OM&A and Capital Works costs, plus overhead administration costs calculated at a percentage of the actual costs to be notified to Wiresco from time to time, which Servco may incur resulting from extraordinary unanticipated events such as fires, major storms, tornadoes, equipment failures, acts of God and the like, provided such equipment failures are not caused by negligence on the part of Servco to provide routine service and maintenance of the electrical distribution system.
- 4.05 Upon renewal of the term of this Agreement and any subsequent renewals, Servco may adjust the OM&A, Capital Works Costs and Extraordinary Costs upon ninety (90) days prior notice in writing to Wiresco provided that, if Wiresco does not accept the adjusted costs and the Parties are unable to agree after negotiating in good faith, the adjusted costs may be submitted to arbitration pursuant to Article 9 of this Agreement.

5. Invoicing

- 5.01 Servco shall submit an invoice within 5 days from the end of each month to Wiresco for payment for all costs incurred by Servco in performing its services. All monthly invoices shall provide sufficient detail of the costs incurred and the description of the services undertaken by Servco. All invoices shall be paid by Wiresco within ten (10) days from the date of receipt.
- 5.02 Servco will submit details of any Extraordinary Costs to Wiresco for review before invoicing.

6. Easements

- 6.01 Wiresco represents that it has secured all requisite Easements necessary for the delivery of electrical services for the distribution of electric power throughout the Wiresco licensed service area as at the Effective Date.
- 6.02 Wiresco shall indemnify and save Servco harmless from any claims, demands, actions and applications brought against Servco arising from the failure of Wiresco to have secured the requisite Easements or from any defect or deficiency in the Easements secured by Wiresco prior to the Effective Date.
- 6.04 Servco shall act on behalf of Wiresco, and Wiresco appoints Servco its agent for the purposes of this Section 6.04, to secure all Easements required for the performance of the expansion or upgrade of electrical distribution services pursuant to this Agreement. Any costs related to the acquisition of Easements, including appraisal and legal costs, shall be paid by Wiresco

7. Customer Billing

- 7.01 Servco shall provide billing services to Wiresco as requested from time to time but all bills shall be issued in Wiresco's name.
- 7.02 Wiresco shall be responsible for all costs related to any billing errors and uncollectible bills incurred on or before the commencement of this Agreement and shall indemnify and save Servco harmless in respect thereof.
- 7.03 Servco shall assume responsibility for any billing errors arising after the commencement of this Agreement only to the extent that the costs arising from the billing errors are unrecoverable from Wiresco's customer and only if the billing error is attributable to Servco's negligence or the negligence of its servants, agents or representatives.

8. Arbitration

- 8.01 The Parties agree to consult with each other and to negotiate in good faith to resolve any differences or disputes which either Party may have relating to the interpretation, application or implementation of this Agreement, or any dispute

which may arise over any costs, fees or other costs incurred and failing agreement the Parties agree to resolve their disputes by arbitration as provided in this Article 8.

- 8.02 Arbitration of a dispute shall be commenced by written notice by a Party requesting arbitration to the other, which notice shall identify the issue or issues it wishes to submit to arbitration. Within thirty (30) days of the date of the notice, the Parties shall agree upon a single arbitrator and failing agreement then each Party shall appoint an arbitrator and the two appointees shall within 45 days of the date of the notice of arbitration appoint a third person who shall act as Chair of the arbitration panel, and failing agreement the Chair shall be appointed by a judge of the Superior Court of Ontario pursuant to the provisions of the *Arbitration Act*, R.S.O. 1991, c. A.17.
- 8.03 The commencement of the arbitration and all rules of procedure for the arbitration shall be by agreement of the Parties, or failing agreement, as determined by the arbitrator or Chair of the arbitration panel. The provisions of the *Arbitration's Act*, R.S.O. 1991, c. A.17, as amended or any successor legislation shall apply to the arbitration.
- 8.04 All decisions of the arbitrator or arbitrators, as the case may be, shall be made in writing and shall be delivered to all Parties within ten (10) days from the conclusion of the arbitration. All decisions shall be final and binding upon the Parties, their respective successors and assigns, and shall not be subject to appeal.
- 8.05 Each Party shall pay its own costs incurred in respect of the arbitration including the payment of its appointee to the arbitration panel, and in the case of a three person panel the Parties agree to share the fees of the Chair and other related costs equally.

9. Termination

- 9.01 In the event of non-performance by either Party of its obligations under this Agreement, the other Party may at its sole option elect to terminate this Agreement provided that the defaulting Party shall be given written notice of the default and shall be given sixty (60) days to cure the default, and then only upon failure to cure the default the Agreement may be terminated.
- 9.02 Notwithstanding any termination of this Agreement for any reason whatsoever and with or without cause, the provisions of Sections 3.09 and 3.10 and any other provisions of this Agreement necessary to give efficacy thereto shall continue in full force and effect following any such termination.

10. Warranty

- 10.01 Servco provides no warranty or guarantee for any defective or deficient equipment or materials supplied except for the manufacturer's or supplier's

warranties or guarantees applicable to the defective or deficient equipment or materials.

11. New Business Opportunities

- 11.01 Servco intends to explore and develop new business opportunities for the retail sale of products and services to its customers and those customers in areas serviced by Wiresco.
- 11.02 Servco agrees to disclose to Wiresco its new business and marketing plans, including projected revenues and expenses as they pertain to Wiresco, for new business opportunities as they arise from time to time provided that such plans are treated as confidential as between the Parties unless otherwise agreed in writing by Servco.
- 11.03 Servco agrees to extend to Wiresco the opportunity to participate in its new business opportunities and agrees to negotiate in good faith the terms upon which Wiresco may participate in such opportunities, provided that if the Parties fail to agree to terms upon which Wiresco is to participate in such new business opportunities, the disagreement shall not be submitted to an arbitrator under Article 8 unless the Parties otherwise agree, and provided further that failing agreement Servco will not be precluded from pursuing the new business opportunity or opportunities unilaterally without participation of Wiresco in areas now serviced by Wiresco.

12. Notices

- 12.01 All notices required to be given to either of the Parties under this Agreement shall be in writing and shall be delivered by prepaid unregistered post or hand delivery to the following:

a) in the case of Servco, to:

Westario Power Services Inc.
385 Queen Street,
Kincardine, Ontario N2Z 2R4

Attention: President

Telephone: (519) 396-3471
Fax: (519) 396-7605

b) in the case of Wiresco, to:

Westario Power Inc.
385 Queen Street,
Kincardine, Ontario N2Z 2R4

Attention: President

Telephone: (519) 396-3471
Fax: (519) 396-7605

or to such other address or individual as may be designated by written notice to the other Party. Any notice given by personal delivery shall be deemed to have been given on the day of actual delivery hereof and it sent by prepaid post, on the third day after mailing.

13. Regulatory Changes

13.01 The Parties acknowledge that substantial changes to legislation and regulations and government policies are likely to occur during the term of this Agreement which are likely to affect the nature of the relationship between them, and as consequence the Parties hereby agree to consult and negotiate in good faith any amendments to this Agreement which may be necessitated by changes in the regulatory environment, and failing agreement to submit their differences to arbitration as provided in Article 8.

14. Relationship and Agency

14.01 Servco's obligations in connection with this Agreement are contractual in nature only. The legal relationship between the Parties established by this Agreement is that of Servco serving solely as an independent contractor providing specified services to Wiresco on an arm's length basis and, without limitation, the relationship is not intended to be, and shall not, unless specifically provided herein, be deemed or considered to be, one of, joint venture, co-venture or trustee-beneficiary and therefore neither Party will owe any fiduciary or similar duty, other than pursuant to Section 14.02, to the other Party under this Agreement, all of which are expressly disclaimed.

14.02 Wiresco appoints Servco as its agent for the following purposes:

- (a) the purposes set out in Section 6.03;
- (b) purchasing and procurement, in accordance with the guidelines and policies of Wiresco in effect from time to time as notified to Servco;

- (c) entering into agreements or other arrangements with builders, developers and similar parties with respect to the provision of electricity distribution and ancillary services, including without limitation agreements or other arrangements in respect of capital contribution;
- (d) any other commercial arrangements as may be agreed to by the Parties from time to time for the purposes of carrying out this Agreement

15. General Provision

- 15.01 This Agreement shall ensure to the benefit of and be binding upon the Parties and their successors and assigns, respectively.
- 15.02 For the purposes of this Agreement, whenever the term Servco or Wiresco is used, the term shall be deemed to include all successor business corporations incorporated to whom assets and liabilities are transferred for the purpose of the installation, operation and maintenance of the Parties' electrical distribution systems.
- 15.03 The division 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 "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.
- 15.04 In this Agreement words importing the singular number only include the plural and plus overhead administration costs calculated at a percentage of the actual costs to be notified to Wiresco from time to time 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.
- 15.05 This Agreement constitutes the entire agreement between the Parties with respect to the subject matter hereof and cancels and supersedes any prior understanding 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.
- 15.06 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.

- 15.07 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.
- 15.08 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 such provision and all other provisions hereof shall continue in full force and effect.
- 15.09 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
- 15.10 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.

IN WITNESS WHEREOF the Parties have duly executed this Agreement on the date first above written.

WESTARIO POWER SERVICES INC.

Per:



Title:

PRESIDENT / CEO

Title:

WESTARIO POWER INC.

Per:



Title:

PRESIDENT / CEO

Title:

SCHEDULE A

OM&A Costs shall be paid monthly in an amount calculated as follows:

$$\frac{x + y}{12} = z$$

Where:

- $x =$ the aggregate of all of the operations, management and administration costs set out in the 1999 rate applications of the predecessor municipal electric utilities of Wiresco
- $y =$ the depreciation amount in the budget of Servco for the applicable fiscal year
- $z =$ the monthly payment by Wiresco to Servco in respect of OM&A Costs

PROVIDED THAT at the end of the applicable fiscal year an adjustment shall be made to reflect actual (as opposed to budgeted) depreciation applicable to Servco.

Capitalized terms used in this Schedule A shall have those meanings ascribed to them in Article 1 – Definitions.

MASTER SERVICES AGREEMENT

THIS AGREEMENT made this 24th. day of September, 2001

BETWEEN:

WESTARIO POWER HOLDINGS INC.

(hereinafter referred to as "Holdco")

OF THE FIRST PART

- and -

WESTARIO POWER INC.

(hereinafter referred to as "Wiresco")

OF THE SECOND PART

WHEREAS each of Holdco and Wiresco are duly incorporated pursuant to Section 142 of the *Electricity Act, 1998*;

AND WHEREAS the Parties have agreed that Holdco shall provide such services as may be agreed by the Parties from time to time;

AND WHEREAS the Parties acknowledge and agree that in providing services Holdco acts as an independent contractor and not as an agent, partner, or servant;

NOW THEREFORE IN CONSIDERATION of mutual covenants and agreements as set forth, and for other good and valuable considerations for the sum of two (\$2.00) dollars of lawful money of Canada now paid by each of the Parties to the other (the receipt and sufficiency of which is hereby expressly acknowledged), the Parties do hereby covenant and agree with each other, as follows:

1. **Definitions**

1.01 **"Effective Date"** means January 1, 2001.

1.02 **"Parties"** means Holdco and Wiresco.

1.03 **"Services"** means the administrative and corporate services that Holdco shall agree to provide and Wiresco shall agree to purchase from time to time.

2. **Term**

2.01 Unless terminated in accordance with Article 6 of this Agreement, the term of this Agreement shall be from the Effective Date to and including the earlier of:

(i) December 31, 2003, and

(ii) the coming into force of substantial revisions to the Electricity Distribution Rate Handbook (as of October 1, 2001) (the "Handbook") of the Ontario Energy Board to reflect changes to the performance based regulation ("PBR") framework contained in the Handbook where such substantial revisions have been made for the purpose of implementing "2nd generation PBR" (as that term is used in section 1.2 of Chapter 1 of the Handbook issued on November 3, 2000);

and the term shall be extended automatically for further periods of one year each, unless either Party gives the other notice in writing not less than one hundred and eighty (180) days prior to the end of the term, or the end of renewal as the case may be that the Agreement is not to be extended.

3. **Covenants**

3.01 Holdco agrees to provide and Wiresco agrees to purchase the Services.

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

3.03 Holdco 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 Wiresco or relating to any secrets of Wiresco to any person other than with the consent of Wiresco.

4. **Fees**

- 4.01 Wiresco shall pay to Holdco fees equal to the cost to Holdco of providing the Services.

5. **Invoicing**

- 5.01 Holdco shall submit an invoice within five (5) days from the end of each month to Wiresco for payment for all estimated costs incurred by Holdco in providing the Services for such month. All monthly invoices shall provide sufficient detail of the estimated costs incurred and the description of the Services undertaken by Holdco. All invoices shall be paid by Wiresco within ten (10) days from the date of receipt.
- 5.02 At the end of each fiscal year, Holdco shall calculate its actual costs incurred in providing the Services for such fiscal year and shall invoice or credit Wiresco an appropriate amount such that the aggregate fees paid by Wiresco in respect of the Services for such fiscal year are in accordance with Section 4.01.

6. **Termination**

- 6.01 In the event of non-performance by either Party of its obligations under this Agreement, the other Party may at its sole option elect to terminate this Agreement provided that the defaulting Party shall be given written notice of the default and shall be given sixty (60) days to cure the default, and then only upon failure to cure the default the Agreement may be terminated.
- 6.02 Notwithstanding any termination of this Agreement for any reason whatsoever and with or without cause, Section 3.02 and 3.03 and any other provisions of this Agreement necessary to give efficacy thereto shall continue in full force and effect following any such termination.

7. **Notices**

- 7.01 All notices required to be given to either of the Parties under this Agreement shall be in writing and shall be delivered by prepaid unregistered post or hand delivery to the following:

- (a) in the case of Holdco, to:

Westario Power Holdings Inc.
385 Queen Street,
Kincardine, Ontario N2Z 2R4

Attention: President

Telephone: (519) 396-3471
Fax: (519) 396-7605

- (b) in the case of Wiresco, to:

Westario Power Inc.
385 Queen Street,
Kincardine, Ontario N2Z 2R4

Attention: President

Telephone: (519) 396-3471
Fax: (519) 396-7605

or to such other address or individual as may be designated by written notice to the other Party. Any notice given by personal delivery shall be deemed to have been given on the day of actual delivery hereof and it sent by prepaid post, on the third day after mailing.

8. **Regulatory Changes**

- 8.01 The Parties acknowledge that substantial changes to legislation and regulations and government policies may occur during the term of this Agreement which may affect the nature of the relationship between them, and as consequence the Parties hereby agree to consult and negotiate in good faith any amendments to this Agreement which may be necessitated by changes in the regulatory environment.

9. **Relationship**

- 9.01 Holdco's obligations in connection with this Agreement are contractual in nature only. The legal relationship between the Parties established by this Agreement is that of Holdco serving solely as an independent contractor providing specified services to Wiresco on an arm's length basis and, without limitation, the relationship is not intended to be, and shall not be deemed or considered to be, one of, joint venture, co-venture, agency or trustee-beneficiary and therefore neither Party will owe any fiduciary or similar duty to the other Party under this Agreement, all of which are expressly disclaimed.

10. **General Provisions**

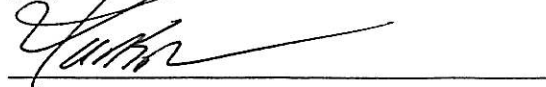
- 10.01 This Agreement shall ensure to the benefit of and be binding upon the Parties and their successors and assigns, respectively.
- 10.02 The division of this Agreement into Articles and Sections and the insertion of headings are for the convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms "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.

- 10.03 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.
- 10.04 This Agreement constitutes the entire agreement between the Parties with respect to the subject matter hereof and cancels and supersedes any prior understanding 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.
- 10.05 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.
- 10.06 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.
- 10.07 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 such provision and all other provisions hereof shall continue in full force and effect.
- 10.08 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
- 10.09 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.

IN WITNESS WHEREOF the Parties have duly executed this Agreement on the date first above written.

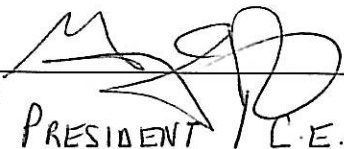
WESTARIO POWER HOLDINGS INC.

Per:



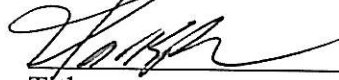
Title: CHAIRMAN - BOARD OF DIRECTORS

Per:


Title: _____
PRESIDENT / C.E.O.

WESTARIO POWER INC.

Per:

A handwritten signature in black ink, appearing to be 'J. Smith', written over a horizontal line.

Title:

Per:

A handwritten signature in black ink, appearing to be 'M. Smith', written over a horizontal line.

Title:

Corporate Cost Allocation

The applicant entered into a Master Services Agreement with Westario Power Services Inc. ("WPSI") for the period of January 1, 2001 to December 31, 2007 for the purposes of maintaining and repairing WPI's electrical distribution system on a fee-for-service basis, and other products and services as may be agreed upon from time to time by both WPI and WPSI. A copy of the Master Service Agreement, including the cost allocation can be found in Exhibit 4, Tab 2, Schedule 4.

The applicant entered into a Master Services Agreement with Westario Power Holdings Inc. ("WPHI") for the period of January 1, 2001 to December 31, 2007 for the purposes of administrative and corporate services as may be agreed upon from time to time by both WPI and WPHI. A copy of the Master Service Agreement, including the cost allocation can be found in Exhibit 4, Tab 2, Schedule 4.

1 **Purchase of Services**

2

3 All service providers in excess of a materiality threshold of \$50,000 are listed below:

1

Vendor and Related Service Acquired	2006	2006	2007	2008	2009
	EDR Actual	Actual	Actual	Bridge Year	Test Year
Accurate Meter Reading	Expense of affiliate company	Expense of affiliate company	Expense of affiliate company	\$ 327,000	\$ 331,775
Contracted to read meters, complete final meter reads, deliver disconnect notices, perform disconnects and reconnects and provide Itron-related equipment.					
We had previously utilized the services of Olameter-URB until mid-2004.					
The selection of the current service provider was via an RFP for a 3 year contract. A selection criteria process identified cost, prior experience, convenience of local presence and ability to attend offices to upload data, and ability to adhere to WPI's safe work practices as factors to be considered.					
The current contract expires June 30, 2009. Costs are expected to be significantly different once smart meters are deployed.					
It is cost prohibitive to do these processes internally.					

2

Vendor and Related Service Acquired	2006	2006	2007	2008	2009
	EDR Actual	Actual	Actual	Bridge Year	Test Year
Automated Solutions Inc.	Expense of affiliate company	Expense of affiliate company	Expense of affiliate company	\$ 16,000	\$ 0
Provide map maintenance and assistance with special projects such as GIS conversion.					
Westario Power Inc. has been dealing with this service provider since inception in 2000, as did the predecessor utilities.					
Westario Power Inc. has hired an in-house staff member to provide GIS mapping services, therefore the services provided by this vendor will decrease in the bridge year and will no longer be incurred in the test year.					

3

4

1

Vendor and Related Service Acquired	2006	2006	2007	2008	2009
	EDR Actual	Actual	Actual	Bridge Year	Test Year
Canadian Niagara Power Inc. (CNPI)	\$ 61,889	\$ 99,538	\$ 85,993	\$ 94,960	\$ 142,861
This company provides basis, non-basis and IT support services to Westario Power Inc.					
Basis services relate to SAP design and maintenance of base hardware and software systems, installing upgrades as needed, and backing up and storing data.					
Non-basis services are for EBT retailer-related transactions, including invoicing and transferring data in and out of the hub.					
IT support services refer to assistance with non-routine issues, software and network support.					
In 2009, network issues and support services are expected to be provided by CNPI as the current in-house IT individual is retiring in the fall of 2008 and no replacement is anticipated.					
CNPI provides support and backup for WPI's CIS system. It is cost prohibitive for WPI to complete this function in house. No other service providers are available to WPI.					
The current annual agreement for basis and non-basis services expires April 30, 2009.					

2

Vendor and Related Service Acquired	2006	2006	2007	2008	2009
	EDR Actual	Actual	Actual	Bridge Year	Test Year
Utilismart Corporation	\$ 77,121	\$ 81,199	\$ 82,089	\$ 84,468	\$ 85,000
Contracted to provide data collection and monitoring of daily wholesale and retail interval meters.					
When the market opened, there were very few companies that provided this service. This LDC utilized the services of Bluewater Power initially and later began using Utilismart March 1, 2003.					
The current contract expires Feb 28, 2009.					

3

1

Vendor and Related Service Acquired	2006	2006	2007	2008	2009
	EDR Actual	Actual	Actual	Bridge Year	Test Year
Westario Power Holdings Inc.	\$ 516,767	\$ 451,857	\$ 462,463	Nil	Nil
Management and administrative services under the terms of a master services agreement, including certain operating, and administrative services (including certain labour-related expenses).					

2

Vendor and Related Service Acquired	2006	2006	2007	2008	2009
	EDR Actual	Actual	Actual	Bridge Year	Test Year
Westario Power Services Inc.	\$ 3,499,816	\$ 3,859,216	\$ 3,277,651	Nil	Nil
Management and administrative services under the terms of a master services agreement, including certain operating, maintenance, administrative and capital construction services (including certain labour-related expenses).					

3

Vendor and Related Service Acquired	2006	2006	2007	2008	2009
	EDR Actual	Actual	Actual	Bridge Year	Test Year
Credit Bureau of Owen Sound	Expense of affiliate company	Expense of affiliate company	Expense of affiliate company	\$ 38,000	\$ 55,000
Contracted to follow up on collections, issue preparation fees (legal paperwork for small claims court), perform asset investigations, perform examinations at small claims court, entertain motions, attend settlement conferences and trials, and disbursement fees of personal services by a process server.					
The selection of the current service provider was via an RFP. A selection criteria process identified cost, prior experience and convenience of local presence as factors to be considered. The contract was entered into in July 2004.					
The current contract is open-ended.					
It is cost prohibitive to do these processes internally.					

4

5

1

Vendor and Related Service Acquired	2006	2006	2007	2008	2009
	EDR Actual	Actual	Actual	Bridge Year	Test Year
Rodan Energy Inc.	\$ 30,458	\$ 61,699	\$ 45,378	\$ 52,000	\$ 54,000
Rodan has been providing MSP services to Westario Power Inc. since 2002.					
Rodan is competitively priced with alternative organizations.					

2

Vendor and Related Service Acquired	2006	2006	2007	2008	2009
	EDR Actual	Actual	Actual	Bridge Year	Test Year
Fortis Ontario	Nil	Expense of affiliate company	Expense of affiliate company	\$ 2,400	0
Contracted to assist with Finance services during period of being without a Finance Manager (began spring 2006).					
Able to leverage off the knowledge of a company in the industry and therefore no outside bid obtained.					
Service contract expired Dec 31 2007 and was not renewed due to the hiring of an additional management resource in December 2007.					

3

Vendor and Related Service Acquired	2006	2006	2007	2008	2009
	EDR Actual	Actual	Actual	Bridge Year	Test Year
SAP	\$ 45,517	\$ 67,439	\$ 75,106	\$ 70,500	\$ 83,334
Westario Power utilizes SAP software for the electronic operations of the business. It has proven to be very powerful for managing the customer service side of our business.					
The annual costs include the annual licensing fee charged by SAP as well as a small annual fee for remote access to the system.					

4

5

Employee Description

Prior to January 1, 2008; the Applicant had no employees. Prior to January 1, 2008, certain operating, maintenance, administrative and capital construction services, including certain labour-related expenses, were provided by the applicant's affiliates Westario Power Services Inc. and Westario Power Holdings Inc. The historical data presented is based on the compensation paid to the employees of the affiliate. This methodology is consistent with the Applicant's 2006 EDR Application (EB-2005-0020). Where appropriate, the numbers below have been normalized to take into account the fact that there are times during a fiscal year that there will be gaps between vacant positions being filled.

Number of Employees (Full-time equivalents (FTEs))

Group	2006 EDR	2006	2007	2008	2009
Executive	10	10	10	10	10
Management	7	7	8	8	8
Unionized	27	29	29	30	30

Compensation - Average Yearly Base Wage (\$)

Group	2006 EDR	2006	2007	2008	2009
Executive	\$23,714	\$24,560	\$24,989	\$25,482	\$26,246
Management	\$79,161	\$72,600	\$75,800	\$80,377	\$82,788
Unionized	\$40,608	\$47,105	\$51,470	\$51,768	\$53,321

Compensation - Average Yearly Overtime (\$)

Group	2006 EDR	2006	2007	2008	2009
Executive					
Management	\$10,426	\$22,415	\$6,206	\$5,315	\$5,474
Unionized	\$6,349	\$11,178	\$5,108	\$8,000	\$8,240

Compensation-Average Yearly Incentive (\$)

Group	2006 EDR	2006	2007	2008	2009
Executive	\$2,010	\$3,600	\$4,370	\$4,370	\$4,501
Management	\$3,663	\$3,202	\$3,069	\$4,782	\$4,925
Unionized					

1

Compensation-Average Yearly Benefits (\$)

8	2006 EDR	2006	2007	2008	2009
Executive	\$3,039	\$2,559	\$2,384	\$2,384	\$2,503
Management	\$13,749	\$11,651	\$10,495	\$11,364	\$12,903
Unionized	\$14,071	\$8,180	\$8,514	\$8,419	\$9,015

2

3

Loss Adjustment Factor Calculation

		2004	2005	2006	2007
(A)	"Wholesale" kWh (IESO)	451,255,185	456,178,576	446,710,143	459,504,026
(B)	Wholesale kWh for Large Use customer(s) (IESO)	17,833,293	19,984,727	18,972,099	20,223,835
C	Net "Wholesale" kWh (A)-(B)	433,421,892	436,193,849	427,738,044	439,280,191
(D)	Retail kWh (Distributor)	427,467,654	426,510,177	430,593,345	438,283,096
(E)	Retail kWh for Large Use Customer(s) (1% loss)	17,220,268	19,331,718	18,308,889	19,486,141
(F)	Net "Retail" kWh (D)-(E)	410,247,386	407,178,459	412,284,456	418,796,955
	Loss Factor [(C)/(F)]	1.0565	1.0713	1.0375	1.0489
	Distribution Loss Adjustment Factor (4 year average)				1.0535

Total Utility Loss Adjustment Factor

Supply Facility Loss Factor	1.024
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW	1.0535
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0430
TOTAL LOSS FACTOR	
Total Loss Factor - Secondary Metered Customer < 5,000kW	1.0788
Total Loss Factor - Primary Metered Customer < 5,000kW	1.0680

Details of Retail kWh (Distributor) and Supply Loss Factor are provided in attachment 1 and 2, respectively.

Details of Total Losses

Westario Power Supply Overview

Westario Power is a wholly embedded LDC, surrounded by Hydro One franchise territory. Westario Power does not own any Transformer Stations (TS) and as such receives power from the Hydro One distribution network or sub-transmission system.

At its boundaries with Hydro One, Westario Power has IESO compliant wholesale meter equipment. Because Westario Power is comprised of 15 municipalities, it owns and maintains 20 wholesale metering sites; served from 4 Hydro One Transformer Stations. Many of the wholesale metering points for Westario Power municipalities are at the end of feeders - a considerable distance from the Transformer Station(s) supplying the community.

It would appear that Total Uplift Factor established in the 2006 EDR of 1.0637 is lower than the actual factor as evidenced by the continued growth in the RSVA Power Variance Account.

In June 2008, the OEB Regulatory Audit Office released a report entitled *Ontario Electricity Distributor Practices Relating to Management of System Losses (The Report)*. This report, which is presented as an attachment in this section, provides an extensive review of electricity distributor practices relating to the management of system losses.

Total Uplift Factor

The Total Uplift Factor (TUF) is calculated as the product of the Supply Loss Uplift Factor (SLUF) and the Distribution System Loss Uplift Factor (DSLUF).

Supply Loss Uplift Factor (SLUF)

Supply Loss Factor is the energy loss between the point of delivery and primary metering equipment at the boundary. In the 2006 EDR, Westario Power applied to utilize the default SLUF of 1.0045. The actual uplift factor is 1.024 and has been applied for in this application.

Distribution System Loss Uplift Factor (DSLUF)

Line loss is the energy loss when comparing the energy delivered through the boundary Wholesale Metering Points and the downstream meters. In 2006 EDR Westario Power applied for, and received approval for, DSLUF of 1.0589.

The term *distribution system loss* is typically used to describe two types of losses, technical and non-technical:

- Technical losses on distribution systems are primarily due to heat dissipation resulting from (a) current passing through resistance in conductors and (b) from magnetic losses in transformers, which include a conductor loss and a core loss. The core loss does not vary with loading. Technical losses can be estimated analytically.
- Non-technical losses occur as a result of theft, billing errors, metering inaccuracies and unmetered energy. Such losses cannot be quantified analytically other than by subtracting technical losses from total losses.

Westario Power Loss Calculations

The following table provides the actual DSLUF calculations for 2004 to 2007.

	2004	2005	2006	2007
"Wholesale" kWh (IESO)	451,255,185	456,178,576	446,710,143	459,504,026
Wholesale kWh for Large Use customer(s) (IESO)	17,833,293	19,984,727	18,972,099	20,223,835
Net "Wholesale" kWh (A)-(B)	433,421,892	436,193,849	427,738,044	439,280,191
Retail kWh (Distributor)	427,467,654	426,510,177	430,593,345	438,283,096
Retail kWh for Large Use Customer(s) (1% loss)	17,220,268	19,331,718	18,308,889	19,486,141
Net "Retail" kWh (D)-(E)	410,247,386	407,178,459	412,284,456	418,796,955
Loss Factor [(C)/(F)]	1.0565	1.0713	1.0375	1.0489
Distribution Loss Adjustment Factor (4 year average)				1.0535

The difference in the Total Uplift Factor using the actual versus 2006 EDR default SLUF is shown in the following table:

	Current Uplift	Proposed Uplift
Supply Facility Loss Factor	1.0045	1.0240
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW	1.0589	1.0535
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0480	1.0430
TOTAL LOSS FACTOR		
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0637	1.0788
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0530	1.0680
Difference to Current Factor		0.0151

Westario Power Mitigation Efforts

The communities that Westario serves are small towns and villages. This leaves little opportunity to reduce losses by changing the circuit routing supplying loads.

For the most part, these communities are fully developed to the boundaries of Westario's licensed distribution territories. While development is still occurring in some municipalities, it is doing so outside of Westario's service territories. This hampers the opportunity to reduce losses as a consideration in the design of new distribution system expansions.

The Company has identified a substantial amount of #6 copper conductor in many of the communities, as evidenced in Exhibit 2, Tab 3, Schedule 1. Replacing this conductor has been established as a high priority for a number of reasons including;

- Age
 - 30 years or more.
- Deteriorated Condition
 - With age this conductor becomes very brittle thereby affecting reliability and public/worker safety.
- Line Losses
 - By today's standards, this size of conductor is very small. With its small diameter comes increased line losses.

Continuing and expanding on the capital projects carried out over recent years, the 2009 Capital Works identified in this application proposes a more aggressive plan to replace #6 copper.

Additionally, other past and proposed capital projects address line losses by removing undersized and over utilized assets from service and replacing them with larger capacity and more robust plant. Examples of these projects are as follows:

- Pole line rebuild projects seeks to replace undersized main feeders with new larger capacity feeders, thus reducing loss.
- The 5 kV cable replacement program is a similar issue to that the No. 6 copper issue except that the work is replacement of underground cables and transformers. The old style of inefficient and overloaded transformers are displaced and replaced with new, more efficient transformers.
- A project to replace old thermal demand poly-phase meters with new electronic demand meters. Meter error accuracy in old mechanical meters will be reduced. Mechanical meters tend to register lower readings as they fail, unlike electronic meters which cease to display upon failure.

These initiatives will retire undersized feeder and conductors and deploy more accurate meters into the distribution system. With the impending deployment of smart meters, more accurate information will become available to compare deliver electricity to actual consumption.

Under this application, Westario Power is applying for a Total Uplift Factor of 1.0788.

Retail kWh

	January to December 2004				January to December 2005			
	Metered kWh	Add unbilled (billed in 2005)	Less 2003 Unbilled	Total	Metered kWh	Add unbilled (billed in 2006)	Less 2004 Unbilled	Total
Residential	197,561,106	25,543,930	-26,140,242	196,964,793	195,802,935	24,039,655	-25,543,930	194,298,660
< 50	71,134,186	8,785,867	-9,428,035	70,492,018	69,391,252	8,547,127	-8,785,867	69,152,511
Unmetered	<u>532,835</u>	<u>81,455</u>	<u>-61,188</u>	<u>553,102</u>	<u>549,568</u>	<u>70,613</u>	<u>-81,455</u>	<u>538,726</u>
	71,667,021	8,867,322	-9,489,223	71,045,120	69,940,820	8,617,739	-8,867,322	69,691,237
> 50	162,629,079	23,226,393	-31,003,638	154,851,835	158,289,111	21,881,642	-23,226,393	156,944,360
Street lighting	3,898,568	1,160,484	-462,602	4,596,450	6,204,392	525,310	-1,160,484	5,569,218
Sentinel lighting	<u>10,741</u>	<u>3,171</u>	<u>-3,709</u>	<u>10,203</u>	<u>7,150</u>	<u>2,731</u>	<u>-3,171</u>	<u>6,710</u>
	435,766,515	58,801,301	-67,099,415	427,468,400	430,244,408	55,067,077	-58,801,301	426,510,185

Retail kWh

	January to December 2006				January to December 2007			
	Metered kWh	Add unbilled (billed in 2007)	Less 2005 Unbilled	Total	Metered kWh	Add unbilled (billed in 2008)	Less 2006 Unbilled	Total
Residential	196,772,341	24,637,414	-24,039,655	197,370,101	200,397,263	23,432,876	-24,637,414	199,192,725
< 50	69,186,553	8,148,044	-8,547,127	68,787,471	71,456,354	8,109,192	-8,148,044	71,417,502
Unmetered	<u>528,721</u>	<u>57,061</u>	<u>-70,613</u>	<u>515,168</u>	<u>501,647</u>	<u>51,297</u>	<u>-57,061</u>	<u>495,884</u>
	69,715,274	8,205,105	-8,617,739	69,302,640	71,958,001	8,160,489	-8,205,105	71,913,385
> 50	162,035,803	19,146,917	-21,881,642	159,301,078	163,433,488	18,747,516	-19,146,917	163,034,087
Street lighting	4,644,948	488,863	-525,310	4,608,500	4,119,804	496,682	-488,863	4,127,624
Sentinel lighting	<u>14,130</u>	<u>2,483</u>	<u>-2,731</u>	<u>13,882</u>	<u>16,635</u>	<u>2,581</u>	<u>-2,483</u>	<u>16,733</u>
	433,182,496	52,480,783	-55,067,077	430,596,202	439,925,192	50,840,144	-52,480,783	438,284,554

Supply Loss Factor

2007				2006			
	Measured Qty	Billed Qty	difference	Measured Qty	Billed Qty	difference	
Jan	47,095,766.14	48,286,431.24	1.0253	44,937,034.51	46,064,475.16	1.0251	
Feb	46,263,513.59	47,448,566.99	1.0256	42,691,243.57	43,769,173.44	1.0252	
Mar	42,930,126.35	43,997,375.97	1.0249	43,508,741.54	44,589,097.48	1.0248	
Apr	36,963,796.33	37,879,233.75	1.0248	33,743,145.57	34,561,438.67	1.0243	
May	32,508,070.44	33,277,384.93	1.0237	32,729,519.88	33,500,100	1.0235	
Jun	32,770,636.66	33,526,730.41	1.0231	31,566,329.91	32,292,809.30	1.0230	
Jul	32,951,891.30	33,718,867.58	1.0233	34,917,039.22	35,725,512.81	1.0232	
Aug	34,566,787.91	35,375,178	1.0234	33,277,985.04	34,058,254.86	1.0234	
Sept	31,514,547.14	32,250,436.34	1.0234	30,847,691.66	31,567,429.65	1.0233	
Oct	33,950,544.21	34,752,604.92	1.0236	36,246,656.90	37,120,106.86	1.0241	
Nov	40,357,584.85	41,468,655.28	1.0275	38,532,455.91	39,472,092.50	1.0244	
Dec	47,630,762.03	49,005,909.47	1.0289	43,712,299.11	44,806,003.72	1.0250	
Average			1.0248			1.0241	

2005				2004			
	Measured Qty	Billed Qty	difference	Measured Qty	Billed Qty	difference	
Jan	49,997,724.90	51,275,342.40	1.0256	50,305,894.44	51,459,673.31	1.0229	
Feb	40,417,873.70	41,425,123.49	1.0249	43,870,842.59	44,866,583.26	1.0227	
Mar	44,241,745.85	45,356,899.03	1.0252	42,606,311.40	43,549,314.65	1.0221	
Apr	34,643,522.27	35,500,263.33	1.0247	36,626,321.71	37,418,898.12	1.0216	
May	32,269,593.48	33,044,468.96	1.0240	32,216,445.21	32,898,748.46	1.0212	
Jun	34,391,246.60	35,170,230.55	1.0227	30,459,512.23	31,090,709.27	1.0207	
Jul	34,544,463.23	35,348,112.30	1.0233	31,672,397.57	32,346,651.07	1.0213	
Aug	34,610,070.03	35,411,833.30	1.0232	32,146,210.50	32,824,923.92	1.0211	
Sept	31,186,828.44	31,906,471.10	1.0231	31,723,221.63	32,384,284.22	1.0208	
Oct	33,922,766.76	34,729,942.23	1.0238	33,792,681.41	34,587,750.20	1.0235	
Nov	38,602,482.99	39,543,214.88	1.0244	38,371,359.07	39,308,754.04	1.0244	
Dec	47,350,257.73	48,544,678.62	1.0252	47,463,986.91	48,656,671.99	1.0251	
Average			1.0242			1.0223	

Supply Loss Factor (4 years average)

1.024

LOSS ADJUSTMENT FACTOR CALCULATION

	2004	2005	2006	2007
(A) "Wholesale" kWh (IESO)	451,255,185	456,178,576	446,710,143	459,504,026
(B) Wholesale kWh for Large Use customer(s) (IESO)	17,833,293	19,984,727	18,972,099	20,223,835
C Net "Wholesale" kWh (A)-(B)	433,421,892	436,193,849	427,738,044	439,280,191
(D) Retail kWh (Distributor)	427,467,654	426,510,177	430,593,345	438,283,096
(E) Retail kWh for Large Use Customer(s) (1% loss)	17,220,268	19,331,718	18,308,889	19,486,141
(F) Net "Retail" kWh (D)-(E)	410,247,386	407,178,459	412,284,456	418,796,955
Loss Factor [(C)/(F)]	1.0565	1.0713	1.0375	1.0489
Distribution Loss Adjustment Factor (4 year average)				1.0535

Total Utility Loss Adjustment Factor

Supply Facility Loss Factor	1.024
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW	1.0535
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0430

TOTAL LOSS FACTOR

Total Loss Factor - Secondary Metered Customer < 5,000kW	1.0788
Total Loss Factor - Primary Metered Customer < 5,000kW	1.0680

Retail Transmission Adjustment Calculations

In order to comply with the Board's rate order "Ontario Uniform Transmission Rate Order, EB-2007-0759: effect on Distributor Retail Transmission Rates", Westario notes that on May 30, 2008, Hydro One Networks Inc. (Hydro One) filed an application before the Ontario Energy Board (the Board) to adjust uniform transmission rates (EB-2008-0113) effective January 1, 2009. Hydro One stated that the requested rates would result in a 9.2% average increase when applied to the uniform transmission rates. This application is presently before the Board and the Board has not reached any decision in this regard. Hydro One Networks is also expected to file a cost of service application in August 2008, which is a separate proceeding that could affect its final rates. Westario has not made any proposed changes to the Retail Transmission Rates in this application pending the Board's decision on Hydro One Networks Application regarding the proposed increase in retail transmission rates.

Determination of Commodity Price

For the 2008 Bridge Year and the 2009 Test Year, the Applicant has projected a price of \$0.05450 per kWh for the price of Electricity (Commodity). This price was determined using the 'Regulated Price Plan Price Report – May 1, 2008 to April 30, 2009' issued by the Ontario Energy Board on April 11, 2008. An excerpt from the report as found from Page *iii* of the Executive Summary is as follows:

Table ES-1: Average RPP Supply Cost Summary (for the 12 months from May 1, 2008)

RPP Supply Cost Summary

for the period from May 1, 2008 through April 30, 2009

Forecast Wholesale Electricity Price	\$60.72
Load-Weighted Price for RPP Consumers (\$ / MWh)	\$65.57
Impact of the Global Adjustment (\$ / MWh)	+ (\$1.11)
Impact of the OPG Non-prescribed Asset Rebate (\$ / MWh)	+ (\$7.44)
Adjustment to Address Bias Towards Unfavourable Variance (\$ / MWh)	+ \$1.00
Adjustment to Clear Existing Variance (\$ / MWh)	+ (\$3.52)
Average Supply Cost for RPP Consumers (\$ / MWh)	= \$54.50

Tax Calculations Overview

The applicant has completed the 2008 Bridge Year and 2009 Test Year PILS calculation consistent with the methodology of the 2006 EDR process. The PILS model attached as Exhibit 4, Tab 3, Schedule 2, has been provided by 'ERA'. The attached model has been reviewed by the applicant's external auditor to ensure that the current and proposed tax rates have been applied and that the amount of PILS calculated appears reasonable.

PILs

The results of the calculation of the PILs expense provided by ERA's PILs Model for the 2008 Bridge Year and 2009 Test Year are presented on the following tables which are provided as attachments to this section:

- Undepreciated Capital Costs Table
- Cumulative Eligible Capital Table
- Interest Expense Table
- Loss Carry forward Table
- Reserve Balances Table
- Taxable Income Table
- Capital Tax Table
- Total PILS Expense Table

[illegible]

1 of 5

[illegible]

2 of 5

Class	Description	Reduced UCC	Rate %	2008 CCA	UCC 31 Dec/08
1	Distribution System - post 1987	11,494,426	4.0%	459,777	11,034,649
2	Distribution System - pre 1988	5,909,904	6.0%	354,594	5,555,310
8	General Office/Stores Equip	689,470	20.0%	137,894	583,256
10	Computer Hardware/ Vehicles	755,414	30.0%	226,624	623,740
10.1	Certain Automobiles		30.0%		
12	Computer Software	21,087	100.0%	21,087	
13.1	Leasehold Improvement # 1		25 years		
13.2	Leasehold Improvement # 2		4 years		
13.3	Leasehold Improvement # 3				
13.4	Leasehold Improvement # 4				
14	Franchise		6 years		
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs		8.0%		
43.1	Certain Energy-Efficient Electrical Generating Equipment		30.0%		
45	Computers & Systems Software acq'd post Mar 22/04	16,062	45.0%	7,228	8,834
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)		30.0%		
47	Distribution System post Feb 22/05	7,535,768	8.0%	602,861	8,002,007
1	Distribution System - post 1987	2,370,473	6.0%	142,228	2,228,245
50		40,154	55.0%	22,085	36,969
			55.0%		
	TOTAL	28,832,758		1,974,379	28,073,009

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[illegible]

4 of 5

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P2 Cumulative Eligible Capital (CEC)

	2008		2009	
CEC Opening Balance ¹		1,177,170		1,094,768
Eligible Capital Property (ECP) Acquisitions				
Other Adjustments				
Subtotal	x 3/4 =		x 3/4 =	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after December 20, 2002	x 1/2 =		x 1/2 =	
Amount transferred on amalgamation or wind-up of subsidiary				
Subtotal before deductions		1,177,170		1,094,768
ECP Dispositions (net)				
Other Adjustments				
Subtotal	x 3/4 =		x 3/4 =	
Balance before tax deduction		1,177,170		1,094,768
Tax Deduction	Rate: 7.0%	82,402	Rate: 7.0%	76,634
CEC Ending Balance		<u>1,094,768</u>		<u>1,018,134</u>

¹ 2008 amount per ending balance on Schedule 10 of 2007 corporate tax return

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P3 Interest Expense

	2008	2009
Deemed Interest Expense (A)	683,993	1,086,808
3900-Interest Expense	813,450	842,083
Add: Capitalized Interest (USA #6040)		
Add: Capitalized Interest (USA #6042)		
Less: non-debt interest expense (USA #6035)	(38,100)	(40,000)
Total Interest Projected (B)	775,350	802,083
Excess Interest Expense	91,357	

Enter credit to P&L as positive number

Enter credit to P&L as positive number

Enter other adjustments for tax purposes

(B) less (A); if negative: zero

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P4 Loss Carry-Forward (LCF)

	Balance 31 Dec/07 ¹	Less: Non- Distribution Portion	Utility Balance 31 Dec/07	2008	2009
Non-Capital LCF:					
Opening Balance					
Application of LCF to reduce taxable income					
Ending Balance					
Net Capital LCF:					
Opening Balance					
Application of LCF to reduce taxable capital gains					
Ending Balance					

¹ per Schedule 7-1 of 2007 corporate tax return

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P5 Reserve Balances

	Balance 31 Dec/07 ¹	Less: Non- Distribution Portion	Utility Balance 31 Dec/07	Changes (+ / -) in 2008	Balance 31 Dec/08	Changes (+ / -) in 2009	Balance 31 Dec/09
Capital Gains Reserves ss.40(1)							
Tax Reserves not deducted for book purposes:							
Reserve for doubtful accounts ss. 20(1)(l)							
Reserve for goods and services not delivered ss. 20(1)(m)							
Reserve for unpaid amounts ss. 20(1)(n)							
Debt & Share Issue Expenses ss. 20(1)(e)							
TOTAL							
Accounting Reserves not deducted for tax purposes:							
General Reserve for Inventory Obsolescence (non-specific)							
General reserve for bad debts							
Accrued Employee Future Benefits:							
- Medical and Life Insurance							
- Short & Long-term Disability							
- Accumulated Sick Leave							
- Termination Cost							
- Other Post-Employment Benefits	296,913		296,913	45,937	342,850	4,800	347,650
Provision for Environmental Costs							
Restructuring Costs							
Accrued Contingent Litigation Costs							
Accrued Self-Insurance Costs							
Other Contingent Liabilities							
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)							
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)							
TOTAL	296,913		296,913	45,937	342,850	4,800	347,650

¹ per Schedule 13 of 2007 corporate tax return

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P6 Taxable Income

	T2 S1 line #	2006 EDR Approved			2008 Projection	2009 Projection ¹	2009 Test ¹
		Tax Return	Less: Non- Distribution Portion	Utility Only			
Income before PILs/Taxes (Accounting) ²		1,129,392		1,129,392	1,268,814	1,127,249	1,248,914
Additions:							
Interest and penalties on taxes	103	1,000		1,000	1,000	1,000	1,000
Amortization of tangible assets	104	1,271,615		1,271,615	1,720,456	1,829,713	1,829,713
Amortization of intangible assets	106						
Recapture of capital cost allowance from Schedule 8	107						
Gain on sale of eligible capital property from Schedule 10	108						
Income or loss for tax purposes- joint ventures or partnerships	109	3,653		3,653			
Loss in equity of subsidiaries and affiliates	110						
Loss on disposal of assets	111						
Charitable donations	112	365		365			
Taxable Capital Gains	113				3,750	250	250
Political Donations	114						
Deferred and prepaid expenses	116	150,000		150,000	1,188,450	763,316	763,316
Scientific research expenditures deducted on financial statements	118						
Capitalized interest	119						
Non-deductible club dues and fees	120						
Non-deductible meals and entertainment expense	121	10,000		10,000	10,000	10,000	10,000
Non-deductible automobile expenses	122						
Non-deductible life insurance premiums	123						
Non-deductible company pension plans	124						
Tax reserves beginning of year	125						
Reserves from financial statements- balance at end of year	126				342,850	347,650	347,650

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P6 Taxable Income

	T2 S1 line #	2006 EDR Approved			2008 Projection	2009 Projection ¹	2009 Test ¹
		Tax Return	Less: Non- Distribution Portion	Utility Only			
Income before PILs/Taxes (Accounting) ²		1,129,392		1,129,392	1,268,814	1,127,249	1,248,914
Soft costs on construction and renovation of buildings	127						
Book loss on joint ventures or partnerships	205						
Capital items expensed	206						
Debt issue expense	208						
Development expenses claimed in current year	212						
Financing fees deducted in books	216						
Gain on settlement of debt	220						
Non-deductible advertising	226						
Non-deductible interest	227						
Non-deductible legal and accounting fees	228						
Recapture of SR&ED expenditures	231						
Share issue expense	235						
Write down of capital property	236						
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237						
Actual Debt Interest					813,450	842,083	
Total Additions		1,436,633		1,436,633	4,079,956	3,794,012	2,951,929

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P6 Taxable Income

	T2 S1 line #	2006 EDR Approved			2008 Projection	2009 Projection ¹	2009 Test ¹
		Tax Return	Less: Non- Distribution Portion	Utility Only			
Income before PILs/Taxes (Accounting) ²		1,129,392		1,129,392	1,268,814	1,127,249	1,248,914
Deductions:							
Gain on disposal of assets per financial statements	401				7,500	500	500
Dividends not taxable under section 83	402						
Capital cost allowance from Schedule 8	403	1,096,493		1,096,493	1,974,379	2,002,304	2,002,304
Terminal loss from Schedule 8	404						
Cumulative eligible capital deduction from Schedule 10 CEC	405				82,402	76,634	76,634
Allowable business investment loss	406						
Deferred and prepaid expenses	409						
Scientific research expenses claimed in year	411						
Tax reserves end of year	413						
Reserves from financial statements - balance at beginning of year	414				296,913	342,850	342,850
Contributions to deferred income plans	416						
Book income of joint venture or partnership	305						
Equity in income from subsidiary or affiliates	306						
Expenses Capitalized for Regulatory Purposes	393	255,000		255,000			
Ontario Capital Tax paid	394				44,453	41,681	41,681
Excess Interest	395	26,822		26,822			
Deemed Debt Interest					683,993	1,086,808	
Total Deductions		1,378,315		1,378,315	3,089,639	3,550,777	2,463,969

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P6 Taxable Income

	T2 S1 line #	2006 EDR Approved			2008 Projection	2009 Projection ¹	2009 Test ¹
		Tax Return	Less: Non- Distribution Portion	Utility Only			
Income before PILs/Taxes (Accounting) ²		1,129,392		1,129,392	1,268,814	1,127,249	1,248,914
NET INCOME FOR TAX PURPOSES		1,187,710		1,187,710	2,259,131	1,370,484	1,736,874
Charitable donations from Schedule 2		365		365			
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)							
Non-capital losses of preceding taxation years from Schedule 4							
Net-capital losses of preceding taxation years from Schedule 4							
Limited partnership losses of preceding taxation years from Schedule 4							
TAXABLE INCOME		1,187,345		1,187,345	2,259,131	1,370,484	1,736,874

¹ = "Earnings before Tax" (sheet E1); = "Earnings before Tax" (sheet E2); = "Deemed Return On Equity" (sheet E3)

² 'Projection' = 'Earnings before Tax' (sheets E1 & E2); 'Test' = Deemed Return On Equity (sheet E3)

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P7 Capital Taxes

Rates and exemptions from sheet Y1

	2008	2009	
OCT (Ontario Capital Tax):			
Rate Base	32,256,716	33,524,934	'Calculated Value' from sheet E3
Less: Exemption	<u>12,500,000</u>	<u>15,000,000</u>	
Deemed Taxable Capital	19,756,716	18,524,934	
Tax Rate	0.225%	0.225%	
OCT payable	44,453	41,681	
Federal LCT (Large Corporations Tax):			
Rate Base	32,256,716	33,524,934	
Less: Exemption	<u>50,000,000</u>	<u>50,000,000</u>	
Deemed Taxable Capital			
Tax Rate			
LCT payable			

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P8 Total PILs Expense

	2008 Projection	2009 Projection ¹	2009 Test ¹	
Regulatory Taxable Income	2,259,131	1,370,484	1,736,874	from sheet P6
Combined Income Tax Rate	33.50%	30.26%	33.00%	"t" (from sheet Y1)
Total Income Taxes	756,809	414,755	573,168	
Investment & Miscellaneous Tax Credits				Input amounts
Income Tax Payable	<u>756,809</u>	<u>414,755</u>	<u>573,168</u>	"i"
Large Corporations Tax (LCT)				from sheet P7
Ontario Capital Tax (OCT)	44,453	41,681	41,681	from sheet P7
Grossed-up Income Tax			855,475	= i / (1 - t)
Grossed-up LCT				= LCT / (1 - t)
Total PILs Expense	801,261	456,436	897,156	Enter these results on sheet E4

¹ 'Projection' per existing distribution rates; 'Test' based on proposed revenue requirement

Capital Cost Allowance (CCA)

Details of the CCA is provided in Exhibit 4, Tab 3, Schedule 2.

1 **Federal T2 and Ontario CT23 tax returns**

2

3 Attached are signed copies of the 2007 T2 and CT23 tax returns.

4

Canada Revenue
AgencyAgence du revenu
du Canada

T2 CORPORATION INCOME TAX RETURN

200

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec, Ontario, 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 services office or 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* (T4012).

055 Do not use this area

Identification

Business Number (BN) **001** 86590 9790 RC0001**Corporation's name****002** Westario Power Inc.Has the corporation changed its name since the last time you filed your T2 return? **003** 1 Yes ☐ 2 No ☒If **yes**, do you have a copy of the articles of amendment? (**Do not submit**) **004** 1 Yes ☐ 2 No ☐**Address of head office**Has this address changed since the last time you filed your T2 return? **010** 1 Yes ☐ 2 No ☒(If **yes**, complete lines 011 to 018)**011** 24 Eastridge Road**012** RR 2

City Province, territory, or state

015 Walkerton**016** ON

Country (other than Canada) Postal code/Zip code

017 **018** NOG 2V0**Mailing address** (if different from head office address)Has this address changed since the last time you filed your T2 return? **020** 1 Yes ☐ 2 No ☒(If **yes**, complete lines 021 to 028)**021** c/o**022** 24 Eastridge Road**023** RR 2

City Province, territory, or state

025 Walkerton**026** ON

Country (other than Canada) Postal code/Zip code

027 **028** NOG 2V0**Location of books and records**Has the location of books and records changed since the last time you filed your T2 return? **030** 1 Yes ☐ 2 No ☒(If **yes**, complete lines 031 to 038)**031** 24 Eastridge Road**032** RR 2

City Province, territory, or state

035 Walkerton**036** ON

Country (other than Canada) Postal code/Zip code

037 **038** NOG 2V0**040** Type of corporation at the end of the tax year1 ☒ Canadian-controlled private corporation (CCPC) 4 ☐ Corporation controlled by a public corporation2 ☐ Other private corporation 5 ☐ Other corporation (specify, below)3 ☐ Public corporationIf 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 Tax year-end
060 2007-01-01 **061** 2007-12-31
YYYY MM DD YYYY MM DDHas there been an acquisition of control to which subsection 249(4) applies since the previous tax year? **063** 1 Yes ☐ 2 No ☒If **yes**, provide the date control was acquired **065** _____
YYYY MM DDIs the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? **066** 1 Yes ☐ 2 No ☒Is the corporation a professional corporation that is a member of a partnership? **067** 1 Yes ☐ 2 No ☒Is this the first year of filing after:
Incorporation? **070** 1 Yes ☐ 2 No ☒
Amalgamation? **071** 1 Yes ☐ 2 No ☒If **yes**, complete lines 030 to 038 and attach Schedule 24.Has there been a wind-up of a subsidiary under section 88 during the current tax year? **072** 1 Yes ☐ 2 No ☒
If **yes**, complete and attach Schedule 24.Is this the final tax year before amalgamation? **076** 1 Yes ☒ 2 No ☐Is this the final return up to dissolution? **078** 1 Yes ☐ 2 No ☒Is the corporation a resident of Canada?
080 1 Yes ☒ 2 No ☐ If **no**, give the country of residence on line 081 and **complete and attach** Schedule 97.**081** _____Is the non-resident corporation claiming an exemption under an income tax treaty? **082** 1 Yes ☐ 2 No ☒If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085 1 ☐ Exempt under paragraph 149(1)(e) or (l)
2 ☐ Exempt under paragraph 149(1)(j)
3 ☐ Exempt under paragraph 149(1)(t)
4 ☐ Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

Attachments**Financial statement information:** Use GIFI schedules 100, 125, and 141.**Schedules** – Answer the following questions. For each Yes response, **attach** to the T2 return the schedule that applies.

	Yes	Schedule
Is the corporation related to any other corporations?	150 ☒	9
Is the corporation an associated CCPC?	160 ☒	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161 ☐	49
Does the corporation have any non-resident shareholders?	151 ☐	19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162 ☐	11
If you answered yes to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163 ☐	44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164 ☐	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165 ☐	15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166 ☐	T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167 ☐	T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168 ☐	22
Did the corporation have any foreign affiliates during the year?	169 ☐	25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal <i>Income Tax Regulations</i> ?	170 ☐	29
Has the corporation had any non-arm's length transactions with a non-resident?	171 ☐	T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173 ☒	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172 ☐	
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201 ☒	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202 ☒	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203 ☒	3
Is the corporation claiming any type of losses?	204 ☐	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205 ☐	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206 ☒	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207 ☒	7
Does the corporation have any property that is eligible for capital cost allowance?	208 ☒	8
Does the corporation have any property that is eligible capital property?	210 ☒	10
Does the corporation have any resource-related deductions?	212 ☐	12
Is the corporation claiming reserves of any kind?	213 ☐	13
Is the corporation claiming a patronage dividend deduction?	216 ☐	16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217 ☐	17
Is the corporation an investment corporation or a mutual fund corporation?	218 ☐	18
Was 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

Attachments – continued from page 2

	Yes	Schedule
Is the corporation subject to Part XIII.1 tax?	255 ☐	92 *
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

* We do not print this schedule.

Additional information

Is the corporation inactive?	280	1 Yes ☐	2 No ☒
Has the major business activity changed since the last return was filed? (enter yes for first-time filers)	281	1 Yes ☐	2 No ☒
What is the corporation's major business activity?	282		
(Only complete if yes was entered at line 281)			
If the major business activity involves the resale of goods, show whether it is wholesale or retail	283	1 Wholesale ☐	2 Retail ☐
Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.	284	Hydro Services	285 100.000 %
	286		287 %
	288		289 %
Did the corporation immigrate to Canada during the tax year?	291	1 Yes ☐	2 No ☒
Did the corporation emigrate from Canada during the tax year?	292	1 Yes ☐	2 No ☒

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFL.	300	2,969,103	A
Deduct: Charitable donations from Schedule 2	311	11,580	
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	11,580	B
	Subtotal (amount A minus amount B) (if negative, enter "0")	2,957,523	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355		D
Taxable income (amount C plus amount D)	360	2,957,523	
Income exempt under paragraph 149(1)(t)	370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 minus line 370)		2,957,523	Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724.

Small business deduction**Canadian-controlled private corporations (CCPCs) throughout the tax year**

Income from active business carried on in Canada from Schedule 7	400	2,952,489	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 from Part I tax	405	2,957,523	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 2005 and in 2006	=	1
		Number of days in the tax year	365	
400,000	x	Number of days in the tax year after 2006	365	400,000 2
		Number of days in the tax year	365	
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 ***	28,330	D	=	1,007,289	E
								11,250

Reduced business limit (amount C minus amount E) (if negative, enter "0")	425	F

Small business deductionAmount A, B, C,
or F whichever
is the least

x	Number of days in the tax year before January 1, 2008	365	x	16 %	=	5
		Number of days in the tax year	365			

Amount A, B, C,
or F whichever
is the least

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	_____	x	17 %	=	_____	6
			Number of days in the tax year	365					

Amount A, B, C,
or F whichever
is the least

Amount A, B, C, or F whichever is the least	_____	x	Number of days in the tax year after December 31, 2008 _____	x	17 %	=	_____	7
			Number of days in the tax year 365					

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 2005	x	3 %	=	I
		Number of days in the tax year	365			

Amount H	x	Number of days in the tax year in 2006	x	5 %	=	J
		Number of days in the tax year	365			

Amount H	x	Number of days in the tax year in 2007	365	x	7 %	=	K
		Number of days in the tax year	365				

Resource deduction – total of amounts I, J and K	438	L

Enter amount L on line 10.

Refundable portion of Part I tax**Canadian-controlled private corporations throughout the tax year**

Aggregate investment income **440** 16,614 x 26 2 / 3 % = ... 4,430 A
(from Schedule 7)

Foreign non-business income tax credit from line 632

Deduct:

Foreign investment income **445** x 9 1 / 3 % = ...
(from Schedule 7) (if negative, enter "0") ►

Amount A **minus** amount B (if negative, enter "0") 4,430 C

Taxable income from line 360 2,957,523

Deduct:

Amount from line 400, 405, 410, or 425, whichever is the least

Foreign non-business
income tax credit

from line 632 x 25 / 9 = ...

Foreign business

income tax credit

from line 636 x 3 = ...

2,957,523

x 26 2 / 3 % = 788,673 D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780) 656,475

Deduct: Corporate surtax from line 600 33,124

Net amount 623,351 ► 623,351 E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least **450** 4,430 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**

..... ►

Add the total of:

Refundable portion of Part I tax from line 450 above 4,430

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**

4,430 ► 4,430 H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H **485** 4,430

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 3 461,053 x 1 / 3 153,684 I

Refundable dividend tax on hand at the end of the tax year from line 485 above 4,430 J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784) 4,430

Part I tax**Base amount of Part I tax** – taxable income (line 360 or amount Z, whichever applies) multiplied by 38.00 % **550** 1,123,859 A**Corporate surtax calculation**Base amount from line A above 1,123,859 1**Deduct:**10 % of taxable income (line 360 or amount Z, whichever applies) 295,752 2Investment corporation deduction from line 620 below 3 3Federal logging tax credit from line 640 below 4 4Federal qualifying environmental trust tax credit from line 648 below 5 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 c
(line A **plus** lines C and D **minus** line F)Total of lines 2 to 6 295,752 7Net amount (line 1 **minus** line 7) 828,107 8**Corporate surtax***Line 8 828,107 × $\frac{\text{Number of days in the tax year before January 1, 2008}}{\text{Number of days in the tax year}}$ $\frac{365}{365}$ × 4 % = **600** 33,124 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 16,614 iTaxable income from line 360 2,957,523**Deduct:**Amount from line 400, 405, 410, or 425, whichever is the least 2,957,523 ▶ 2,957,523 iiNet amount 2,957,523 ▶ 2,957,523 ii**Refundable tax on CCPC's investment income** – 6 2 / 3 % of whichever is less: amount i or ii **604** 1,108 DSubtotal (**add** lines A, B, C, and D) 1,158,091 E**Deduct:**Small business deduction from line 430 608 295,752 9Federal tax abatement 616Manufacturing and processing profits deduction from Schedule 27 620Investment corporation deduction 624(taxed capital gains **624**)Additional deduction – credit unions from Schedule 17 628Federal foreign non-business income tax credit from Schedule 21 632Federal foreign business income tax credit from Schedule 21 636Resource deduction from line 438 638 205,864 10General tax reduction for CCPCs from amount L 639General tax reduction from amount V 640Federal logging tax credit from Schedule 21 644Federal political contribution tax credit 646Federal political contributions **646** Federal qualifying environmental trust tax credit 648Investment tax credit from Schedule 31 652Subtotal 501,616 ▶ 501,616 F**Part I tax payable** – Line E **minus** line F 656,475 G

Enter amount G on line 700.

Summary of tax and credits**Federal tax**

Part I tax payable	700	656,475
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	

Add provincial or territorial tax:Total federal tax **656,475**Provincial or territorial jurisdiction **750** Ontario

(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Québec, Ontario, and Alberta) **760**Provincial tax on large corporations (New Brunswick and Nova Scotia) **765**Total tax payable **770** **656,475** A**Deduct other credits:**

Investment tax credit refund from Schedule 31	780	
Dividend refund	784	4,430
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** **652,045**Total credits **890** **656,475** BRefund code **894** Overpayment

Balance (line A minus line B)

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 numberIf 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**

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** Milne**951** Lisa**954** Controller

Last name in block letters

First name in block letters

Position, office, or rank

I 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 2008/06/24
Date (yyyy/mm/dd)

Signature of the authorized signing officer of the corporation

956 (519) 507-6937
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****990** 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.1 English / Anglais ☒ 2 Français / French ☐

Schedule of Instalment Remittances

Name of corporation contact _____
Telephone number _____

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Instalments	652,045
Total amount of instalments claimed (carry the result to line 840 of the T2 Return)		652,045 A
Total instalments credited to the taxation year per T9		652,045 B

Transfer

Account number	Taxation year end	Amount	Effective interest date	Description
From:				
To:				
From:				
To:				
From:				
To:				
From:				
To:				
From:				
To:				

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GENERAL INDEX OF FINANCIAL INFORMATION – GIF1

Form identifier 100

Name of corporation	Business Number	Tax year end Year Month Day
Westario Power Inc.	86590 9790 RC0001	2007-12-31

Balance sheet information

Account	Description	GIFI	Current year	Prior year
Assets				
	Total current assets	1599 +	10,039,800	10,390,288
	Total tangible capital assets	2008 +	34,379,989	30,202,050
	Total accumulated amortization of tangible capital assets	2009 –	8,811,339	7,248,845
	Total intangible capital assets	2178 +	2,214,322	2,214,322
	Total accumulated amortization of intangible capital assets	2179 –		
	Total long-term assets	2589 +	1,751,548	3,839,156
	* Assets held in trust	2590 +		
	Total assets (mandatory field)	2599 =	39,574,320	39,396,971

Liabilities				
	Total current liabilities	3139 +	7,048,467	8,536,877
	Total long-term liabilities	3450 +	13,646,890	12,475,144
	* Subordinated debt	3460 +		
	* Amounts held in trust	3470 +		
	Total liabilities (mandatory field)	3499 =	20,695,357	21,012,021

Shareholder equity				
	Total shareholder equity (mandatory field)	3620 +	18,878,963	18,384,950

	Total liabilities and shareholder equity	3640 =	39,574,320	39,396,971

Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849 =	4,814,244	4,320,231

* Generic item

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GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year end Year Month Day
Westario Power Inc.	86590 9790 RC0001	2007-12-31

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 +	40,642,424	39,844,604
	Cost of sales	8518 –	32,961,642	32,631,318
	Gross profit/loss	8519 =	7,680,782	7,213,286
	Cost of sales	8518 +	32,961,642	32,631,318
	Total operating expenses	9367 +	6,184,716	4,795,898
	Total expenses (mandatory field)	9368 =	39,146,358	37,427,216
	Total revenue (mandatory field)	8299 +	40,642,424	39,844,604
	Total expenses (mandatory field)	9368 –	39,146,358	37,427,216
	Net non-farming income	9369 =	1,496,066	2,417,388

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 =	1,496,066	2,417,388

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 –	1,052,000	1,245,000
	Deferred income tax provision	9995 –	-511,000	-360,824
	Net income/loss after taxes and extraordinary items (mandatory field)	9999 =	955,066	1,533,212

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Corporation's name	Business Number	Tax year end Year Month Day
Westario Power Inc.	86590 9790 RC0001	2007-12-31

- This schedule should be completed from the perspective of the person who prepared or reported on the **financial statements**. This person is referred to as the "accounting practitioner", in this schedule.
- For more information, see RC4088, *Guide to the General Index of Financial Information (GIFI) for Corporations* and T4012, *T2 Corporation – Income Tax Guide*.
- Attach a copy of this schedule, along with any Notes to the financial statements, to the GIFI.

Part 1 – Accounting practitioner information

Does the accounting practitioner have a professional designation? **095** 1 Yes ☒ 2 No ☐

Is the accounting practitioner connected* with the corporation? **097** 1 Yes ☐ 2 No ☒

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note

If the accounting practitioner does not have a professional designation **or** is connected with the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4.

Part 2 – Type of involvement

Choose the option that represents the highest level of involvement of the accounting practitioner: **198**

Completed an auditor's report	1	☐
Completed a review engagement report	2	☐
Conducted a compilation engagement	3	☒

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement** above, answer the following question:

Has the accounting practitioner expressed a reservation? **099** 1 Yes ☐ 2 No ☐

Part 4 – Other information

Were notes to the financial statements prepared? **101** 1 Yes ☒ 2 No ☐

If Yes, complete lines 102 to 107 below:

Are any values presented at other than cost? **102** 1 Yes ☐ 2 No ☒

Has there been a change in accounting policies since the last return? **103** 1 Yes ☐ 2 No ☒

Are subsequent events mentioned in the notes? **104** 1 Yes ☐ 2 No ☒

Is re-evaluation of asset information mentioned in the notes? **105** 1 Yes ☐ 2 No ☒

Is contingent liability information mentioned in the notes? **106** 1 Yes ☐ 2 No ☒

Is information regarding commitments mentioned in the notes? **107** 1 Yes ☐ 2 No ☒

Does the corporation have investments in joint venture(s) or partnership(s)? **108** 1 Yes ☐ 2 No ☒

If Yes, complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)? **109** 1 Yes ☐ 2 No ☐

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Corporation's name	Business Number	Tax year end Year Month Day
Westario Power Inc.	86590 9790 RC0001	2007-12-31

- 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 955,066 A

Add:

Provision for income taxes – current	101	1,052,000	
Provision for income taxes – deferred	102	-511,000	
Interest and penalties on taxes	103	34,332	
Amortization of tangible assets	104	1,562,492	
Charitable donations and gifts from Schedule 2	112	11,580	
Taxable capital gains from Schedule 6	113	16,614	
Deferred and prepaid expenses	116	1,219,397	
Non-deductible meals and entertainment expenses	121	5,125	
Subtotal of additions		3,390,540	3,390,540

Other additions:**Miscellaneous other additions:**

600 Capital tax expensed in f/s	290	56,250	
602 Swap Valuation	292	446,464	
Subtotal of other additions	199	502,714	502,714
Total additions	500	3,893,254	3,893,254

Deduct:

Gain on disposal of assets per financial statements	401	33,226	
Capital cost allowance from Schedule 8	403	1,474,269	
Cumulative eligible capital deduction from Schedule 10	405	84,735	
Subtotal of deductions		1,592,230	1,592,230

Other deductions:**Miscellaneous other deductions:**

700 Capital tax paid	390	61,323	
701 Carrying charges and other expenses deducted for tax	391	225,664	
Total	394		
Subtotal of other deductions	499	286,987	286,987
Total deductions	510	1,879,217	1,879,217

Net income (loss) for income tax purposes – enter on line 300 of the T2 return **2,969,103**

* For reference purposes only

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SCHEDULE 2

CHARITABLE DONATIONS AND GIFTS

Name of corporation	Business Number	Tax year-end Year Month Day
Westario Power Inc.	86590 9790 RC0001	2007-12-31

- 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	11,580
	Subtotal 11,580
	Add: Total donations of less than \$100 each
	Total donations in current tax year 11,580

	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 11,580		
Subtotal (line 250 plus line 210)	11,580	11,580	11,580
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)	255		
Total charitable donations available	11,580 A	11,580	11,580
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 11,580	11,580	11,580
Charitable donations closing balance	280		

Amounts carried forward – Charitable donations

Year of origin:		Federal	Quebec	Alberta
1 st prior year	2006			
2 nd prior year	2005			
3 rd prior year	2004			
4 th prior year	2003			
5 th prior year	2002			
6 th 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 %		2,226,827	B
Taxable capital gains arising in respect of gifts of capital property included in Part 1 **	225		C
Taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01)	227		D
The amount of the recapture of capital cost allowance in respect of charitable gifts	230		
Proceeds of disposition, less outlays and expenses **		E	
Capital cost **		F	
Amount E or F, whichever is less	235		
Amount on line 230 or 235, whichever is less			G
Subtotal (add amounts C, D, and G)			H
Amount H multiplied by 25 %			I
Subtotal (amount B plus amount I)		2,226,827	J
Maximum allowable deduction for charitable donations (enter amount A from Part 1, amount J, or net income for tax purposes, whichever is less)		11,580	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
1 st prior year	2006			
2 nd prior year	2005			
3 rd prior year	2004			
4 th prior year	2003			
5 th prior year	2002			
6 th 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
1 st prior year	2006			
2 nd prior year	2005			
3 rd prior year	2004			
4 th prior year	2003			
5 th prior year	2002			
6 th 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
Cost of gifts of medicine	601	2	2
Subtotal (line 1 minus line 2)		3	3
Line 3 multiplied by 50 %		4	4
Eligible amount of gifts	600	5	5
Federal			
A _____ x $\left(\frac{B}{C} \right)$ = Additional deduction for gifts of medicine for the current year	610		
Quebec			
A _____ x $\left(\frac{B}{C} \right)$ = Additional deduction for gifts of medicine for the current year			
Alberta			
A _____ x $\left(\frac{B}{C} \right)$ = 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)			
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
1 st prior year	2006			
2 nd prior year	2005			
3 rd prior year	2004			
4 th prior year	2003			
5 th prior year	2002			
6 th prior year *	2002			
Total				

* These donations expired in the current year.

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 Westario Power Holdings Inc.	89276 4416 RC0001	2007-12-31	461,053
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 461,053

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** 461,053

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** 461,053

Other dividends paid in the taxation year (total of 510 to 540)

Total dividends paid in the taxation year **500** 461,053

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 461,053

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SCHEDULE 6

SUMMARY OF DISPOSITIONS OF CAPITAL PROPERTY

Name of corporation	Business Number	Tax year-end Year Month Day
Westario Power Inc.	86590 9790 RC0001	2007-12-31

- For use by corporations that have disposed of capital property or claimed an allowable business investment loss, or both, in the tax year.
- Use this schedule to make a designation under paragraph 111(4)(e) of the federal *Income Tax Act*, if the control of the corporation has been acquired by a person or group of persons.

For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in the *T2 Corporation – Income Tax Guide*.**Designation under paragraph 111(4)(e) of the *Income Tax Act***

Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)?

050 1 Yes ☐ 2 No ☒ If Yes, attach a statement specifying which properties are subject to such a designation.**Part 1 – Shares**

No. of shares	Name of corporation	Class of shares	Date of acquisition YYYY/MM/DD	Proceeds of disposition	Adjusted cost base	Outlays and expenses (dispositions)	Gain (or loss) (column 120 less cols. 130 and 140)	Foreign source
100	105	106	110	120	130	140	150	
1								
Totals								

Total adjustment under subsection 112(3) of the ITA to all losses identified in Part 1 **160**Actual gain or loss from the disposition of shares (total of line 150 **plus** line 160) **A****Part 2 – Real estate – Do not include losses on depreciable property**

Municipal address 1 = Address 1 2 = Address 2 3 = City 4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code	Date of acquisition YYYY/MM/DD	Proceeds of disposition	Adjusted cost base	Outlays and expenses (dispositions)	Gain (or loss) (column 220 less cols. 230 and 240)	Foreign source
200	210	220	230	240	250	
1 Land		48,227	15,000		33,227	
2						
Totals		48,227	15,000		33,227	B

Part 3 – Bonds

Face value	Maturity date	Name of issuer	Date of acquisition YYYY/MM/DD	Proceeds of disposition	Adjusted cost base	Outlays and expenses (dispositions)	Gain (or loss) (column 320 less cols. 330 and 340)	Foreign source
300	305	307	310	320	330	340	350	
1								
Totals								C

Part 4 – Other properties – Do not include losses on depreciable property

Description	Date of acquisition YYYY/MM/DD	Proceeds of disposition	Adjusted cost base	Outlays and expenses (dispositions)	Gain (or loss) (column 420 less cols. 430 and 440)	Foreign source
400	410	420	430	440	450	
1						
Totals						D

Part 5 – Personal-use property (Do not include listed personal property)

Description	Date of acquisition YYYY/MM/DD	Proceeds of disposition	Adjusted cost base	Outlays and expenses (dispositions)	Gain only (column 520 less cols. 530 and 540)	Foreign source
500	510	520	530	540	550	
1						
Note: Losses are not deductible		Totals				E

Part 6 – Listed personal property

Description	Date of acquisition YYYY/MM/DD	Proceeds of disposition	Adjusted cost base	Outlays and expenses (dispositions)	Gain (or loss) (column 620 less cols. 630 and 640)	Foreign source
600	610	620	630	640	650	
1						
		Totals				
Note: Net listed personal property losses may only be applied against listed personal property gains					Subtract: Unapplied listed personal property losses from other years 655	
Amount from line 655 is from line 530 in Part 5 of Schedule 4					Net gains (or losses)	F

Part 7 – Determining allowable business investment losses**Property qualifying for and resulting in an allowable business investment loss**

Name of small business corporation	Shares, enter 1; debt, enter 2	Date of acquisition YYYY/MM/DD	Proceeds of disposition	Adjusted cost base	Outlays and expenses (dispositions)	(Loss)(column 920 less cols. 930 and 940)	Foreign source
900	905	910	920	930	940	950	
1							
Note: Properties listed in Part 7 should not be included in any other parts of Schedule 6		Totals					G

Allowable business investment losses Amount G _____ x 50 % = _____ **H**

Enter amount H on line 406 of Schedule 1

Part 8 – Determining capital gains or losses

Total of amounts A to F (do not include F if the amount is a loss)	33,227	I	Foreign source
Add:			
Capital gains dividend received in the year	875		J ☐
Capital gains reserve opening balance (from Schedule 13)	880		K
Subtotal (add amounts I, J, and K)	33,227	L	
Deduct: Capital gains reserve closing balance (from Schedule 13)	885		M
Capital gains or losses (amount L minus amount M)	890	33,227	

Part 9 – Determining taxable capital gains and total capital losses

Capital gains or losses (amount from line 890 above) 33,227 N

Deduct the following gains that are included in the amount N:

Gain on donation of a share, debt obligation, or right listed on
a designated stock exchange and other amounts under
paragraph 38(a.1) of the *Income Tax Act*

realized prior to May 2, 2006 x 50 % = O

Foreign
source
☐

realized after May 1, 2006 P

Foreign
source
☐

Subtotal: O plus P **895**

Gain on donation of ecologically sensitive land

realized prior to May 2, 2006 x 50 % = Q

Foreign
source
☐

realized after May 1, 2006 R

Foreign
source
☐

Subtotal: Q plus R **896**

Exempt portion of the gain on the donation of securities arising from the exchange
of a partnership interest under paragraph 38(a.3) as proposed in federal Bill C-50

Foreign
source
☐

R-2

Total: line 895 plus line 896 plus R-2

S

Amount N minus amount S 33,227 T

Total capital losses: If amount T is a loss, enter it on line 210 of Schedule 4

Taxable capital gains: If amount T is a gain, enter it on this line and multiply 33,227 x 50 % = 16,614 U

Enter amount U on line 113 of Schedule 1



CALCULATION OF AGGREGATE INVESTMENT INCOME AND ACTIVE BUSINESS INCOME

Name of corporation	Business Number	Tax year end Year Month Day
Westario Power Inc.	86590 9790 RC0001	2007-12-31

- 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		16,614	001	002 16,614	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)		16,614		16,614	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")		16,614		16,614	E
Total income from property (in box 32 include income from a specified investment business carried on in Canada other than income from a source outside Canada)					
	Taxable dividends				
	Other property income				
Total income from property			019	032	F
	Exempt income		029	042	G
	Amounts received from NISA Fund No. 2 (AGRI) that were included in computing the corporation's income for the year			052	H
	Taxable dividends deductible (total of Column F on Schedule 3)		049	062	I
	Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)		059	072	J
Total of amounts G, H, I, and J					K
Amount F minus amount K					L
Total of amount E plus amount L		16,614		16,614	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")		16,614	079 L	092 O 16,614	

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				Total income (loss) of partnership from an active business	Corporation's share of amount in column B
200				300	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)]	Corporation's income (loss) of the partnership (column C plus column D)	Number of days in the partnership's fiscal period	Prorated business limit (column C ÷ column B) × [business limit* × (column F ÷ 365)] (if column C is negative, enter "0")**	Column E minus column G (if negative, enter "0")	Lesser of columns E and G (if column E is negative, enter "0")
315	320	325	330		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			2,969,103	P
Deduct: Foreign business income after deducting related expenses*	500			
Taxable capital gains minus allowable capital loss – amount A minus amount B* (page 1)**		16,614		
Net property income = amount F minus amount G, H, and N* (page 1)				Q
Personal services business income after deducting related expenses*	520			
		16,614	▶	16,614
		Net amount	2,952,489	R
Deduct: Partnership income (line 450 above)				S
Income from active business carried on in Canada (enter on line 400 of the T2 return – if negative, enter "0")			2,952,489	T

* If negative, **add** instead of **subtracting**.

**This amount may only be negative to the extent of any allowable business investment losses.



CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Westario Power Inc.	86590 9790 RC0001	2007-12-31

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	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year)	3 Cost of acquisitions during the year (new property must be available for use)*	4 Net adjustments**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)***	7 Reduced undepreciated capital cost	8 CCA rate %	9 Recapture of capital cost allowance (line 107 of Schedule 1)	10 Terminal loss (line 404 of Schedule 1)	11 Capital cost allowance (column 7 multiplied by column 8; or a lower amount) (line 403 of Schedule 1)****	12 Undepreciated capital cost at the end of the year (column 6 plus column 7 minus column 11)
200		201	203	205	207	211		212	213	215	217	220
1	1	11,973,360			0		11,973,360	4	0	0	478,934	11,494,426
2	1		2,443,787		0	1,221,894	1,221,893	6	0	0	73,314	2,370,473
3	2	6,287,132			0		6,287,132	6	0	0	377,228	5,909,904
4	8	422,494			0		422,494	20	0	0	84,499	337,995
5	47	4,580,392	2,346,570		0	1,173,285	5,753,677	8	0	0	460,294	6,466,668
Total		23,263,378	4,790,357			2,395,179	25,658,556				1,474,269	26,579,466

- * 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.



RELATED AND ASSOCIATED CORPORATIONS

Name of corporation Westario Power Inc.	Business Number 86590 9790 RC0001	Tax year end Year Month Day 2007-12-31

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.	Westario Power Services Inc.		89276 4614 RC0001	3					
2.	Westario Power Holdings Inc.		89276 4416 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.

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
Westario Power Inc.	86590 9790 RC0001	2007-12-31

- 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	1,210,495	A
Add:			
Cost of eligible capital property acquired during the taxation year	222		
Other adjustments	226		
Subtotal (line 222 plus line 226)		x 3 / 4 =	B
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228	x 1 / 2 =	C
amount B minus amount C (if negative, enter "0")			D
Amount transferred on amalgamation or wind-up of subsidiary	224		E
Subtotal (add amounts A, D, and E)	230	1,210,495	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 =	J
Cumulative eligible capital balance (amount F minus amount J) (if amount K is negative, enter "0" at line M and proceed to Part 2)		1,210,495	K
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business	249		
amount K		1,210,495	
less amount from line 249			
Current year deduction		1,210,495 x 7.00 % =	84,735 *
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)		84,735	L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")	300	1,125,760	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 2007

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? **075** 1 Yes ☐ 2 No ☒

	1 Names of associated corporations	2 Business Number of associated corporations	3 Asso- ciation code	4 Business limit for the year (before the allocation) \$	5 Percentage of the business limit %	6 Business limit allocated* \$
	100	200	300		350	400
1	Westario Power Inc.	86590 9790 RC0001	1	400,000	100.0000	400,000
2	Westario Power Services Inc.	89276 4614 RC0001	1	400,000		
3	Westario Power Holdings Inc.	89276 4416 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 $0.225\% \times (A - \$10,000,000)$ where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

*Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. In this case, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

**The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

***"Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.



Canada Revenue
Agency

Agence du revenu
du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Westario Power Inc.	86590 9790 RC0001	2007-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)		Business Number	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
100		200	300	350	400	500
1	Westario Power Holdings Inc.	89276 4416 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						



Ministry of Revenue

Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

2007

CT23 Corporations Tax and
Annual ReturnFor taxation years commencing
after December 31, 2004Corporations Tax Act – Ministry of Finance (MOF)
Corporations Information Act – Ministry of Government Services (MGS)

This form is a combination of the Ministry of Finance (MOF) **CT23 Corporations Tax Return** and the Ministry of Government Services (MGS) **Annual Return**. Page 1 is a common page required for both Returns. For tax purposes, depending on which criteria the corporation satisfies, it must complete either the **Exempt from Filing (EFF)** declaration on page 2 or file the **CT23 Return** on pages 3-17. Corporations that **do not** meet the EFF criteria but **do** meet the Short-Form criteria, may request and file the **CT23 Short-Form Return** (see page 2).

The **Annual Return** (common page 1 and MGS Schedule A on pages 18 and 19, and Schedule K on page 20) contains non-tax information collected under the authority of the *Corporations Information Act* for the purpose of maintaining a public database of corporate information. This return must be completed by Ontario share-capital corporations or Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

MGS Annual Return Required? (Not required if already filed or
Annual Return exempt. Refer to Guide) ☒ Yes ☐ No **Page 1 of 20**

Corporation's Legal Name (including punctuation) Westario Power Inc.			Ontario Corporations Tax Account No. (MOF) 1800342														
Mailing Address 24 Eastridge Road RR 2 Walkerton ON CA N0G 2V0			This Return covers the Taxation Year Start <table border="1"><tr><td>year</td><td>month</td><td>day</td></tr><tr><td>2007</td><td>01</td><td>01</td></tr></table> End <table border="1"><tr><td>year</td><td>month</td><td>day</td></tr><tr><td>2007</td><td>12</td><td>31</td></tr></table>			year	month	day	2007	01	01	year	month	day	2007	12	31
year	month	day															
2007	01	01															
year	month	day															
2007	12	31															
Has the mailing address changed since last filed CT23 Return? ☐ Yes	Date of Change	year month day	Date of Incorporation or Amalgamation <table border="1"><tr><td>year</td><td>month</td><td>day</td></tr><tr><td>2002</td><td>05</td><td>06</td></tr></table>			year	month	day	2002	05	06						
year	month	day															
2002	05	06															
Registered/Head Office Address 24 Eastridge Road RR 2 Walkerton ON CA N0G 2V0			Ontario Corporation No. (MGS) 1447793														
Location of Books and Records 24 Eastridge Road RR 2 Walkerton ON CA N0G 2V0			Canada Revenue Agency Business No. If applicable, enter 86590 9790 RC0001														
Name of person to contact regarding this CT23 Return Lisa Milne	Telephone No. (519) 507-6937	Fax No.	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 <table border="1"><tr><td>year</td><td>month</td><td>day</td></tr></table> Ceased <table border="1"><tr><td>year</td><td>month</td><td>day</td></tr></table>			year	month	day	year	month	day						
year	month	day															
year	month	day															
Former Corporation Name (Extra-Provincial Corporations only) ☒ Not Applicable (MGS)			☒ Not Applicable														
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).			Preferred Language / Langue de préférence ☒ English anglais ☐ French français														
If there is no change to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check (X) this box. Schedule(s) A and K are not required (MGS). ☒ No Change			Ministry Use 														

Certification (MGS)

I certify that all information set out in the **Annual Return** is true, correct and complete.

Name of Authorized Person (Print clearly or type in full)

Lisa Milne

Title ☐ Director ☐ Officer ☒ 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.**

Westario Power Inc.

1800342

2007-12-31

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

Please check applicable (X) box(es) and complete required information.

Type of corporation

1 ☒ 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 100 (nearest percent) %

- 2**
- 1 ☐ Family Farm corporation s.1(2)
- 2 ☐ Family Fishing corporation s.1(2)
- 3 ☐ Mortgage Investment corporation s.47
- 4 ☐ Credit Union s.51
- 5 ☐ Bank Mortgage subsidiary s.61(4)
- 6 ☐ Bank s.1(2)
- 7 ☐ Loan and Trust corporation s.61(4)
- 8 ☐ Non-resident corporation s.2(2)(a) or (b)
- 9 ☐ Non-resident corporation s.2(2)(c)
- 10 ☐ Mutual Fund corporation s.48
- 11 ☐ Non-resident owned Investment corporation s.49
- 12 ☐ Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)
- 14 ☐ Bare Trustee corporation
- 15 ☐ Branch of Non-resident s.63(1)
- 16 ☐ Financial institution prescribed by Regulation only
- 17 ☐ Investment Dealer
- 18 ☐ Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale
- 19 ☒ Hydro successor, municipal electrical utility or subsidiary of either
- 20 ☐ Producer and seller of steam for uses other than for the generation of electricity
- 21 ☐ Insurance Exchange s.74.4
- 22 ☐ Farm Feeder Finance Co-operative corporation
- 23 ☐ Professional corporation (incorporated professionals only)

☐ This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)

☐ Amended Return

☐ Taxation year end change – Canada Revenue Agency approval required

☐ Final taxation year up to dissolution (Note: for discontinued businesses, see guide.)

☒ Final taxation year before amalgamation

☐ The corporation has a floating fiscal year end

☐ There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario

☐ There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year

If checked, date control was acquired

year month day

☐ The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)

☐ First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)

☐ Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes No

☐ ☒ Was the corporation inactive throughout the taxation year?

☒ ☐ Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?

Are you requesting a refund due to:

☐ ☒ the Carry-back of a Loss?

☒ ☐ an Overpayment?

☐ ☒ a Specified Refundable Tax Credit?

☐ ☒ Are you a member of a Partnership or Joint Venture?

Complete if applicable

Ontario Retail Sales Tax Vendor
Permit no. (Use head office no.)

Ontario Employer Health Tax
Account no. (Use head office no.)

Specify major business activity

Allocation – If you carry on a business through a permanent establishment in a jurisdiction outside Ontario, you may allocate that portion of taxable income deemed earned in that jurisdiction to that jurisdiction (s.39) (Int.B. 3008).

DOLLARS ONLY

Net Income (loss) for Ontario purposes (per reconciliation schedule, page 15)	- - - - -	±	From	690	2,969,103	●
Subtract: Charitable donations	- - - - -	-		1	11,580	●
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		●
	From 715					
Net capital losses (page 16)	● x inclusion rate			50.000000	% =	-
Farm losses	- - - - -	-	From	724		●
Restricted farm losses	- - - - -	-	From	734		●
Limited partnership losses	- - - - -	-	From	754		●
Taxable Income (Non-capital loss)	- - - - -	=		10	2,957,523	●

Addition to taxable income for unused foreign tax deduction for federal purposes - - - - - + 11 ●

Adjusted Taxable Income 10 + 11 (if 10 is negative, enter 11) - - - - - = 20 2,957,523 ●

Taxable Income

From 10 (or 20 if applicable)	2,957,523 ● x 30	100.0000	% x 12.5 % x 33	÷ 73	365	= + 29	
							Ontario Allocation
From 10 (or 20 if applicable)	2,957,523 ● x 30	100.0000	% x 14 % x 34	365 ÷ 73	365	= + 32	414,053 ●
							Ontario Allocation
Income Tax Payable (before deduction of tax credits)	29 + 32	- - - - -				= 40	414,053 ●

Number of Days in Taxation Year

Days after Dec. 31, 2002 and before Jan. 1, 2004 Total Days

Days after Dec. 31, 2003 Total Days

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

If this section is not completed, the IDSBC will be denied.

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? (X)

☒ Yes ☐ No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))	- - - -	50	2,952,489 ●
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	+ 51	2,957,523 ●	
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		●
	=	2,957,523 ●	54 2,957,523 ●
Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1)	- - - - -	55	400,000 ●

Ontario Business Limit Calculation

320,000 x	31	÷ **	365	= + 46	
					●
400,000 x	34	365 ÷ **	365	= + 47	400,000 ●
Business Limit for Ontario purposes	46 + 47	= 44	400,000 ● x	48	100.0000 % = 45 400,000 ●
Income eligible for the IDSBC	- - - - -	From 30	100.0000 % x 56	400,000 ● = 60	400,000 ●
			***Ontario Allocation	Least of 50 , 54 or 45	

* **Note:** Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)

** **Note:** Adjust accordingly for a floating taxation year and use 366 for a leap year.

*** **Note:** Ontario Allocation for IDSBC purposes may differ from 30 if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).

continued on Page 5

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 56 400,000 .

Add: Adjustment for Surtax on Canadian-controlled private corporations

$$\frac{\text{From } 100}{34,000} \div \frac{\text{From } 30}{100.0000\%} \div \frac{\text{From } 78}{8.5000\%} = 121 \quad 400,000 .$$

*Ontario Allocation

Lesser of 56 or 121 - - - - - + 122 400,000 .

120 - 56 + 122 - - - - - = 130 .

Taxable Income - - - - - + From 10 2,957,523 .

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) - - - - - From 56 400,000 .

Add: Adjustments for Surtax on Canadian-controlled private corporations - - - - - + From 122 400,000 .

Subtract: Taxable Income 10 2,957,523 X Allocation % to jurisdictions outside Canada - - - - - 140 .

Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses - - - - - 141 16,614 .

10 - 56 + 122 - 140 - 141 - - - - - = 142 2,940,909 .

Claim**Number of Days in Taxation Year**Days after Dec. 31, 2002
and before Jan. 1, 2004

Total Days

$$\frac{143}{\text{Lesser of } 130 \text{ or } 142} \times \frac{\text{From } 30}{100.0000\%} \times 1.5\% \times \frac{33}{73} \div \frac{365}{365} = + 154 .$$

Ontario Allocation

Days after Dec. 31, 2003

Total Days

$$\frac{143}{\text{Lesser of } 130 \text{ or } 142} \times \frac{\text{From } 30}{100.0000\%} \times 2\% \times \frac{34}{73} \div \frac{365}{365} = + 156 .$$

Ontario Allocation

M&P claim for taxation year 154 + 156 - - - - - = 160 .

*** Note:** Ontario Allocation for M&P Credit purposes may differ from 30 if Taxable Income is allocated to foreign jurisdictions. See special rules (s.43(1))**Manufacturing and Processing Profits Credit for Electrical Generating Corporations**

= 161 .

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity

= 162 .

Credit for Foreign Taxes Paid (s.40)**Applies** if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). (Attach schedule)

- 170 .

Credit for Investment in Small Business Development Corporations (SBDC)**Applies** if you have an unapplied, previously approved credit from prior years' investments in new issues of equity shares in Small Business Development Corporations. Any unused portion may be carried forward indefinitely and applied to reduce subsequent years' income taxes. (Refer to the former *Small Business Development Corporations Act*)

Eligible Credit 175 .

Credit Claimed 180 .

Subtotal of Income Tax

40 - 70 + 100 - 110 - 160 - 161 - 162 - 170 - 180 - - - - = 190 414,053 .

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 OITC Claim Form *(Attach original Claim Form)* - - - - - + **Co-operative Education Tax Credit (CETC) (s.43.4)** *Applies* to employment of eligible students.Eligible Credit From CT23 Schedule 113 *(Attach Schedule 113)* - - - - - + **Ontario Film & Television Tax Credit (OFTTC) (s.43.5)***Applies* to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. Eligible Credit From of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* - - - - - + **Graduate Transitions Tax Credit (GTTC) (s.43.6)***Applies* to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005. Eligible Credit From CT23 Schedule 115 *(Attach Schedule 115)* - - - - - + **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 OBPTC Claim Form *(Attach both the original Claim Form and the Certificate of Eligibility)* - - + **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 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* - - - - - + **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 OBRITC Claim Form *(Attach original Claim Form)* - - - - - + **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 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* - - - - - + **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 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* - - - - - + **Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)***Applies* to qualifying expenditures in respect of eligible Canadian sound recordings.Eligible Credit From OSRTC Claim Form *(Attach both the original Claim Form and the Certificate of Eligibility)* - - + **Apprenticeship Training Tax Credit (ATTC) (s.43.13)***Applies* to employment of eligible apprentices. Eligible Credit From CT23 Schedule 114 *(Attach Schedule 114)* - - - - - + Other (specify) - - - - - + **Total Specified Tax Credits** + + + + + + + + + + + = **Specified Tax Credits** *Applied to reduce Income Tax* - - - - - = **Income Tax** - **OR Enter NIL if reporting Non-Capital Loss** *(amount cannot be negative)* - - - - =

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 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]	39,574,320 ●	
Total Revenue of the corporation	- - - - - + [241]		40,642,424 ●

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			
Westario Power Services Inc.	1800224	2007-12-31	+	243	4,498,669 ●	+	244	3,459,834 ●
Westario Power Holdings Inc.	1800222	2007-12-31	+	245	18,461,529 ●	+	246	1,135,873 ●
			+	247	●	+	248	●
Aggregate Total Assets	240 + 243 + 245 + 247, etc.	- - - - -	=	249	62,534,518 ●			
Aggregate Total Revenue	241 + 244 + 246 + 248, etc.	- - - - -	=	250	45,238,131 ●			

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	1,496,066 ●	X	From	30	100.0000 %	X	4 %	=	276	59,843 ●
					If negative, enter zero		Ontario Allocation								

[illegible]

Net CMT Payable	(If negative, enter Nil on Page 17.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	=	280	-354,210 ●

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	<u>190</u>	414,053.
	Gross CMT Payable	- - - - -	+	From	<u>276</u>	59,843.
	Subtract: Foreign Tax Credit for CMT purposes	- - - - -	-	From	<u>277</u>	.
	If <u>276</u> - <u>277</u> is negative, enter NIL in <u>290</u>		=		<u>59,843.</u>	▶ - <u>290</u> 59,843.
	Income Tax eligible for CMT Credit	- - - - -	=		<u>300</u>	354,210.

B.	Income Tax (after deduction of specified credits)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	+ From	230		414,053 ●
	Subtract: CMT credit used to reduce income taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	310		●
	Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	=	320		414,053 ●	
																							<i>Transfer to page 17</i>			

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.

Westario Power Inc.

1800342

2007-12-31

DOLLARS ONLY

Capital Tax (Refer to Guide and Int.B. 3011R)

If your corporation is a Financial Institution (s.58(2)), complete lines 480 and 430 on page 10 then proceed to page 13.

If your corporation is not a member of an associated group and/or partnership and the Gross Revenue and Total Assets as calculated on page 10 in 480 and 430 are both \$3,000,000 or less, your corporation is exempt from Capital Tax for the taxation year, except for a branch of a non-resident corporation. A corporation that meets these criteria should disregard all other Capital Tax items (including the calculation of Taxable Capital). Enter NIL in 550 on page 12 and complete the return from that point. All other corporations must compute their Taxable Capital in order to determine their Capital Tax payable.

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be

adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

Any Assets and liabilities of a corporation that are being utilized in a joint venture must be included along with the corporation's other Assets and liabilities when calculating its Taxable Paid-up Capital.

Special rules and rates apply to Non-Resident corporations (s.63, s.64 and s.69(3)).

Paid-up Capital of Non-resident: Paid-up capital employed in Canada of a non-resident subject to tax by virtue of s.2(2)(a) or 2(2)(b), and whose business is not carried on solely in Canada is deemed to be the greater of (1) taxable Income in Canada divided by 8 percent or (2) total assets in Canada minus certain indebtedness in accordance with the provisions of s.63(1)(a) (Int.B. 3010).

Paid-up Capital

Paid-up capital stock (Int.B. 3012R and 3015R)	- - - - -	+	350	14,064,719
Retained earnings (if deficit, deduct) (Int.B. 3012R)	- - - - -	+	351	4,814,244
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	- - - - -	+	352	
Loans and advances (Attach schedule) (Int.B. 3013R)	- - - - -	+	353	14,064,274
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	242,637
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	
Share of partnership(s) or joint venture(s) paid-up capital (Attach schedule(s)) (Int.B. 3017R)	- - - - -	+	362	
Subtotal	- - - - -	=	370	33,185,874
Subtract: Amounts deducted for income tax purposes in excess of amounts booked (Retain calculations. Do not submit.) (Int.B. 3012R)	- - - - -	-	371	670,418
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	32,515,456
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	32,515,456

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	39,574,320	•
Mortgages or other liabilities deducted from assets	- - - - -	+	421		•
Share of partnership(s)/joint venture(s) total assets (<i>Attach schedule</i>)	- - - - -	+	422		•
Subtract: Investment in partnership(s)/joint venture(s)	- - - - -	-	423		•
Total Assets as adjusted	- - - - -	=	430	39,574,320	•
Amounts in 360 and 361 (if deducted from assets)	- - - - -	+	440		•
Subtract: Amounts in 371, 372 and 381	- - - - -	-	441	670,418	•
Subtract: Appraisal surplus if booked	- - - - -	-	442		•
Add or Subtract: Other adjustments (specify on an attached schedule)	- - - - -	±	443		•
Total Assets	- - - - -	=	450	38,903,902	•

Investment Allowance (410 ÷ 450) × 390	- - - - -	Not to exceed 410	=	460	•
Taxable Capital 390 - 460	- - - - -		=	470	32,515,456 •

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)	- - -	480	40,642,424 •
Total Assets (as adjusted)	- - - - -	From 430	39,574,320 •

Calculation of Capital Tax for all Corporations except Financial Institutions**Note:** This version (2007) of the CT23 may only be used for a taxation year that commenced after December 31, 2004.

Financial Institutions use calculations on page 13.

Important:

- If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only Section A below.
- OR** If the corporation is **not** a member of an associated group and/or partnership, complete Section B below, then review only the Capital Tax calculations in Section C on page 11, selecting and completing the one specific subsection (e.g. C3) that applies to the corporation.
- OR** If the corporation is a member of an associated group and/or partnership, complete Section B below and Section D on page 11, and if applicable, complete Section E or Section F on page 12. Note: if the corporation is a member of a connected partnership, please refer to the CT23 Guide for additional instructions before completing the Capital Tax section.

SECTION A

This section applies only if the corporation is a family farm corporation, a family fishing corporation or a credit union that is not a Financial Institution (Int.B. 3018).

Enter NIL in 550 on page 12 and complete the return from that point.

SECTION B**B1.** Calculation of Taxable Capital Deduction (TCD)

		Number of Days in Taxation Year			
		Days after Dec. 31, 2004 and before Jan. 1, 2006	Total Days		
7,500,000	×	36	÷ 73 365	= +	501 •
		Days after Dec. 31, 2005 and before Jan. 1, 2007	Total Days		
10,000,000	×	37	÷ 73 365	= +	502 •
		Days after Dec. 31, 2006 and before Jan. 1, 2008	Total Days		
12,500,000	×	38 365	÷ 73 365	= +	504 12,500,000 •
		Days after Dec. 31, 2007	Total Days		
15,000,000	×	39	÷ 73 365	= +	505 •
Taxable Capital Deduction (TCD) 501 + 502 + 504 + 505				=	503 12,500,000 •

B2. This section applies to corporations to calculate the prorated capital tax rate.

Calculation of Capital Tax Rate

		Number of Days in Taxation Year			
		Days before Jan. 1, 2007	Total Days		
0.3 %	×	556	÷ 73 365	= +	511 %
		Days after Dec. 31, 2006 and before Jan. 1, 2009	Total Days		
0.285 %	×	557 365	÷ 73 365	= +	512 0.2850 %
Capital Tax Rate 511 + 512				=	516 0.2850 %

continued on Page 11

D2. Calculation Do not complete this calculation if ss.69(2.1) election is filed

Taxable Capital From 470 on page 10 - - - - - + From 470 32,515,456.

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

Westario Power Services Inc.	1800224	2007-12-31	+	531	4,149,900	●
Westario Power Holdings Inc.	1800222	2007-12-31	+	532	289,181	●
			+	533		●
Aggregate Taxable Capital	470 + 531 + 532 + 533, etc.	- - - - -	=	540	36,954,537	●

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.

$$\text{From } 470 \underline{\hspace{1cm}} 32,515,456 \bullet \div \text{From } 540 \underline{\hspace{1cm}} 36,954,537 \bullet \times \text{From } 503 \underline{\hspace{1cm}} 12,500,000 \bullet = 541 \underline{\hspace{1cm}} 10,998,465 \bullet$$

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.

$$\begin{array}{rcll} + & \text{From } [470] & \underline{\hspace{1cm}} & 32,515,456 \bullet \\ - & [542] & \underline{\hspace{1cm}} & 10,998,465 \bullet \\ = & [471] & \underline{\hspace{1cm}} & 21,516,991 \bullet \end{array} \times \text{ From } [30] \frac{[100.0000]}{\text{Ontario Allocation \%}} \times \text{ From } [516] \frac{0.2850}{\text{Capital Tax Rate \%}} \times \frac{[555]}{365} \frac{[365]}{(366 \text{ if leap year})} = + [523] \underline{\hspace{1cm}} 61,323 \bullet$$

**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 _____ X From % Ontario Allocation X From % Capital Tax Rate - - - - - = + _____

- Capital tax deduction from relating to **your corporation's** Capital Tax deduction, on Schedule 591 - - - - - From _____
= _____

$$\text{Capital Tax} \quad - \quad - \quad - \quad - \quad - \quad - \quad - \quad - \quad \boxed{562} \quad \underline{\hspace{1cm}} \quad \bullet \quad \times \quad \begin{array}{c} \text{Days in taxation year} \\ \boxed{555} \quad \boxed{365} \\ \hline \text{365} \quad \text{(366 if leap year)} \end{array} \quad - \quad - \quad - \quad - \quad - \quad = \quad \boxed{563} \quad \underline{\hspace{1cm}} \quad \bullet$$

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	61,323 ●
	Subtract: Specified Tax Credits applied to reduce capital tax payable (<i>Refer to Guide</i>)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	546	●
Capital Tax	543 – 546 (<i>amount cannot be negative</i>)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	=	550	61,323 ●

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

Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1

x

567

Capital Tax Rate (1)
(Refer to Guide)

%

x

From 30

100.0000

%

x

555

Days in taxation year
365
(366 if leap year)

- - - -

=

+

569

570

Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount

x

571

Capital Tax Rate (2)
(Refer to Guide)

%

x

From 30

100.0000

%

x

555

Days in taxation year
365
(366 if leap year)

- - - -

=

+

574

Capital Tax for Financial Institutions – other than Credit Unions (before Section 2)

569 + 574

- -

=

575

* If floating taxation year, refer to Guide.

2. Small Business Investment Tax Credit

(Retain details of eligible investment calculation and, if claiming an investment in CSBIF, retain the original letter approving the credit issued in accordance with the Community Small Business Investment Fund Act. Do not submit with this tax return.)

Allowable Credit for Eligible Investments

- - - - -

-

585

Financial Institutions: Claiming a tax credit for investment in Community Small Business Investment Fund (CSBIF)? (X) ☐ Yes

Capital Tax - Financial Institutions

575 - 585

- - - - -

=

586

Transfer to 543 on Page 12

Premium Tax (s.74.2 & 74.3) (Refer to Guide)

(1) Uninsured Benefits Arrangements

- - - - -

587

x

2 %

- -

=

588

Applies to Ontario-related uninsured benefits arrangements.

(2) Unlicensed Insurance (enter premium tax payable in 588 and attach a detailed schedule of calculations. If subject to tax under (1) above, add both taxes together and enter total tax in 588.)

Applies to Insurance Brokers and other persons placing insurance for persons resident or property situated in Ontario with unlicensed insurers.

Deduct: Specified Tax Credits applied to reduce premium tax (Refer to Guide)

- - - - -

-

589

Premium Tax

588 - 589

- - - - -

=

590

Transfer to page 17

DOLLARS ONLY

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

Net Income (loss) for federal income tax purposes, per federal T2 Schedule 1

- - - - - + 600 2,969,103 ●
Transfer to Page 15

Add:

Federal capital cost allowance	- - - - -	+	601	1,474,269 ●
Federal cumulative eligible capital deduction	- - - - -	+	602	84,735 ●
Ontario taxable capital gain	- - - - -	+	603	16,614 ●
Federal non-allowable reserves. Balance beginning of year	- - - - -	+	604	●
Federal allowable reserves. Balance end of year	- - - - -	+	605	●
Ontario non-allowable reserves. Balance end of year	- - - - -	+	606	●
Ontario allowable reserves. Balance beginning of year	- - - - -	+	607	●
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	- - - - -	+	608	●
Federal resource allowance (Refer to Guide)	- - - - -	+	609	●
Federal depletion allowance	- - - - -	+	610	●
Federal foreign exploration and development expenses	- - - - -	+	611	●
Crown charges, royalties, rentals, etc. deducted for Federal purposes (Refer to Guide)	- - - - -	+	617	●
Management fees, rents, royalties and similar payments to non-arm's length non-residents ▼				

Number of Days in Taxation Year

$$\text{[612]} \times 5 / 12.5 \times \left(\frac{\text{Days after Dec. 31, 2002 and before Jan. 1, 2004}}{\text{Total Days}} \right) = + \text{[633]} \quad \left(\frac{33}{365} \right)$$

$$\text{[612]} \times 5 / 14 \times \left(\frac{\text{Days after Dec. 31, 2003}}{\text{Total Days}} \right) = + \text{[634]} \quad \left(\frac{34}{365} \right)$$

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 - - - = 1,575,618 ● 640 1,575,618 ●
Transfer to Page 15

Deduct:

Ontario capital cost allowance (excludes amounts deducted under 675)	- - - - -	+	650	1,474,269 ●
Ontario cumulative eligible capital deduction	- - - - -	+	651	84,735 ●
Federal taxable capital gain	- - - - -	+	652	16,614 ●
Ontario non-allowable reserves. Balance beginning of year	- - - - -	+	653	●
Ontario allowable reserves. Balance end of year	- - - - -	+	654	●
Federal non-allowable reserves. Balance end of year	- - - - -	+	655	●
Federal allowable reserves. Balance beginning of year	- - - - -	+	656	●
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) (Retain calculations. Do not submit.)	- - - - -	+	657	●
Ontario depletion allowance	- - - - -	+	658	●
Ontario resource allowance (Refer to Guide)	- - - - -	+	659	●
Ontario current cost adjustment (Attach schedule)	- - - - -	+	661	●
CCA on assets used to generate electricity from natural gas, alternative or renewable resources.	- - - - -	+	675	●

Subtotal of deductions for this page 650 to 659 + 661 + 675 - - - - - 681 1,575,618 ●
Transfer to Page 15

continued on Page 15

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ
continued from Page 14

Net Income (loss) for federal income tax purposes, per federal Schedule 1	- - - - -	From	±	600	2,969,103	•
Total of Additions on page 14	- - - - -	From	=	640	1,575,618	•
Sub Total of deductions on page 14	- - - - -	From	=	681	1,575,618	•

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:

$$\left[\begin{array}{l} \text{From } 662 \cdot \times \\ \text{From } 30 \end{array} \right] \times \begin{array}{c} 100 \\ 100.0000 \end{array} - \text{From } 662 \cdot = 663 \cdot$$

Gross-up of CCA
Ontario Allocation

Workplace Child Care Tax Incentive (WCCT)

(Applies to eligible expenditures incurred prior to January 1, 2005.)

$$\begin{array}{l} \text{Qualifying expenditures:} \\ 665 \cdot \end{array} \times \begin{array}{c} 30 \% \\ \text{From } 30 \end{array} \times \begin{array}{c} 100 \\ 100.0000 \end{array} = 666 \cdot$$

Ontario allocation

Workplace Accessibility Tax Incentive (WATI)

(Applies to eligible expenditures incurred prior to January 1, 2005.)

$$\begin{array}{l} \text{Qualifying expenditures:} \\ 667 \cdot \end{array} \times \begin{array}{c} 100 \% \\ \text{From } 30 \end{array} \times \begin{array}{c} 100 \\ 100.0000 \end{array} = 668 \cdot$$

Ontario allocation

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)

$$\begin{array}{l} \text{Qualifying expenditures:} \\ 670 \cdot \end{array} \times \begin{array}{c} 30 \% \\ \text{From } 30 \end{array} \times \begin{array}{c} 100 \\ 100.0000 \end{array} = 671 \cdot$$

Ontario allocation

Educational Technology Tax Incentive (ETTI)

(Applies to eligible expenditures incurred prior to January 1, 2005.)

$$\begin{array}{l} \text{Qualifying expenditures:} \\ 672 \cdot \end{array} \times \begin{array}{c} 15 \% \\ \text{From } 30 \end{array} \times \begin{array}{c} 100 \\ 100.0000 \end{array} = 673 \cdot$$

Ontario allocation

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 = 1,575,618 • 680 1,575,618 •

Net income (loss) for Ontario Purposes 600 + 640 - 680 - - - - - = 690 2,969,103 •

Transfer to Page 4

DOLLARS ONLY

Continuity of Losses Carried Forward

	Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year	700 (2)	710 (2)	720 (2)	730	740	750
Add:						
Current year's losses (7)	701	711	721	731	741	751
Losses from predecessor corporations (3)	702	712	722	732		752
Subtotal	703	713	723	733	743	753
Subtract:						
Utilized during the year to reduce taxable income	704 (2)	715 (2) (4)	724 (2)	734 (2) (4)	744 (4)	754 (4)
Expired during the year	705		725	735	745	
Carried back to prior years to reduce taxable income (5)	706 (2) to Page 17	716 (2) to Page 17	726 (2) to Page 17	736 (2) to Page 17	746	
Subtotal	707	717	727	737	747	757
Balance at End of Year	709 (8)	719	729	739	749	759

Analysis of Balance at End of Year by Year of Origin

Year of Origin (oldest year first) year month day	Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800 9th preceding taxation year 1999-12-31	817 (9)	860 (9)		850	870
801 8th preceding taxation year 2000-12-31	818 (9)	861 (9)		851	871
802 7th preceding taxation year 2001-12-31	819 (9)	862 (9)		852	872
803 6th preceding taxation year 2002-05-06	820	830	840	853	873
804 5th preceding taxation year 2002-12-31	821	831	841	854	874
805 4th preceding taxation year 2003-12-31	822	832	842	855	875
806 3rd preceding taxation year 2004-12-31	823	833	843	856	876
807 2nd preceding taxation year 2005-12-31	824	834	844	857	877
808 1st preceding taxation year 2006-12-31	825	835	845	858	878
809 Current taxation year 2007-12-31	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:
 - the first day of the taxation year after the loss year,
 - the day on which the corporation's return for the loss year is delivered to the Minister, or
 - the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
- If a loss is being carried back to a predecessor corporation, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses			Non-Capital Losses	Total Capital Losses	Farm Losses	Restricted Farm Losses
Total amount of loss			910	920	930	940
Product: Loss to be carried back to preceding taxation years						
Applied to reduce taxable income						
Predecessor Ontario Corporation's Tax Account No. (MOF)	Taxation Year Ending year month day		911	921	931	941
3 rd preceding	2004-12-31	901	912	922	932	942
2 nd preceding	2005-12-31	902	913	923	933	943
1 st preceding	2006-12-31	903	From 706	From 716	From 726	From 736
Total loss to be carried back						
Balance of loss available for carry-forward			919	929	939	949

Summary	
Income Tax	- - - - - + From 230 or 320 414,053
Corporate Minimum Tax	- - - - - + From 280
Capital Tax	- - - - - + From 550 61,323
Premium Tax	- - - - - + From 590
Total Tax Payable	- - - - - = 950 475,376
Subtract: Payments	- - - - - - 960 480,975
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 -5,599
Payment due	- - - - - Enclosed * 990
Overpayment: Refund (Refer to Guide)	- - - - - = 975 5,599
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)
Lisa Milne

Title
Controller

Full Residence Address
24 Eastridge Road
RR 2
Walkerton
ON N0G 2V0

Signature
Lisa Milne

Date
June 24/08

Note: Section 76 of the Corporations Tax Act provides penalties for making false or misleading statements or omissions.

Attached Schedule with Total

Amounts deducted for income tax purposes in excess of amounts booked (Retain calculations. Do not submit.) (Int.B. 3012R)

Title NBV/UCC difference

Description	Amount	
NBV of capital assets	25,568,650	00
Less: Land	-227,769	00
UCC per SCH 008	-26,579,466	00
less: WIP	-61,179	00
NBV of Goodwill	2,214,322	00
CEC per SCH 010 x 4/3	-1,501,013	00
Regulatory assets difference b/w tax and accounting over the years	1,703,337	00
Unrealized loss	-446,464	00
Total	670,418	00

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Page 1 of 3

Corporation's Legal Name Westario Power Inc.	Ontario Corporations Tax Account No. (MOF) 1800342	Taxation Year End 2007-12-31

Part 1: Calculation of CMT Base

Banks – Net income/loss as per report accepted by Superintendent of Financial Institutions (SFI) under the Bank Act (Canada), adjusted so consolidation/equity methods are not used.

Life Insurance corporations – Net income/loss before Special Additional Tax as determined under s.57.1(2)(c) or (d)

Net Income/Loss (unconsolidated, determined in accordance with GAAP) ± [2100] 955,066 .

Subtract (to the extent reflected in net income/loss):

Provision for recovery of income taxes / benefit of current income taxes + [2101] .
Provision for deferred income taxes (credits) / benefit of future income taxes + [2102] 511,000 .
Equity income from corporations + [2103] .
Share of partnership(s)/joint venture(s) income + [2104] .
Dividends received/receivable deductible under fed.s.112 + [2105] .
Dividends received/receivable deductible under fed.s.113 + [2106] .
Dividends received/receivable deductible under fed.s.83(2) + [2107] .
Dividends received/receivable deductible under fed.s.138(6) + [2108] .
Federal Part VI.1 tax paid on dividends declared and paid, under fed.s.191.1(1) x 3 + [2109] .

Subtotal = 511,000 . ▶ - [2110] 511,000 .

Add (to extent reflected in net income/loss):

Provision for current taxes / cost of current income taxes + [2111] 1,052,000 .
Provision for deferred income taxes (debits) / cost of future income taxes + [2112] .
Equity losses from corporations + [2113] .
Share of partnership(s)/joint venture(s) losses + [2114] .
Dividends that have been deducted to arrive at net income per Financial Statements s.57.4(1.1) (excluding dividends under fed.s.137(4.1)) ... + [2115] .

Subtotal = 1,052,000 . ▶ + [2116] 1,052,000 .

Add/Subtract:

Amounts relating to s.57.9 election/regulations for disposals etc. of property for current/prior years

** Fed.s.85 + [2117] . or - [2118] .
** Fed.s.85.1 + [2119] . or - [2120] .
** Fed.s.97 + [2121] . or - [2122] .
** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years + [2123] . or - [2124] .
** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/prior years + [2125] . or - [2126] .
** Amounts relating to s.57.10 election/regulations for replacement re fed.s.13(4), 14(6) and 44 for current/prior years ... + [2127] . or - [2128] .

Interest allowable under ss.20(1)(c) or (d) of ITA to the extent not otherwise deducted in determining CMT adjusted net income - [2150] .

Capital gains on eligible donations of publicly-listed securities and ecologically sensitive land made after May 1, 2006 (to the extent reflected in net income/loss) - [2155] .

Subtotal (Additions) = ... ▶ + [2129] .

Subtotal (Subtractions) = ... ▶ - [2130] .

** Other adjustments ± [2131] .

Subtotal ± [2100] - [2110] + [2116] + [2129] - [2130] ± [2131] = [2132] 1,496,066 .

** Share of partnership(s)/joint venture(s) **adjusted** net income/loss ± [2133] .

Adjusted net income (loss) (if loss, transfer to [2202] in **Part 2: Continuity of CMT Losses Carried Forward.**) = [2134] 1,496,066 .

Deduct: * CMT losses: pre-1994 Loss + From [2210] .

* CMT losses: other eligible losses + [2211] .

= ▶ - [2135] .

* CMT losses applied cannot exceed adjusted net income or increase a loss

** Retain calculations. Do not submit with this schedule.

CMT Base = [2136] 1,496,066 .

Transfer to CMT Base on Page 8 of the CT23 or Page 6 of the CT8

CT23 Schedule 101

Corporation's Legal Name Westario Power Inc.	Ontario Corporations Tax Account No. (MOF) 1800342	Taxation Year End 2007-12-31

Part 2: Continuity of CMT Losses Carried Forward

Balance at Beginning of year NOTES (1), (2)		+	2201		
Add:					
Current year's losses		+	2202		
Losses from predecessor corporations on amalgamation NOTE (3)		+	2203		
Losses from predecessor corporations on wind-up NOTE (3)		+	2204		
Amalgamation (X) 2205 ☐ Yes Wind-up (X) 2206 ☐ Yes					
Subtotal		=			
Adjustments (attach schedule)		±	2208		
CMT losses available	2201 + 2207 ± 2208	=	2209		
Subtract:					
Pre-1994 loss utilized during the year to reduce adjusted net income		+	2210		
Other eligible losses utilized during the year to reduce adjusted net income NOTE (4)		+	2211		
Losses expired during the year		+	2212		
Subtotal		=			
Balances at End of Year NOTE (5)	2209 - 2213	=	2214		

Notes:

- (1) Pre-1994 CMT loss (see s.57.1(1)) should be included in the balance at beginning of the year. Attach schedule showing computation of pre-1994 CMT loss.
- (2) Where acquisition of control of the corporation has occurred, the utilization of CMT losses can be restricted. (see s.57.5(3) and a 57.5(7))
- (3) Include and indicate whether CMT losses are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.57.5(8) and s.57.5(9))
- (4) CMT losses must be used to the extent of the lesser of the adjusted net income 2134 and CMT losses available 2209.
- (5) Amount in 2214 must equal sum of 2270 + 2290.

Part 3: Analysis of CMT Losses Year End Balance by Year of Origin

For a pre-1994 loss, use the date of the last taxation year end before your corporation's first taxation year commencing after 1993.

	Year of Origin (oldest year first) year month day	CMT Losses of Corporation	CMT Losses of Predecessor Corporations
2240	9th preceding taxation year 1999-12-31	2260	2280
2241	8th preceding taxation year 2000-12-31	2261	2281
2242	7th preceding taxation year 2001-12-31	2262	2282
2243	6th preceding taxation year 2002-05-06	2263	2283
2244	5th preceding taxation year 2002-12-31	2264	2284
2245	4th preceding taxation year 2003-12-31	2265	2285
2246	3rd preceding taxation year 2004-12-31	2266	2286
2247	2nd preceding taxation year 2005-12-31	2267	2287
2248	1st preceding taxation year 2006-12-31	2268	2288
2249	Current taxation year 2007-12-31	2269	2289
Totals		2270	2290

The sum of amounts 2270 + 2290
must equal amount in 2214.

Corporate Minimum Tax (CMT) CT23 Schedule 101

Page 3 of 3

Corporation's Legal Name Westario Power Inc.	Ontario Corporations Tax Account No. (MOF) 1800342	Taxation Year End 2007-12-31

Part 4: Continuity of CMT Credit Carryovers

Balance at Beginning of year NOTE (1) + [2301] []

Add: Current year's CMT Credit ([280] on page 8 of the CT23
or [347] on page 6 of the CT8. If negative, enter NIL) + From [280] or [347] []

Gross Special Additional Tax NOTE (2) [312] on page 5 of CT8.
(Life Insurance corporations only.
Others enter NIL.) + From [312] []

Subtract Income Tax
([190] on page 6 of the CT23 or
page 4 of the CT8) - From [190] []

Subtotal (If negative, enter NIL) ... = [2305] []

Current year's CMT credit (If negative, enter NIL) [280] or [347] - [2305] ... = [2310] []

CMT Credit Carryovers from predecessor corporations NOTE (3) + [2325] []

Amalgamation (X) [2315] [] Yes Wind-up (X) [2320] [] Yes

Subtotal [2301] + [2310] + [2325] = [2330] []

Adjustments (*Attach schedule*) ± [2332] []

CMT Credit Carryover available [2330] ± [2332] = [2333] []

Transfer to Page 8 of the CT23 or Page 6 of the CT8

Subtract: CMT Credit utilized during the year to reduce income tax
([310] on page 8 of the CT23 or [351] on page 6 of the CT8.) + From [310] or [351] []

CMT Credit expired during the year + [2334] []

Subtotal = [2335] []

Balance at End of Year NOTE (4) [2333] - [2335] = [2336] []

Notes:

- (1) Where acquisition of control of the corporation has occurred, the utilization of CMT credits can be restricted. (see s.43.1(5))
- (2) The CMT credit of life insurance corporations can be restricted (see s.43.1(3)(b)).
- (3) Include and indicate whether CMT credits are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.43.1(4))
- (4) Amount in [2336] must equal sum of [2370] + [2390] .

Part 5: Analysis of CMT Credit Carryovers Year End Balance by Year of Origin

	Year of Origin (oldest year first) year month day	CMT Credit Carryovers of Corporation	CMT Credit Carryovers of Predecessor Corporation(s)
[2340]	9th preceding taxation year 1999-12-31	[2360]	[2380]
[2341]	8th preceding taxation year 2000-12-31	[2361]	[2381]
[2342]	7th preceding taxation year 2001-12-31	[2362]	[2382]
[2343]	6th preceding taxation year 2002-05-06	[2363]	[2383]
[2344]	5th preceding taxation year 2002-12-31	[2364]	[2384]
[2345]	4th preceding taxation year 2003-12-31	[2365]	[2385]
[2346]	3rd preceding taxation year 2004-12-31	[2366]	[2386]
[2347]	2nd preceding taxation year 2005-12-31	[2367]	[2387]
[2348]	1st preceding taxation year 2006-12-31	[2368]	[2388]
[2349]	Current taxation year 2007-12-31	[2369]	[2389]
Totals		[2370]	[2390]

The sum of amounts [2370] + [2390]
must equal amount in [2336] .

**Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule**

Corporation's Legal Name Westario Power Inc.	Ontario Corporations Tax Account No. (MOF) 1800342	Taxation Year End 2007-12-31

CMT Losses Carried Forward Workchart

(i) Continuity of Pre-1994 CMT Losses

	Corporation's Pre-1994 Loss	Predecessors' Pre-1994 Loss Amalgamation	Predecessors' Pre-1994 Loss Wind-Up
Date of the last tax year end before the corp's 1st tax year commencing after 1993			
Pre-1994 Loss (per schedule)			
Less: Claimed in prior taxation years commencing after 1993			
Pre-1994 Loss available for the current year			
Less: Deducted in the current year			
(max. = adj. net income for the year)			
Expired after 10 years			
Pre-1994 Loss Carryforward			

**(ii) Continuity of Other Eligible CMT Losses – Filing Corporation
(for losses occurring in tax years commencing after 1993)**

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1998-12-31					
9th Prior Year	1999-12-31					
8th Prior Year	2000-12-31					
7th Prior Year	2001-12-31					
6th Prior Year	2002-05-06					
5th Prior Year	2002-12-31					
4th Prior Year	2003-12-31					
3rd Prior Year	2004-12-31					
2nd Prior Year	2005-12-31					
1st Prior Year	2006-12-31					
Total						

Predecessor Corporations Only – Amalgamation

Indicate the amounts of eligible CMT losses from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1998-12-31						
1999-12-31						
2000-12-31						
2001-12-31						
2002-05-06						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Westario Power Inc.	1800342	2007-12-31

CMT Losses Carried Forward Workchart (continued)

Predecessor Corporations Only – Wind-Up

Indicate the amounts of eligible CMT losses from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1998-12-31						
1999-12-31						
2000-12-31						
2001-12-31						
2002-05-06						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Westario Power Inc.	1800342	2007-12-31

CMT Credit Carryovers Workchart

Filing Corporation

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1998-12-31					
9th Prior Year	1999-12-31					
8th Prior Year	2000-12-31					
7th Prior Year	2001-12-31					
6th Prior Year	2002-05-06					
5th Prior Year	2002-12-31					
4th Prior Year	2003-12-31					
3rd Prior Year	2004-12-31					
2nd Prior Year	2005-12-31					
1st Prior Year	2006-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

Indicate the amounts of CMT credit carryovers from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1998-12-31						
1999-12-31						
2000-12-31						
2001-12-31						
2002-05-06						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
	Total					

Predecessor Corporations Only – Wind-Up

Indicate the amounts of CMT credit carryovers from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1998-12-31						
1999-12-31						
2000-12-31						
2001-12-31						
2002-05-06						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
	Total					

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Westario Power Inc.	1800342	2007-12-31

Loans or Advances Credited or Advanced to Corporation

(includes accounts payable to related parties outstanding at the taxation year end for 120 days or more, and accounts payable to non-related parties outstanding for 365 days or more at the taxation year end)

Customer deposits	+	786,127
Long term liability	+	9,749
Current portion of Long Term Debt	+	320,358
Long-Term Debt	+	12,948,040
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
Total	=	14,064,274

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Westario Power Inc.	1800342	2007-12-31

- For use by a corporation to claim any of the following:
 - Charitable donations;
 - Gifts to Her Majesty in right of Ontario, to Ontario crown agencies, or to Ontario Crown foundations;
 - Gifts to Canada or a province;
 - Gifts of certified cultural property; or
 - Gifts of certified ecologically sensitive land.
- The donations and gifts are eligible for a five year carry-forward.
- Use this schedule to show a credit transfer following an amalgamation or wind-up of subsidiary as described under subsection 87(1) and 88(1) of the federal *Income Tax Act* (Canada).
- For donations and gifts made after March 22, 2004, subsection 34(1.1) of the *Corporations Tax Act* parallels subsection 110.1(1.2) of the *Income Tax Act* and provides as follows:
 - where a particular corporation has undergone a change of control, for taxation years that end on or after the change of control, no corporation can claim a deduction for a gift made by a particular corporation to a qualified donee before the change of control;
 - if a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the change of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- File one completed copy of this schedule with your CT23.

Part 1 – Charitable Donations

Charitable Donations at end of preceding taxation year		+		A
Deduct: Donations expired after 5 taxation years		–		B
Charitable donations at beginning of taxation year		=		C
Add: Donations transferred on amalgamation or wind-up of subsidiary		+		D
Total current year charitable donations made		+	11,580	E
Subtotal D + E		=	11,580	
		▶	11,580	F
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)		–		G
Total donations available C + F – G		=	11,580	H
Deduct: Amount applied against taxable income (amount U , Part 2)		–	11,580	U
Charitable donations closing balance		=		I

Part 2 – Maximum Deduction Calculation for Donations

Ontario net income for tax purposes multiplied by 75%		=	2,226,827	J
Note: For credit unions the Ontario net income for tax purposes is the amount before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.				
Ontario taxable capital gains arising in respect of gifts of capital property		+		K
Ontario taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01) ITA		+		L
Add the lesser of:				
1. The amount of the recapture of capital cost allowance in respect of charitable gifts				M
2. The lesser of:				
2a. Proceeds of dispositions less outlays and expenses				N
2b. The capital cost				O
The lesser of N and O		▶		P
The lesser of M and P		▶		Q
Subtotal K + L + Q		=		R
25% X				S
Maximum deduction allowable J + S		=	2,226,827	T
Claim for charitable donations (not exceeding the lesser of H from Part 1, T and net income for tax purposes)			11,580	U

 Enter in 1 of the CT23

Corporation's Legal Name Westario Power Inc.	Ontario Corporations Tax Account No. (MOF) 1800342	Taxation Year End 2007-12-31

Part 3 – Gifts to Her Majesty in right of Ontario

For use by a corporation claiming gifts to Her Majesty in right of Ontario, to Ontario Crown Agencies, or to Ontario Crown Foundations.

Gifts to Ontario Crown Agency or Ontario Crown Foundation at end of the preceding taxation year	 +	
Deduct: Gifts expired after 5 years	 -	
Gifts to Ontario Crown Agency or Ontario Crown Foundation at the beginning of the taxation year	 =	
Add: Gifts transferred on amalgamation or wind-up of a subsidiary	 +	
Total current year gifts	 +	
Subtotal	 =	
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	 -	
Total gifts available	 =	
Deduct: Amount applied against taxable income 2 of the CT23	 -	
Gifts to Ontario Crown Agency or Ontario Crown Foundation closing balance	 =	

Foundation Name	Date of Donation	Amount \$

Total gifts to Her Majesty in right of Ontario =

Part 4 – Maximum Deduction Calculation for Gifts to Her Majesty in Right of Ontario

Deduction is the lesser of:

1. Ontario Net Income before deductions of gifts after deducting charitable donations and gifts to Her Majesty in right of Canada or a province other than Ontario		2,957,523 ^V
2. Lesser of:		
2a. Ontario Net Income for the taxation year	 2,969,103 ^W	
2b. Gifts made in the taxation year or any of the five preceding taxation years to Her Majesty in Right of Ontario, an Ontario Crown Agency or an Ontario Crown Foundation	 X	
The lesser of W and X		Y
Maximum deduction allowable the lesser of V and Y		Z

Transfer to of the CT23

Part 5 – Gifts to Canada or a province other than Ontario

Gifts to Canada or a province other than Ontario at the end of the preceding year	 +	
Deduct: Gifts to Canada or a province other than Ontario expired after five taxation years	 -	
Gifts to Canada or a province other than Ontario at the beginning of the taxation year	 =	
Add: Gifts to Canada or a province other than Ontario transferred on amalgamation or wind-up of a subsidiary	 +	
Total current year Gifts to Canada or a province other than Ontario (Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date.)	 +	
Subtotal	 =	
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	 -	
Total gifts to Canada or a province other than Ontario available	 =	
Deduct: Amount applied against taxable income	 -	
Gifts to Canada or a province other than Ontario closing balance	 =	

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Westario Power Inc.	1800342	2007-12-31

Part 6 – Gifts of certified cultural property

Gifts of certified cultural property at the end of the preceding taxation year		+	
Deduct: Gifts of certified cultural property expired after five years		-	
Gifts of certified cultural property at the beginning of the taxation year		=	
Add: Gifts of certified cultural property transferred on amalgamation or wind-up of a subsidiary		+	
Total current year gifts of certified cultural property		+	
Subtotal		=	
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)		-	
Total gifts of certified cultural property available		=	
Deduct: Amount applied against taxable income		-	
Gifts of certified cultural property closing balance		=	

Part 7 – Gifts of certified ecologically sensitive land

Gifts of certified ecologically sensitive land at the end of the preceding taxation year		+	
Deduct: Gifts of certified ecologically sensitive land expired after five years		-	
Gifts of certified ecologically sensitive land at the beginning of the taxation year		=	
Add: Gifts of certified ecologically sensitive land transferred on amalgamation or wind-up of a subsidiary		+	
Total current year gifts of certified ecologically sensitive land		+	
Subtotal		=	
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)		-	
Total gifts of certified ecologically sensitive land available		=	
Deduct: Amount applied against taxable income		-	
Gifts of certified ecologically sensitive land closing balance		=	

Part 8 – Analysis of balance by year of origin

Year of origin	Charitable donations	Gifts to Her Majesty in right of Ontario	Gifts to Canada or a province other than Ontario	Gifts of certified cultural property	Gifts of certified ecologically sensitive land
2006-12-31					
2005-12-31					
2004-12-31					
2003-12-31					
2002-12-31					
2002-05-06					
Totals					

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
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- For a corporation that has disposed of capital property or claimed an allowable business investment loss, or both, in the taxation year.
- This schedule may be used to make a designation under section 34(10) of the *Corporations Tax Act* provided the corporation has made a designation under paragraph 111(4) (e) of the *Income Tax Act* (Canada), if control of the corporation has been acquired by a person or group of persons.

Part A: Designation under section 34(10) of the *Corporations Tax Act*

Complete part A if there are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e) of the *Income Tax Act* (Canada) or section 34(10) of the *Corporations Tax Act*.

Property	Class #	Date of disposition YYYY/MM/DD	Proceeds of disposition	Adjusted cost base	Other adjustments	Designated amount	Gain or loss

Part B: Inter-provincial asset transfers

Complete part B if there was any disposition shown on the schedule as a result of a federal election under section 85 of the *Income Tax Act* (Canada) that transferred assets to a non-arm's length corporation with a permanent establishment in another Canadian jurisdiction.

Property	Class #	Corporation name of transferee/or	Date of disposition YYYY/MM/DD	Cost of asset in other jurisd.	Name of other jurisdiction	Allocation ratio to other jurisdictions	Ontario elected amount	Gain or loss
						%		
						%		
						%		
						%		

Part 1 – Shares

1 Types of capital property			2 Date of acquisition YYYY/MM/DD	3 Date of disposition YYYY/MM/DD	4 Proceeds of disposition	5 Ontario adjusted cost base	6 Outlays and expenses	7 Ontario gain or (loss) (col. 4 less cols. 5 & 6)
No. of shares	Name of corporation	Class of shares						
1								
Totals								A

Corporation's Legal Name Westario Power Inc.	Ontario Corporations Tax Account No. (MOF) 1800342	Taxation Year End 2007-12-31

1 Types of capital property	2 Date of acquisition YYYY/MM/DD	3 Date of disposition YYYY/MM/DD	4 Proceeds of disposition	5 Ontario adjusted cost base	6 Outlays and expenses	7 Ontario gain or (loss) (col. 4 less cols. 5 & 6)

Part 2 – Real Estate (Do not include losses on depreciable property)

	Municipal address	2	3	4	5	6	7
1	Land			48,227	15,000		33,227
2							
Totals							33,227 B

Part 3 – Bonds

	Face value	Maturity date YYYY/MM/DD	Name of issuer	2	3	4	5	6	7
1									
Totals									C

Part 4 – Other properties (Do not include losses on depreciable property)

	Description	2	3	4	5	6	7
1							
Totals							D

Part 5 – Personal-use property

	Description of capital property	2	3	4	5	6	7
1							

*Note: Losses are not deductible*Net gain or (loss) **E****Part 6 – Listed personal property**

	Description	2	3	4	5	6	7
1							

Deduct: Unapplied listed personal property losses from other years Net gain or (loss) **F***Note: Net listed personal property losses may only be applied against personal property gains.*

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Westario Power Inc.	1800342	2007-12-31

Part 7 – Property qualifying for and resulting in an allowable business investment loss

1 Name of small business corporation		Shares – enter 1 Debt – enter 2	2 Date of acquisition YYYY/MM/DD	3 Date of disposition YYYY/MM/DD	4 Proceeds of disposition	5 Ontario adjusted cost base	6 Outlays and expenses	7 Ontario loss (col. 4 less cols. 5 & 6)
1								
Note: Properties listed in Part 7 should not be included in any other Part of Schedule 6.				Totals				
							Net Loss	G

Allowable business investment loss **G** x 50 % = **G1**
 Transfer to **678** of the CT23 or CT8

Determining capital gains and capital losses

Total of A to F (Do not include F if it is a loss)	33,227
Add: Amount (if any) of capital gain reserve opening balance from Schedule 13	+
Capital gain dividend received in the year	+
Subtotal	= 33,227
Deduct: Amount (if any) of capital gain reserve closing balance from Schedule 13	-
Gain or Loss (excluding Allowable Business Investment Losses)	= 33,227 H

Determining taxable capital gains

Gain or Loss (excluding Allowable Business Investment Losses)	33,227 H
Deduct:	
Gain on donations (made to charities other than private foundations) of securities listed on a prescribed stock exchange	
realized prior to May 2, 2006	x 50 % -
realized after May 1, 2006	-
Gain on donation of ecologically sensitive land	
realized prior to May 2, 2006	x 50 % -
realized after May 1, 2006	-
Gains or Loss	33,227 I
Include 100% of the losses in box 711 of the CT23 or CT8	
Taxable capital gains	33,227 I x 50 % = 16,614 J
Transfer to 603 of the CT23 or CT8	

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Westario Power Inc.	1800342	2007-12-31

 Is the corporation electing under regulation 1101(5q)? 1 ☐ Yes 2 ☒ No

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (column 8 multiplied by column 9; or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (column 6 minus column 12)
1	11,973,360			0	11,973,360		11,973,360	4	0	0	478,934	11,494,426
1		2,443,787		0	2,443,787	1,221,894	1,221,893	6	0	0	73,314	2,370,473
2	6,287,132			0	6,287,132		6,287,132	6	0	0	377,228	5,909,904
8	422,494			0	422,494		422,494	20	0	0	84,499	337,995
47	4,580,392	2,346,570		0	6,926,962	1,173,285	5,753,677	8	0	0	460,294	6,466,668
Totals	23,263,378	4,790,357			28,053,735	2,395,179	25,658,556				1,474,269	26,579,466

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule. See Regulation 1100(2) and (2.2) of the *Income Tax Act* (Canada).

 Enter in boxes on the CT23.

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.



Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Ontario Cumulative Eligible Capital Deduction Schedule 10 Page 1 of 2

For taxation years 2002 and later

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Westario Power Inc.	1800342	2007-12-31

- For use by a corporation that has eligible capital property.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Ontario Cumulative eligible capital – balance at end of preceding taxation year (if negative, enter zero) = + 1,210,495 **A**

Add: Cost of eligible capital property acquired during the taxation year + ... **B**
Other adjustments + ... **C**
B + C = ... x 3 / 4 = ... **D**

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 x 1 / 2 = - **E**

D minus E (if negative, enter zero) = ... **F**

Amount transferred on amalgamation or wind-up of subsidiary + ... **G**

Subtotal A + F + G = 1,210,495 **H**

Deduct: Ontario proceeds of sales (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year + ... **I**

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) of the *Income Tax Act* (Canada) + ... **J**

Other adjustments + ... **K**

I + J + K = ... x 3 / 4 = - **L**

Ontario cumulative eligible capital balance H minus L = 1,210,495 **M**

If **M** is negative, enter zero at line **Q** and proceed to **Part 2**, page 2.

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business **N**

From **M** 1,210,495

From **N** -

Current year deduction M minus N = 1,210,495 x 7 % = + 84,735 **O**

N + O = 84,735 **P**

Note: The maximum current year deduction is 7%. Any amount up to the maximum deduction of 7% may be claimed.
For taxation years starting after December 21, 2000, the deduction may not exceed the maximum amount prorated for the number of days in the taxation year divided by 365 or 366 days.
Enter amount in box 651 of the CT23

Ontario cumulative eligible capital - closing balance M minus P (if negative, enter zero) = 1,125,760 **Q**

See page 2 - Part 2

Ontario Cumulative Eligible Capital Deduction
Schedule 10 Page 2 of 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Westario Power Inc.	1800342	2007-12-31

Part 2 – Amount to be included in income arising from disposition

Complete this part only if the amount at line M is negative.

Amount from line M above. *Show this as a positive amount; not negative.* **R**

Total cumulative eligible capital deductions from income for taxation
years beginning after June 30, 1988 + ... **1**

Total of all amounts which reduced cumulative eligible capital in the
current or prior years under subsection 80(7) of the ITA + ... **2**

Total of cumulative eligible capital deductions claimed
for taxation years beginning before July 1, 1988 + ... **3**

Negative balances in the cumulative eligible capital
account that were included in income for taxation
years beginning before July 1, 1988 - **4**

Deduct line 4 from line 3 (if negative, enter zero) = ... **5**

Total lines 1 + 2 + 5 = ... **6**

Amounts included in income under paragraph 14(1)(b), as that
paragraph applied to taxation years ending after June 30, 1988
and before February 28, 2000, to the extent that it is for an
amount described at line 1 **7**

Amounts at **Line Z** from Ontario Schedule 10 of previous taxation
years ending after February 27, 2000
(This will be **Line T** in earlier versions of this schedule.) + ... **8**

Total lines 7 + 8 = ... **9**

Deduct line 9 from line 6 (if negative, enter zero) = ... **S**

R minus S (if negative, enter zero) = ... **T**

From **Line 5** x 1 / 2 = - **U**

T minus U (if negative, enter zero) = ... **V**

From **V** x 2 / 3 = ... **W**

Lesser of **R** and **S** = + ... **Z**

Amount to be included in income W + Z = ...

Corporate Taxpayer Summary

Corporate information

Corporation's name	Westario Power Inc.														
Taxation Year	2007-01-01		to	2007-12-31											
Jurisdiction	Ontario														
BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
☐	☐	☐	☐	☒	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Corporation is associated	Y														
Corporation is related	Y														
Number of associated corporations	2														
Type of corporation	Canadian-Controlled Private Corporation														
Total amount due (refund) federal and provincial*	-5,599														

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensitive help.

Summary of federal information

Net income	2,969,103	
Taxable income	2,957,523	
Donations	11,580	
Calculation of income from an active business carried on in Canada	2,952,489	
Dividends paid	461,053	
Balance of the low rate income pool at the end of the previous year		
Balance of the low rate income pool at the end of the year		
Balance of the general rate income pool at the end of the previous year	3,122,391	
Balance of the general rate income pool at the end of the year	5,122,209	
Part I tax (base amount)	1,123,859	
Surtax	33,124	
Credits against part I tax	Summary of tax	Refunds/credits
Small business deduction	Part I 656,475	ITC refund
M&P deduction	Part I.3	Dividends refund 4,430
Foreign tax credit	Part IV	Instalments 652,045
Political contributions	Part III.1	Surtax credit
Investment tax credits	Other*	Other*
Abatement/Other* 501,616	Provincial or territorial tax	
		Balance due/refund (-)

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryback amounts	
Investment tax credits	
Non-capital loss	
Capital loss	
Farm loss	
Restricted farm loss	
Surtax credit	
Part I tax credit (Schedule 42)	
Federal foreign non-business income tax credit	
Carryforward balances	
RDTOH	
Charitable donations	
Gifts to Canada, a province or a territory	

Summary of federal carryforward/carryback information (continued)

Gifts of certified cultural property	
Gifts of certified ecologically sensitive land	
Gifts of medicine	
Investment tax credits	
Non-capital losses	
Capital/L.P.P. losses	
Farm losses	
Restricted farm losses	
Current year's balance of SR&ED expenditures (T661)	
Foreign business tax credit	
Unused surtax credit (Schedule 37)	14,454
Capital dividend amount	16,614
Part I tax credit (Schedule 42)	
Cumulative eligible capital	1,125,760
Capital gains reserves	
Financial statement reserve	
Other reserves	
Balance of patronage dividends	
Continuity of exemption of accumulated income	

Summary of provincial information – provincial income tax payable

	Ontario (CT-23)	Québec (CO-17)	Alberta (AT1)
Net income	2,969,103		
Taxable income	2,957,523		
% Allocation	100.00		
Attributed taxable income	2,957,523		
Surtax	34,000	N/A	N/A
Tax payable before deduction*	414,053		
Deductions and credits	34,000		
Net tax payable	414,053		
Attributed taxable capital	32,515,456		N/A
Capital tax payable**	61,323		N/A
Total tax payable***	475,376		
Instalments and refundable credits	480,975		
Balance due/Refund (-)	-5,599		

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes corporate minimum tax and premium tax.

	British Columbia	Saskatchewan	Manitoba
% Allocation			
Attributed taxable income			
Tax payable before deduction			
Deductions and credits			
Tax payable or refundable credit			
Attributed taxable capital			
Capital tax payable			
Instalments and refundable credits			
Balance due/Refund (-)			

Summary of provincial information – provincial income tax payable (continued)

	Newfoundland and Labrador	Prince Edward Island	Nova Scotia	New Brunswick
% Allocation				
Attributed taxable income				
Tax payable before deduction				
Deductions and credits				
Tax payable or refundable credit				
Attributed taxable capital				
Capital tax payable				
Instalments and refundable credits				
Balance due/Refund (-)*				
* Only applies in the case of bank, a loan corporation or a trust corporation.				
		Yukon	Northwest Territories	Nunavut
% Allocation				
Attributed taxable income				
Tax payable before deduction				
Deductions and credits				
Tax payable or refundable credit				

Summary of provincial carryforward amounts

	Ontario	Québec	Alberta
Non-capital losses			
Net capital/L.P.P. losses			
Farm losses			
Restricted farm losses			
Donations			
Capital gains reserves			
Financial statement reserves			
Other reserves			
Eligible capital	1,125,760	1,125,760	1,125,760
Other carryforward amounts			
Ontario			
Continuity of other eligible CMT losses – Filling Corporation – OCMT101			
Predecessor corporations only – Amalgamation – OCMT101			
Predecessor corporations only – Wind-up – OCMT101			
CMT credit carryovers workchart – Filling Corporation – OCMT101			
CMT credit carryovers workchart – Predecessor corporations only – Amalgamation			
CMT credit carryovers workchart – Wind-up – OCMT101			
Ontario current taxation year closing balance in pool of deductible SR&ED expenditures – O161			
Continuity Schedule for Federal ITC relating to SR&ED Expenditures for the Preceding Taxation Year – O161			
Continuity Schedule for the Amount of Federal ITC from SR&ED Expenditures relating to QORD for the Preceding Taxation Year – O161			
Québec			
R&D expenditures not deducted at the end of the year – RD-222			
Foreign non-business income tax credits – CO-17S.39			
Development work expenses – FM220.3			
Excess development work expenses – FM220.3			
Balance of patronage dividends – CO-786			
Alberta			
Unclaimed SR&ED expenditure pool deduction balance – A16			
British Columbia			
Scientific research and experimental development – Schedule 425			
Manufacturing and processing – Schedule 426			
Manitoba			
Research and development – Schedule 380			
Manufacturing investment – Schedule 381			
Co-operative education – Schedule 384			
Odour control – Schedule 385			
Saskatchewan			
Manufacturing and processing investment – Schedule 402			
Research and development – Schedule 403			
Newfoundland and Labrador			
Direct equity tax – Schedule 303			
Prince Edward Island			
Investment – Schedule 321			
Nova Scotia			
Energy efficiency tax credit – Schedule 342			
Manufacturing and processing investment – Schedule 344			
New Brunswick			
Research and development – Schedule 360			
Nunavut			
Investment – Schedule 480			

Five Year Comparative Summary

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Federal information (T2)					
Taxation year end	2007-12-31	2006-12-31	2005-12-31	2004-12-31	2003-12-31
Net income	2,969,103	3,419,918	1,954,071	887,147	799,835
Taxable income	2,957,523	3,416,945	1,945,995	86,887	
Active business income	2,952,489	3,419,918	1,954,071	887,147	799,835
Dividends paid	461,053	319,017	427,109		
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year	3,122,391				
GRIP – end of the year	5,122,209	3,122,391			
Donations	11,580	2,973	8,076		
Balance due/refund (-)		755,828	430,453	19,219	

Federal taxes					
Part I before surtax	623,351	1,298,439	408,658	18,246	
Surtax	33,124	38,270	21,795	973	
Part I.3					46,740
Part IV					
Part I & Surtax	656,475	755,828	430,453		
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensitive help.

Credits against part I tax					
Small business deduction					
M&P deduction					
Foreign tax credit					
Political contribution					
Investment tax credit					
Abatement/other*	501,616	580,881	330,820	8,689	

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensitive help.

Refunds/credits					
ITC refund					
Dividend refund	4,430				
Instalments	652,045				46,740
Surtax credit					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensitive help.

Ontario (CT-23)

<u>Taxation year end</u>	<u>2007-12-31</u>	<u>2006-12-31</u>	<u>2005-12-31</u>	<u>2004-12-31</u>	<u>2003-12-31</u>
Net income	2,969,103				
Taxable income	2,957,523				
% Allocation	100.00				
Attributed taxable income	2,957,523	3,416,945	1,945,995	86,595	
Surtax	34,000	34,000			
Income tax payable before deduction	414,053	478,372	272,439	12,123	
Income tax deductions /credits	34,000	34,000	159,989		
Net income tax payable	414,053	478,372	112,450	12,123	
Taxable capital	32,515,456	30,153,736	28,624,931	28,635,797	25,673,676
Capital tax payable	61,323	64,387	66,702	73,110	64,242
Total tax payable*	475,376	542,759	179,152	120,512	107,877
Instalments and refundable credits	480,975	508,001	128,343		
Balance due/refund	-5,599	34,758	50,809	-34,092	31,213

* This includes corporate minimum tax and premium tax.

Description of Deferral and Variance Accounts

Commodity Accounts are classified as follows:

1588 Retail Settlement Variance Account – Power

Description: To record the net difference between the energy amount billed to customers and the energy charge to a distributor by the IESO, Host distributor, or embedded generator.

1588 RSVA Power, Sub-account Global Adjustments

Description: To record the net difference between the global adjustment amount billed to customers and the global adjustment amount charge to distributors by the IESO, Host distributor, or embedded generator.

Non-Commodity Accounts are classified in two Categories as follows:

Wholesale and Retail Market Variance Accounts

1518 Retail Cost Variance Account – Retail

Description: To record the net of revenues from services such as, establishing service agreements, distributor consolidated billing, Retailer consolidated billing, and split billing, and the costs of entering into service agreements with retailers.

1548 Retail Cost Variance Account – STR

Description: To record the net of revenues derived from Service Transaction Request ('STR') services and the incremental costs of providing the services associated with STR's

1580 Retail Settlement Variance Account - Wholesale Market Service Charges

Description: This account is used to record the net difference between the amount charged by the IESO and the amount billed to customers.

1582 Retail Settlement Variance Account - One-time Wholesale Market Service

Description: One-time Wholesale Market Service was billed by (H.O.N.I.) from January 1st, 2005 to May 1st, 2006 was charged to Embedded Utilities.

1584 Retail Settlement Variance Account - Retail Transmission Network Charges

Description: To record the net of charges for Transmission Network Services and the amount billed to customers for the same services.

1586 Retail Settlement Variance Account - Retail Transmission Connection Charges

Description: To record the net of charges for Transmission Connection Services and the amount billed to customers for the same services.

1588 Retail Settlement Variance Account - Power

Description: Refer to commodity accounts description

1588 Retail Settlement Variance Account - Power Sub-Account Global

Description: Refer to commodity accounts description.

Utility Deferral Accounts

1508 Other Regulatory Assets - Sub-account OEB Cost Assessments

Description: To capture the variance between OEB Cost Assessments amount approved in 1999 versus the actual OEB Cost Assessments charged.

1508 Other Regulatory Assets - Sub-account Pension Contributions

Description: To record the pension costs associated with the cash contributions paid to Ontario Municipal Employees Retirement Savings ("OMERS") for the period from January 1, 2005 to April 30, 2006.

1525 Miscellaneous Deferred Debits

Description: To record debits not elsewhere provide for which will benefit future periods.

1550 LV Variance

Description: To record the net of the amount charged by a host distributor to an embedded distributor for transmission low voltage services and the amount billed to the embedded distributor's customers.

1555 Smart Meter Capital and Recovery Offset Variance

Description: To capture the amount billed to WPI's customers

1565 Smart Meter OM&A Variance

Description: To capture the amount spent by WPI with respect to Smart Meter Operation and Maintenance

1562 Deferred Payments in Lieu of Taxes

Description: To record the amount resulting from the Board approved PILs methodology for determining the 2001 Deferral Account Allowance and the PILs proxy amount determined for 2002 and subsequent years.

1563 PILs contra account

Description: This account is a contra to account 1562.

1565 Conservation and Demand Management Expenditures and Recoveries

Description: To capture amounts relating to the costs incurred for conservation and demand management activities and expenditures, and the revenue proxy amount equivalent to the distributor's (first generation) third tranche of MARR (market adjusted revenue requirement) or an amount otherwise approved by the Board.

1566 CDM Contra

Description: To record the offsetting entry for amounts recorded in account 1565, Conservation and Demand Management (CDM) Expenditures and Recoveries, for the reversal of entries to the accounts of original entries.

1572 Extraordinary Event Losses

Description: to record extraordinary event costs that meet the qualifying criteria established in the 2000 Electricity Distribution Rate Handbook.

1574 Deferred Rate Impact Amounts

Description: To record amounts equal to rate impacts associated with market-based rate of return, transition costs, and extraordinary costs that the utility has determined to be excessive and has decided to defer to future periods.

1592 PILS & Tax Variance

Description: To capture the Variance between the PILS & tax billed to WPI's customers and the amount of PILS payable.

2425 Other Deferred Credits

Closed Accounts not classified are as follows:

1570 Qualifying Transition Costs (closed December 31, 2002)

Description: To capture all expenses for Transition Costs.

1571 Pre-Market Opening Energy Variances (closed April 30, 2002)

Description: To capture the difference between the T.O.U and Non T.O.U short fall. Charges were approved by OEB.

Notes:

WPI follows and is in compliance with the OEB's Uniform System of Accounts for electricity distributors.

The RSVA power account 1588 is designed to capture variances due to billing timing differences (i.e. electricity charged by IESO to LDCs vs. electricity billed by LDCs to their customers), price and quantity differences (i.e. arising from final vs. preliminary IESO settlement invoices), and line loss differences (i.e. actual vs. estimated line loss factors).

This account is not designed to capture any price differences between the regulated price plan (RPP) and spot prices applicable to RPP customers. This is the function of the Ontario Power Authority (OPA) RPP variance account which is trued-up in accordance with the terms established by the Board for the RPP.

Accordingly, since the RSVA power account is generic to all customers of an LDC, disposition of the account balance in rates is attributable to all its customers.

The 1588 RSVA power - Sub-account Global Adjustments is designed for the global adjustments applicable to non-RPP customers. Hence, the disposition of the account balance should be attributable to non-RPP customers.

Calculation of Balances by Account

WPI calculates all balances in the Deferral and Variance accounts in accordance with the Electricity Distribution Rate Handbook and Article 490 of the Accounting Procedures Handbook for Electric Distribution Utilities.

Carrying charges on Deferral and Variance accounts are calculated using the billed method. This methodology is consistent with the Applicant's Regulatory Assets Review – Phase II RP-2005-0020/EB2005-0434.

There are differences between RRR Filings submitted for the years ended December 31, 2006 and December 31, 2007. The differences are noted as follows:

Account 1508

	Balance reported December 31, 2006	Balance reported December 31, 2007
	\$226,993.00	\$230,196.00
Revised	\$238,653.00	\$253,509.00

The above adjustments include accumulated carrying charges that had not previously been accrued (accumulated amounts are \$11,660 in 2006 and \$23,313 in 2007). The above amounts have been properly reflected in the calculation of the deferral and variance balances as per Attachment to Exhibit 5, Tab 1, Schedule 2, and in the calculation of the proposed rate rider recovery as per Attachment to Exhibit 5, Tab 1, Schedule 3.

Account 1518

	Balance reported December 31, 2006	Balance reported December 31, 2007
	(\$23,104.00)	(\$45,207.00)
Revised	(\$23,600.00)	(\$47,324.00)

The above adjustments include accumulated carrying charges that had not previously been accrued (accumulated amounts are (\$496) in 2006 and (\$2,117) in 2007). The above amounts have been properly reflected in the calculation of the deferral and variance balances as per Attachment to Exhibit 5, Tab 1, Schedule 2, and in the calculation of the proposed rate rider recovery as per Attachment to Exhibit 5, Tab 1, Schedule 3.

Account 1548

	Balance reported December 31, 2006	Balance reported December 31, 2007
	\$52,092.00	\$77,234.00
Revised	\$54,105.00	\$82,229.00

The above adjustments include accumulated carrying charges that had not previously been accrued (accumulated amounts are \$2,013 in 2006 and \$4,995 in 2007). The above amounts have been properly reflected in the calculation of the deferral and variance balances as per Attachment to Exhibit 5, Tab 1, Schedule 2, and in the calculation of the proposed rate rider recovery as per Attachment to Exhibit 5, Tab 1, Schedule 3.

Account 1525

	Balance reported December 31, 2006	Balance reported December 31, 2007
	(\$33,940.00)	(\$33,940.00)
Revised	\$0.00	\$0.00

The above adjustment is a result of the decision from the 2006 Regulatory Assets Review – Phase II RP-2005-0020/EB2005-0434. The amount above had not been properly allocated to account 4380. The above amount has been properly reflected in the calculation of the deferral and variance balances as per Attachment to Exhibit 5, Tab 1, Schedule 2, and in the calculation of the proposed rate rider recovery as per Attachment to Exhibit 5, Tab 1, Schedule 3.

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B5 Deferral / Variance Account Balances

Interest Rate (from sheet Y1) = 3.35%

Deferral / Variance Account	1-Jan-2005 to 31-Dec-2005					
	Open. Principal	Changes	End. Principal	Open. Interest	Changes	End. Interest
1505-Unrecovered Plant and Regulatory Study Costs						
1508-Other Regulatory Assets	19,326	165,755	185,081	8,669	(3,939)	4,730
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail	51,323	(6,334)	44,989	8,493	3,497	11,990
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits	42,299	(26,397)	15,902			
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-RCVASTR	34,975	25,183	60,158	2,521	3,187	5,708
1550-LV Variance Account						
1555-Smart Meters Capital Variance Account						
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes	555,267	(484,121)	71,146	17,427	69,519	86,947
1563-Account 1563 - Deferred PILs Contra Account	(499,457)	484,121	(15,336)	(17,427)	(69,519)	(86,946)
1565-Conservation and Demand Management Expenditures and Recoveries		(433,672)	(433,672)			
1566-CDM Contra Account		433,672	433,672			
1570-Qualifying Transition Costs	1,971,022		1,971,022	362,063	142,899	504,962
1571-Pre-market Opening Energy Variance	1,021,006		1,021,006			
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	521,946	363,071	885,016	150,157	70,622	220,779
1582-RSVAONE-TIME	89,441	23,629	113,070	7,785	7,148	14,933
1584-RSVANW	12,823	(50,566)	(37,744)	72,192	18,868	91,060
1586-RSVACN	(380,687)	(529,162)	(909,850)	19,197	(22,220)	(3,023)
1588-RSVAPOWER	935,477	1,553,888	2,489,366	682,074	325,862	1,007,936
1592-2006 PILs/Taxes Variance						
2425-Other Deferred Credits						
TOTAL	4,374,761	1,519,066	5,893,827	1,313,151	545,925	1,859,076

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B5 Deferral / Variance Account Balances

Interest Rate (from sheet Y1) = 3.35%

Deferral / Variance Account	1-Jan-2006 to 31-Dec-2006					
	Open. Principal	Changes	End. Principal	Open. Interest	Changes	End. Interest
1505-Unrecovered Plant and Regulatory Study Costs						
1508-Other Regulatory Assets	185,081	45,347	230,428	4,730	3,496	8,225
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail	44,989	(68,093)	(23,104)	11,990	(12,486)	(496)
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits	15,902	(15,902)				
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-RCVASTR	60,158	(8,066)	52,092	5,708	(3,785)	1,923
1550-LV Variance Account		294,789	294,789		3,740	3,740
1555-Smart Meters Capital Variance Account		(52,558)	(52,558)		(456)	(456)
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes	71,146	63,919	135,065	86,947	3,519	90,465
1563-Account 1563 - Deferred PILs Contra Account	(15,336)	(63,919)	(79,254)	(86,946)	(3,519)	(90,465)
1565-Conservation and Demand Management Expenditures and Recoveries	(433,672)	(95,448)	(529,120)			
1566-CDM Contra Account	433,672	95,448	529,120			
1570-Qualifying Transition Costs	1,971,022	(1,971,022)		504,962	(504,962)	
1571-Pre-market Opening Energy Variance	1,021,006	(1,021,006)				
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	885,016	(1,082,785)	(197,769)	220,779	(162,938)	57,841
1582-RSVAONE-TIME	113,070	(89,673)	23,397	14,933	(12,988)	1,945
1584-RSVANW	(37,744)	(358,555)	(396,298)	91,060	(53,294)	37,766
1586-RSVACN	(909,850)	(257,259)	(1,167,108)	(3,023)	58,508	55,485
1588-RSVAPOWER	2,489,366	(894,339)	1,595,027	1,007,936	(534,241)	473,695
1592-2006 PILs/Taxes Variance						
2425-Other Deferred Credits						
TOTAL	5,893,827	(5,479,121)	414,706	1,859,076	(1,219,407)	639,669

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B5 Deferral / Variance Account Balances

Interest Rate (from sheet Y1) = 3.35%

Deferral / Variance Account	1-Jan-2007 to 31-Dec-2007					
	Open. Principal	Changes	End. Principal	Open. Interest	Changes	End. Interest
1505-Unrecovered Plant and Regulatory Study Costs						
1508-Other Regulatory Assets	230,428		230,428	8,225	14,856	23,081
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail	(23,104)	(22,103)	(45,207)	(496)	(1,621)	(2,117)
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits						
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-RCVASTR	52,092	25,142	77,234	1,923	3,072	4,995
1550-LV Variance Account	294,789	491,024	785,813	3,740	25,140	28,880
1555-Smart Meters Capital Variance Account	(52,558)	(70,291)	(122,849)	(456)	(4,724)	(5,180)
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes	135,065	(48,164)	86,900	90,465	3,845	94,310
1563-Account 1563 - Deferred PILs Contra Account	(79,254)	48,164	(31,090)	(90,465)	(3,845)	(94,309)
1565-Conservation and Demand Management Expenditures and Recoveries	(529,120)	476,540	(52,580)			
1566-CDM Contra Account	529,120	(476,540)	52,580			
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	(197,769)	(508,383)	(706,151)	57,841	18,574	76,416
1582-RSVAONE-TIME	23,397		23,397	1,945	5,367	7,313
1584-RSVANW	(396,298)	(33,266)	(429,565)	37,766	1,740	39,506
1586-RSVACN	(1,167,108)	(796,973)	(1,964,081)	55,485	(32,223)	23,262
1588-RSVAPOWER	1,595,027	431,870	2,026,897	473,695	205,548	679,243
1592-2006 PILs/Taxes Variance						
2425-Other Deferred Credits						
TOTAL	414,706	(482,980)	(68,274)	639,669	235,730	875,399

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B5 Deferral / Variance Account Balances

Interest Rate (from sheet Y1) = 3.35%

Deferral / Variance Account	31-Dec-2007 Balance			1-Jan-08 to 30-Apr-08		
	Principal	Interest	Total	Interest	Other	Balance
1505-Unrecovered Plant and Regulatory Study Costs						
1508-Other Regulatory Assets	230,428	23,081	253,509	4,027		257,536
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail	(45,207)	(2,117)	(47,324)	(729)		(48,053)
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits						
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-RCVASTR	77,234	4,995	82,229	1,245		83,474
1550-LV Variance Account	785,813	28,880	814,693	12,670		827,363
1555-Smart Meters Capital Variance Account	(122,849)	(5,180)	(128,029)	(1,981)		(130,010)
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes	86,900	94,310	181,210	1,401		182,612
1563-Account 1563 - Deferred PILs Contra Account	(31,090)	(94,309)	(125,399)	(1,401)		(126,800)
1565-Conservation and Demand Management Expenditures and Recoveries	(52,580)		(52,580)			(52,580)
1566-CDM Contra Account	52,580		52,580			52,580
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	(706,151)	76,416	(629,736)	2,694		(627,042)
1582-RSVAONE-TIME	23,397	7,313	30,710	1,833		32,542
1584-RSVANW	(429,565)	39,506	(390,059)	892		(389,167)
1586-RSVACN	(1,964,081)	23,262	(1,940,819)	(13,464)		(1,954,283)
1588-RSVAPOWER	2,026,897	679,243	2,706,140	88,443		2,794,583
1592-2006 PILs/Taxes Variance						
2425-Other Deferred Credits						
TOTAL	(68,274)	875,399	807,126	95,631		902,756

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B5 Deferral / Variance Account Balances

Interest Rate (from sheet Y1) = 3.35%

Deferral / Variance Account	1-May-08 to 31-Dec-08			1-Jan-09 to 30-Apr-09		
	Interest	Other	Balance	Interest	Other	Balance
1505-Unrecovered Plant and Regulatory Study Costs						
1508-Other Regulatory Assets	5,905		263,441	2,772		266,213
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail	(1,069)		(49,122)	(502)		(49,623)
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits						
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-RCVASTR	1,826		85,300	857		86,158
1550-LV Variance Account	18,578		845,941	8,721		854,662
1555-Smart Meters Capital Variance Account	(2,904)		(132,914)	(1,363)		(134,278)
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes	2,054		184,666	964		185,630
1563-Account 1563 - Deferred PILs Contra Account	(2,054)		(128,855)	(964)		(129,819)
1565-Conservation and Demand Management Expenditures and Recoveries			(52,580)			(52,580)
1566-CDM Contra Account			52,580			52,580
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	3,950		(623,092)	1,854		(621,238)
1582-RSVAONE-TIME	2,687		35,229	1,261		36,490
1584-RSVANW	1,308		(387,859)	614		(387,245)
1586-RSVACN	(19,741)		(1,974,024)	(9,267)		(1,983,291)
1588-RSVAPOWER	129,678		2,924,261	60,874		2,985,135
1592-2006 PILs/Taxes Variance						
2425-Other Deferred Credits						
TOTAL	140,217		1,042,973	65,821		1,108,794

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B5 Deferral / Variance Account Balances

Interest Rate (from sheet Y1) = 3.35%

Deferral / Variance Account	31-Dec-07 Balance + Interest to 30-Apr-09			1-May-09 to 31-Dec-09		
	31-Dec-07	Interest	Total	Interest	Other	Balance
1505-Unrecovered Plant and Regulatory Study Costs						
1508-Other Regulatory Assets	253,509	12,704	266,213	5,616		271,829
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail	(47,324)	(2,299)	(49,623)	(1,017)		(50,640)
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits						
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-RCVASTR	82,229	3,928	86,158	1,737		87,894
1550-LV Variance Account	814,693	39,969	854,662	17,670		872,332
1555-Smart Meters Capital Variance Account	(128,029)	(6,249)	(134,278)	(2,762)		(137,040)
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes	181,210	4,420	185,630	1,954		187,584
1563-Account 1563 - Deferred PILs Contra Account	(125,399)	(4,420)	(129,819)	(1,954)		(131,773)
1565-Conservation and Demand Management Expenditures and Recoveries	(52,580)		(52,580)			(52,580)
1566-CDM Contra Account	52,580		52,580			52,580
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	(629,736)	8,498	(621,238)	3,757		(617,481)
1582-RSVAONE-TIME	30,710	5,781	36,490	2,556		39,046
1584-RSVANW	(390,059)	2,814	(387,245)	1,244		(386,000)
1586-RSVACN	(1,940,819)	(42,472)	(1,983,291)	(18,777)		(2,002,068)
1588-RSVAPOWER	2,706,140	278,995	2,985,135	123,341		3,108,476
1592-2006 PILs/Taxes Variance						
2425-Other Deferred Credits						
TOTAL	807,126	301,669	1,108,794	133,365		1,242,160

2009 Rate Rider

The calculation of the 2009 Rate Rider for each customer class is presented in the following tables.

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C7 Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	General Service 50 to 4,999 kW - TOU
1508-Other Regulatory Assets	269,618	Distribution Revenue (proposed rates)	166,947	38,421	53,181	
1550-LV Variance Account	865,375	Transmission Connection Revenue	414,412	131,350	312,722	
Sub-Total for recovery	1,134,993		581,359	169,770	365,902	
1590-Recovery of Regulatory Asset Balances (residual)						
Total Recoveries Required (2 years)	1,134,993		581,359	169,770	365,902	
Annual Recovery Amounts	567,496		290,679	84,885	182,951	
Annual Volume			197,649,413	70,476,543	448,543	
Proposed Rate Rider			\$0.0015	\$0.0012	\$0.4079	
per			kWh	kWh	kW	kW

¹ per sheet C6

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C7 Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
1508-Other Regulatory Assets	269,618	Distribution Revenue (proposed rates)	941	18	10,111
1550-LV Variance Account	865,375	Transmission Connection Revenue	935	9	5,948
Sub-Total for recovery	1,134,993		1,876	27	16,059
1590-Recovery of Regulatory Asset Balances (residual)					
Total Recoveries Required (2 years)	1,134,993		1,876	27	16,059
Annual Recovery Amounts	567,496		938	14	8,029
Annual Volume			501,647	17	11,037
Proposed Rate Rider per			\$0.0019 kWh	\$0.8041 kW	\$0.7275 kW

¹ per sheet C6

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C7 Rate Riders						
Allocators	Data Source	2009 Projection Total	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	General Service 50 to 4,999 kW - TOU
Customers / Connections	C1	27,644	18,875	2,365	252	
kWh's	C1	433,981,283	197,649,413	70,476,543	161,192,485	
Distribution Revenue (existing rates)	C4	8,126,204	5,031,902	1,158,373	1,719,309	
Distribution Revenue (proposed rates)	F4	9,265,283	5,737,063	1,320,303	1,827,527	
Transmission Connection Revenue	C2	2,404,377	1,151,411	364,944	868,873	
Approved Recoveries	C5	100.0%	75.5%	12.9%	11.0%	0.4%

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C7 Rate Riders

Allocators	Data Source	2009 Projection Total	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
Customers / Connections	C1	27,644	69	6	6,077
kWh's	C1	433,981,283	501,647	16,635	4,144,560
Distribution Revenue (existing rates)	C4	8,126,204	26,368	216	190,036
Distribution Revenue (proposed rates)	F4	9,265,283	32,323	618	347,448
Transmission Connection Revenue	C2	2,404,377	2,598	26	16,526
Approved Recoveries	C5	100.0%	0.1%	0.0%	0.0%

Method of Recovery

An appropriate allocator (e.g. number of customers, kW's, kWh's) is assigned to each variance/deferral account ("Account"). The projected Account balance as at April 30, 2009 is then apportioned to each customer class based on Test Year volume projections for the allocator. Example: if kWh's are assigned as the allocator for an account, and the Load Forecast for the Test Year indicates that 30% of kWh's will be consumed by the Residential customer class, then 30% of the Account balance is allocated to the Residential class.

For each customer class, the sum of allocated balances over all Accounts selected for disposition is calculated. Example: if two Accounts are selected for disposition and the amounts allocated to the Residential customer class were \$50,000 for Account #1 and \$30,000 for Account #2, then the sum of allocated balances for the Residential class would be \$80,000.

For each customer class, the sum of allocated balances is divided by two to derive the annual recovery amount needed to clear the balances over two years. Example: if the sum of allocated balances for the Residential class is \$80,000, the annual recovery amount to clear the balances over two years would be \$40,000.

For each customer class, the rate rider is calculated as the annual recovery amount divided by the Test Year forecast for the distribution rate volume metric, with the result rounded to the nearest one-hundredth of a cent. Example: if the distribution rate volume metric for the Residential customer class is kWh's, and 100,000,000 kWh's are forecast for the Residential class in the Test Year, then the rate rider for the Residential class would be \$0.0004 ($=\$40,000$ divided by 100,000,000).

Disposition of Variance and Deferral Accounts

WPI seeks recovery of Account 1508 (Other Regulatory Assets) and Account 1550 (LV Variance Account) only. WPI does not seek the recovery of the balance of its deferral and variance accounts pending the outcome of the Board's Generic Hearing on the Disposition of Variance and Deferral Accounts. This methodology is consistent with the recent Decisions of 2008 Cost of Service Applicants.

WPI seeks recovery of Accounts 1508 and 1550 for all amounts including carrying charges up to April 30, 2009. WPI is seeking to recovery the amount of \$1,134,993 over two years, or an amount of \$567,496 per year.

The resulting rate riders for the two year period are shown in the attachment to Exhibit 5, Tab 1, Schedule 3.

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C6 Proposed Deferral /Variance Account Balance Recoveries

Deferral / Variance Account	Recover Balance as at?	Additional Interest to 30 Apr/09?	Balance for Recovery ¹	Additional Interest for Recovery	Total Recovery Amount
1508-Other Regulatory Assets	31 Dec/07	YES	253,509	16,109	269,618
1518-RCVARetail	No Recovery	YES			
1548-RCVASTR	No Recovery	YES			
1550-LV Variance Account	31 Dec/07	YES	814,693	50,682	865,375
1555-Smart Meters Capital Variance Account	No Recovery	YES			
1562-Deferred Payments in Lieu of Taxes	No Recovery	YES			
1563-Account 1563 - Deferred PILs Contra Account	No Recovery	YES			
1565-Conservation and Demand Management Expenditures and Recoveries	No Recovery	YES			
1566-CDM Contra Account	No Recovery	YES			
1580-RSVAWMS	No Recovery	YES			
1582-RSVAONE-TIME	No Recovery	YES			
1584-RSVANW	No Recovery	YES			
1586-RSVACN	No Recovery	YES			
1588-RSVAPOWER	No Recovery	YES			
Sub-Total for Recovery			1,068,202	66,791	1,134,993
1590-Recovery of Regulatory Asset Balances (residual)	No Recovery	NO			
Total Recoveries Required			1,068,202	66,791	1,134,993
Annual Recovery Amounts	# years:	2			567,496

¹ per sheet B5, except account 1590 (sheet C5)

² Interest Rate = 3.35% per sheet Y1

³ Recorded in USA #4405 per sheet C5

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C6 Proposed Deferral /Variance Acc

Deferral / Variance Account	31 Dec/08 Projected Balance	31 Dec/09 Projected Balance	2008 Projected Interest ²	2009 Projected Interest ²
1508-Other Regulatory Assets	263,441	2,211	-9,932	-8,388
1518-RCVARetail	-49,122	-50,640	1,798	1,518
1548-RCVASTR	85,300	87,894	-3,071	-2,594
1550-LV Variance Account	845,941	6,957	-31,248	-26,391
1555-Smart Meters Capital Variance Account	-132,914	-137,040	4,885	4,126
1562-Deferred Payments in Lieu of Taxes	184,666	187,584	-3,456	-2,918
1563-Account 1563 - Deferred PILs Contra Account	-128,855	-131,773	3,456	2,918
1565-Conservation and Demand Management Expenditures and Recoveries	-52,580	-52,580		
1566-CDM Contra Account	52,580	52,580		
1580-RSVAWMS	-623,092	-617,481	-6,644	-5,611
1582-RSVAONE-TIME	35,229	39,046	-4,520	-3,817
1584-RSVANW	-387,859	-386,000	-2,200	-1,858
1586-RSVACN	-1,974,024	-2,002,068	33,205	28,044
1588-RSVAPOWER	2,924,261	3,108,476	-218,121	-184,215
Sub-Total for Recovery	1,042,973	107,167	-235,848	-199,186
1590-Recovery of Regulatory Asset Balances (residual)	73,311	832,447	-7,611	-2,474
Total Recoveries Required				6,337
Annual Recovery Amounts	# years:			
Interest Totals: ³			-243,459	-195,324

¹ per sheet B5, except account 1590 (sheet C5)

² Interest Rate = 3.35% per sheet Y1

³ Recorded in USA #4405 per sheet C5

Overview of Cost of Capital and Rate of Return

The purpose of this evidence is to summarize the method and cost of financing the Applicant's capital requirements for the 2009 test year.

Capital Structure

The Applicant has a current capital structure of 53.3% debt, 46.7% equity, as approved by the Ontario Energy Board in EB-2007-0865, and a return on equity of 9.00%, consistent with the return specified in the Board's Decision in RP-2005-0020/EB-2005-0434, dated June 15, 2006. WPI is requesting Board approval of a capital structure of 56.67% debt, 43.33% equity including an equity return of 8.57%.

This change in capital structure complies with the Ontario Energy Board's Report on Cost of Capital and 2nd Generation Incentive Regulation of Ontario Electricity Distributors dated December 20, 2006. The Ontario Energy Board Report indicates that Distributors will be required to phase-in a 60% debt and 40% equity capital structure that must be completed by 2010. The Applicant is requesting this change in capital structure and associated return on equity primarily to support the Report of the Board. The Applicant believes the requested capital structure and equity return will provide continued access to long-term debt at reasonable rates.

Cost of Debt

Exhibit 6, Tab 1, Schedule 2 provides the detailed calculation of The Applicant's forecast long-term debt costs. Long-term debt cost information for the historical and bridge periods is also filed at Exhibit 6, Tab 1, Schedule 2.

Return on Equity

The Applicant's requested return on equity of 8.57% for 2009 test years is summarized below. The methodology of calculating the ROE is based on the "Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors" issued by the Ontario Energy Board December 20, 2006, Exhibit 6, Tab 1, Schedule 3 provides the excerpt from the report. The ROE in this application has been updated to reflect the maximum allowed ROE as addressed in the "Cost of Capital Parameter Updates for 2008 Cost of Service Applications" issued by the Board Secretary on March 7, 2008.

ROE as per Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors" issued by the Ontario Energy Board December 20, 2006

Government of Canada Bond Yields	
3-month forecast of the 10-year bond yield	4.60%
12-month forecast of the 10-year bond yield	4.80%
Average actual prior month 30-year bond yield	4.03%
Average actual prior month 10-year bond yield	4.12%
Long Canada Bond Forecast (LCBF)	4.61%
Return On Equity	8.68%

Updated ROE as per "Cost of Capital Parameter Updates for 2008 Cost of Service Applications" issued by the Board Secretary on March 7, 2008

Ten Year Government of Canada Bond Yield – end of April 2008	4.0%
Ten Year Government of Canada Bond Yield – end of April 2008	4.4%
Average of three and twelve month forecasts	4.2%
Add the average spread between 30 year and 10 year Government of Canada Bonds for all business days in January 2008 as posted by the Bank of Canada	0.256%
Equals the forecasted yield on Long-term Government of Canada Bonds	4.456%
Per the mathematical formula documented in Exhibit 6, Tab 1, Schedule 3:	
Updated ROE calculated as: $9.35\% + (0.75 \times (4.456\% - 5.50\%))$	8.567%
Maximum Allowed ROE (rounded to two decimal places)	8.57%

Cost of Debt

The notes payable to shareholders are at a rate of 5.47%; interest payable quarterly, due on demand. The shareholder notes are only due on demand to the extent the shareholder requests payment ninety days prior to the year end. In the event a request is made, the Applicant is obligated to repay this shareholder during the following fiscal year. No repayments are required without a written request. At the time of this application, there were no written requests from the shareholders.

The applicant entered into an interest rate swap arrangement on a notional principle amount of \$5,655,638 as at June 30, 2007 maturing June 28, 2022. The swap is a receive-variable, pay-fixed swap with CIBC World Markets. The swap agreement bears interest at a rate of 5.33% plus a stamping fee of 0.80% payable in blended monthly installments of \$48,700.

The applicant entered into an interest rate swap arrangement on a notional principle amount of \$2,500,000 as at July 3, 2007 maturing July 3, 2027. The swap is a receive-variable, pay-fixed swap with CIBC World Markets. The swap agreement bears interest at a rate of 5.38% plus a stamping fee of 0.80% payable in blended monthly installments of \$18,150.

Cost of debt for historic years, 2008 bridge year and 2009 test year are presented in the following table.

	2006 Board Approved			2006 Actual			2007 Actual			2008 Bridge			2009 Test		
Long Term Debt	Principle	Carrying Costs	Calculated Cost Rate	Average Principle	Carrying Costs	Actual Cost Rate	Average Principle	Carrying Costs	Calculated Cost Rate	Average Principle	Carrying Costs	Calculated Cost Rate	Average Principle	Carrying Costs	Calculated Cost Rate
Shareholders	8,616,765.00	5.11%	440,316.69	6,218,923.00	5.47%	332,847.16	5,422,174.88	5.47%	295,408.91	5,260,461.00	5.47%	287,747.22	5,260,461.00	5.47%	287,747.00
Town of Minto	10,400.00	5.11%	531.44												
CIBC	183,292.00	5.11%	9,366.22												
CIBC	1,236,560.00	5.11%	63,188.22												
CIBC	717,619.00	5.11%	36,670.33												
CIBC	223,376.00	5.11%	11,414.51												
CIBC	1,155,225.00	5.11%	59,032.00												
CIBC				1,104,707.41											
CIBC				834,622.89	10.12%	84,468.84									
CIBC				524,767.28	7.87%	41,292.66									
CIBC				2,872,164.24	3.81%	109,555.84	5,639,510.98	6.03%	339,828.24	5,408,058.75	6.18%	331,130.51	2,370,478.00	6.18%	146,445.00
CIBC				275,000.00	0.18%	497.26	1,511,622.00	5.87%	88,778.14	2,439,699.50	6.13%	150,471.00	5,146,804.00	6.13%	315,161.00
Other Long Term Debt													1,008,219.00	5.23%	52,730.00
	<u>\$ 12,143,237.00</u>		<u>\$ 620,519.41</u>	<u>\$ 11,830,184.81</u>		<u>\$ 568,661.76</u>	<u>\$ 12,573,307.86</u>		<u>\$ 724,015.29</u>	<u>\$ 13,108,219.25</u>		<u>\$ 769,348.73</u>	<u>\$ 13,785,962.00</u>		<u>\$ 802,083.00</u>
		5.11%				4.81%			5.76%			5.87%			5.82%

Return on Equity

The calculations used to determine the return on equity and the debt are taken from the "Report to the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors" issued December 20, 2006.

Excerpt from the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors Appendix A and Appendix B

Method to Update the Deemed Long-term Debt Rate

The Board will use the Long Canada Bond Forecast plus an average spread with "A/BBB" rated corporate bond yields to determine the updated deemed debt rate.

The following approach is consistent with the ROE method. As per the approach adopted in the 2006 EDRH, the ROE and the long-term debt rates are based on the same risk-free rate forecast. Therefore, they differ only through the risk premiums that reflect their distinct natures and for which lenders/investors seek commensurate returns. This approach simplifies the calculations and aims to make it easier to understand the numbers. Specifically, the Long Canada Bond Forecast (*LCBf*) used will be the same as that used for updating the ROE. The average spread between "A/BBB" rated corporate bond yields and 30-year (long) Government of Canada Bond yields will be calculated as the average spread over the weeks of the month corresponding to the Consensus Forecasts.

The deemed Long-Term Debt Rate (*LTDR*) will be calculated as follows:

$$LTDR_t = LCBF_t + \frac{\sum_w (CorpBonds_{w,t} - {}_{30}CB_{w,t})}{n}$$

Where:

CorpBonds w,t is the average long-term corporate bond yield from Scotia Capital Inc. for week w of period t [Series V121761];

${}_{30}CB_{w,t}$ is the 30-year (long) Government of Canada bond yield for week w of period t [Series V121791]; and

n is the number of weeks in the month for which data are reported.

Method to Update ROE - ROE Update for any Period

Using March 1999 as the starting calculation and substituting for the initial ROE and Long Canada Bond Forecast approved by the Board in the Decision RP-1998-0001 the following is the adjustment formula for calculating the ROE at time t :

$$ROE_t = 9.35\% + 0.75 \times (LCBF_t - 5.50\%)$$

The ROE must be set in advance of the approved rates. The final ROE will be factored into rates using the Long Canada Bond Forecast based on *Consensus Forecasts* (as detailed below) and Bank of Canada data three months in advance of the effective date for the rate change. Therefore, for May 1 rate changes, the ROE will be based on January data – effectively *Consensus Forecasts* published during that month and Bank of Canada data for all business days during the month of January. The necessary data is available within the first or second business days after the end of the month and thus poses no delay for determining rates.

Long Canada Bond Forecast for any Period

For any period t the Long Canada Bond Forecast $LCBF_t$ can be expressed as:

$$LCBF_t = \left[\frac{{}_{10}CBF_{3,t} + {}_{10}CBF_{12,t}}{2} \right] + \frac{\sum_i ({}_{30}CB_{i,t} - {}_{10}CB_{i,t})}{I_t}$$

Where:

${}_{10}CB_{3,t}$ is the 3-month forecast of the 10-year Government of Canada bond yield as published in *Consensus Forecasts* at time t ;

${}_{10}CB_{12,t}$ is the 12-month forecast of the 10-year Government of Canada bond yield as published in *Consensus Forecasts* at time t ;

${}_{30}CB_{i,t}$ is the actual rate for the 30-year Government of Canada bond yield at the close of day i (as published by the Bank of Canada) [Series V39056] during the month (this is the previous month data, the same as used for updating the ROE for natural gas distribution) corresponding to time t ;

${}_{10}CB_{i,t}$ is the actual rate for the 10-year Government of Canada bond yield at the close of day i (as published by the Bank of Canada) [Series V39055] during the month corresponding to time t ; and

I_t is the number of business days for which published 10- and 30- Government of Canada bond yields are published during the month corresponding to time t .

The Return on Equity has been updated as per letter from the Board Secretary dated March 7, 2008 entitled "Cost of Capital Parameter Updates for 2008 Cost of Service Applications" and evidenced in Exhibit 6, Tab 1, Schedule 1.

Calculation of Cost by Item from Test Year

As it can be seen in the attachment to Exhibit 6, Tab 1, Schedule 2, the cost of debt for 2009 test year is 5.82%.

In calculating the forecast costs by item, WPI has used the average principal balances for the years reported. The carrying costs on Long Term debt are based on the actual rates where known at the date of this application. It is anticipated that the Applicant will need to secure approximately \$2,000,000 of additional financing in the 2009 Test year. For the purposes of this application, the Applicant has used an interest rate of 5.23%. The rate of 5.23% was as quoted by CIBC on June 23, 2008 for a 15 year interest rate SWAP arrangement. The Applicant reserves the opportunity to update this rate prior to the Board issuing its rate order should it have a material affect on this application.

WPI is requesting Board approval of a capital structure of 56.67% debt, 43.33% equity including an equity return of 8.57% for the 2009 test year.

Calculation of Return on Equity and Debt

	Deemed Portion	Effective Rate	Average Cost of Capital
Short-Term Debt	4.00%	4.47%	0.18%
Long-Term Debt	52.67%	5.82%	3.07%
Total Equity	43.33%	8.57%	3.71%
Regulated Rate of Return	100.00%		6.96%

Attached to this section is presented a table with data on capital structure, cost of common equity and cost of debt for the historic years, the 2008 bridge year and 2009 test year.

2006 Board Approved

		Capital Structure			
		Actual	Deemed	Cost Rate	Return
Long Term Debt	\$ 6,853,959	23.9%			
Unfunded Short Term Debt	\$ 5,289,278	18.5%			
Total Debt	\$ 12,143,237	42.4%	50.0%	5.11%	
Preference Shares					
Common Equity	\$ 16,475,550	57.6%	50.0%		9.00%
	<u>\$ 28,618,787</u>				

2006 Actual

		Capital Structure			
		Actual	Deemed	Cost Rate	Return
Long Term Debt	\$ 11,830,184	39.8%			
Unfunded Short Term Debt		0.0%			
Total Debt	\$ 11,830,184	39.8%	50.0%	5.11%	
Preference Shares					
Common Equity	\$ 17,870,051	60.2%	50.0%		9.00%
	<u>\$ 29,700,235</u>				

2007 Actual

		Capital Structure			
		Actual	Deemed	Cost Rate	Return
Long Term Debt	\$ 12,573,307	40.0%			
Unfunded Short Term Debt		0.0%			
Total Debt	\$ 12,573,307	40.0%	50.0%	5.11%	
Preference Shares					
Common Equity	\$ 18,828,371	60.0%	50.0%		9.00%
	<u>\$ 31,401,678</u>				

2008 Bridge

		Capital Structure			
		Actual	Deemed	Cost Rate	Return
Long Term Debt	\$ 13,108,219	38.7%			
Unfunded Short Term Debt		0.0%			
Total Debt	\$ 13,108,219	38.7%	53.3%	5.11%	
Preference Shares					
Common Equity	\$ 20,753,171	61.3%	46.7%		9.00%
	<u>\$ 33,861,390</u>				

2009 Test

		Capital Structure			
		Actual	Deemed	Cost Rate	Return
Long Term Debt	\$ 13,785,962	37.1%	4.0%	4.47%	
Unfunded Short Term Debt		0.0%	52.7%	5.82%	
Total Debt	\$ 13,785,962	37.1%			
Preference Shares					
Common Equity	\$ 23,340,584	62.9%	43.3%		8.57%
	<u>\$ 37,126,546</u>				

Overview of Calculation or Revenue Deficiency of Surplus

This exhibit provides an overview of the revenue deficiency or surplus calculation process used to project the revenue required by WPI to continue to provide safe and reliable service to its customers.

WPI projects that it will recover \$8,442,147 in Distribution Revenue in the 2009 Test Year through distribution rates and other regulated charges at existing rates. At the existing rates as per the EB-2007-0865 Decision and Order issued April 17, 2008, WPI's gross revenue deficiency would be **\$1,462,691** as calculated in Exhibit 7, Tab 1, Schedule 2.

The 2009 Net Revenues includes:

\$7,802,592 recovered through fixed and variable distribution rates;

\$639,555 recovered through Administration, Specific Service Charges and Other Miscellaneous Revenue, and;

\$30,000 in interest and dividend income

The 2009 Net Revenues excludes:

\$253,892 in Hydro One pass-through Low Voltage Charges

\$69,720 in Transformer Allowance Costs

These exclusions are discussed in more detail in Exhibit 9.

Determination of Revenue Deficiency or Surplus

Gross Deficiency or Sufficiency in Revenues

The forecasted revenue deficiency of \$1,462,691 is mainly attributable to the substantial increase in capital investment and the resulting rate of return on capital as described in Exhibit 2 and Exhibit 6, Tab 1, Schedule 3, respectively. The projected rate base of \$33,630,199 is an increase of \$8,532,601 from the 2006 EDR Approved rate base. Of this amount, \$8,053,882 is directly attributable to the net capital additions by WPI. WPI remains committed to providing a safe and reliable distribution system for its customers, the public and its employees, and as such has invested substantial capital into its distribution plant as outlined in Exhibit 2, Tab 3.

Total net revenues have been projected to decrease by approximately \$44,000 from 2008 to 2009 due to projected decreases in interest revenue and revenues from jobbing. Overall there is a less than \$4,000 increase from the 2006 EDR Approved OM&A expenses to the 2009 Test Year. This equates to a less than 0.08% increase in OM&A expenses since 2004.

Overall the results of the revenue deficiency as calculated in Exhibit 7, Tab 1, Schedule 2, reflect the lack of return in the period leading up to this application.

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G7 Variance Analysis: Revenue Sufficiency / Deficiency

	2009 Projection	2008 Projection	Var #	Var %
Utility Income <i>(see below)</i>	1,317,573	1,037,544	280,029	27.0%
Utility Rate Base <i>from sheet G6</i>	33,630,199	32,298,421	1,331,779	4.1%
Indicated Rate of Return	3.92%	3.21%	0.71%	22.0%
Requested / Approved Rate of Return <i>from sheet D3</i>	6.96%	6.96%		
Sufficiency / (Deficiency) in Return	(3.04%)	(3.74%)	0.71%	18.8%
Net Revenue Sufficiency / (Deficiency)	(1,021,971)	(1,209,352)	187,382	15.5%
Provision for PILs/Taxes *	(440,720)	(1,195,912)	755,192	63.1%
Gross Revenue Sufficiency / (Deficiency)	(1,462,691)	(2,405,264)	942,574	39.2%
Deemed Overall Debt Rate <i>from sheet D3</i>	5.72%	5.11%	0.61%	12.0%
Deemed Cost of Debt <i>from sheet D3</i>	1,090,630	825,225	265,405	32.2%
Utility Income less Deemed Cost of Debt	226,943	212,319	14,624	6.9%
Return On Deemed Equity	1.56%	1.52%	0.04%	2.7%

UTILITY INCOME *from sheets E1 & E2 (except PILS / Income Taxes)*

Total Net Revenues	8,472,147	8,468,376	3,771	0.0%
OM&A Expenses	4,811,825	4,858,515	(46,690)	(1.0%)
Depreciation & Amortization	1,829,713	1,720,456	109,257	6.4%
Taxes other than PILs / Income Taxes	56,600	50,600	6,000	11.9%
Total Costs & Expenses	6,698,138	6,629,571	68,567	1.0%
Utility Income before Income Taxes / PILs	1,774,009	1,838,805	(64,796)	(3.5%)
PILs / Income Taxes <i>from sheet E4</i>	456,436	801,261	(344,825)	(43.0%)
Utility Income	1,317,573	1,037,544	280,029	27.0%

* In 2009: difference between amounts on sheet E4 for 2009 at existing rates vs. 2009 at new revenue requirement;
 in 2008: Net Sufficiency / (Deficiency) multiplied by grossed-up effective tax rate on Utility Income.

Cost Allocation Overview

Introduction

On September 29, 2006 the Ontario Energy Board (the "OEB") issued the Board Directions on Cost Allocation Methodology for Electricity Distributors ("the Directions"). On November 15, 2006 the OEB also issued the Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model ("the Model") and User Instruction (the Instructions") for the Model. WPI prepared its information filing consistent with WPI's understanding of the Directions, the Guidelines, the Model and the Instructions and submitted it to the Board on March 31, 2006.

The main purpose of this cost allocation filing was to provide evidence to show WPI's rate classifications that are being subsidized by other classes and those rate classifications that are over contributing based on the assumptions of the Model.

Background

In the mid 1980's, Ontario Hydro, the regulator at the time, completed the last cost allocation study. This study included the distribution function as part of an integrated cost study. The integrated study reviewed the full costs of providing electricity to customers which included energy, transmission and distribution. Distribution represented only around 15% of the total costs reviewed. The results of this study assisted Ontario Hydro in developing the Rate Setting Guidelines that were used by Municipal Electric Utilities to develop the bundled rates they charged customers prior to industry restructuring.

Under the Energy Competition Act, 1998, the electricity industry in Ontario was separated into Generation, Transmission and Distribution companies. Along with this separation the rates also needed to be unbundled to reflect the structure of the new companies. The unbundling of distribution from generation and transmission was completed in the 2000 to 2001 timeframe using the Electricity Distribution Rate Handbook Rate and the Rate Unbundling and Design Model (i.e. the RUD model). The Rate Handbook and RUD model provided a method to unbundle distribution rates from the other rates by rate classification but it did not determine

1 whether the unbundled rates recovered the cost of providing service to each rate class. The
2 2006 cost allocation filings is the first time a cost allocation study has been conducted in Ontario
3 that determines whether or not the distribution rates charged each customer class are
4 recovering the distribution costs that are allocated to each class.

5
6 For purposes of the 2006 Cost Allocation filing:

- 7
- 8 • Westario used the Board approved 2006 EDR, RP-2005-0020/EB-2005-0344, as the
- 9 sole basis for costs and revenue components.
- 10 • Westario was a historical test year filer in the 2006 EDR.
- 11 • Westario is a Wholesale Market Participant.
- 12 • Westario utilized the services of Hydro One Networks Inc. as its load data provider.
- 13 • Westario did not undertake an updated residential appliance saturation survey. In lieu of
- 14 the appliance saturation survey, two years of load data was provided to load data
- 15 provider, Hydro One Networks.
- 16 • Westario has utilized the weather normalization data provided by its load data provided,
- 17 Hydro One Networks.
- 18 • Westario utilized the generic minimum system approach incorporated into the Board's
- 19 Allocation Model.
- 20 • Westario utilized the Peak Load Carrying Capability Adjustment incorporated into the
- 21 Board's Allocation Model.
- 22 • Westario did not supplement or adjust the Board approved methodology or the Board's
- 23 Cost Allocation Model.
- 24 • Westario completed Run 1 of the Cost Allocation Model incorporating the 2006 EDR
- 25 rates only. The 2006 EDR rates are:
 - 26 o Residential
 - 27 o General Service less than 50 kW
 - 28 o General Service 50 to 4,999 kW
 - 29 o General Service 50 to 4,999 kW – Time of Use
 - 30 o Unmetered Scattered Load
 - 31 o Sentinel Lighting

1 o Street Lighting

- 2 • Westario had a separate approved distribution rate for unmetered scattered load ("USL")
3 prior to the 2006 EDR and received approval in the 2006 EDR of monthly fixed and
4 variable charges. Therefore, the USL class has modeled separately in Run 1 and Run 2.
5 There is only one non-photo sensitive USL identified in Westario.
- 6 • Westario received approval in its 2006 EDR for a General Service Greater than 50 kW –
7 Time of Use rate class. This rate class was modeled separately in RUN 1 and combined
8 with the General Service greater than 50 kW class in Run 2. This distinction is the only
9 change Westario made between Run 1 and Run 2; Westario did not file an optional Run
10 3.

11 **Current Cost Allocation Study**

12 On the advice of ERA, Westario assessed the need to complete an updated cost allocation
13 study on the basis of stability of Westario's infrastructure, operations, customer count and the
14 class shares of billed kWh and kW. The premise underlying this approach is that if the
15 underlying costs and allocators are stable, the proportional allocation of costs to the rate classes
16 will not have changed significantly from the results of the 2006 Cost Allocation Model. In that
17 case, it will be reasonable to use the percentage allocations to the rate classes that were
18 derived in the 2006 cost allocation as a suitable proxy for the 2009 allocators.

19

20 The information on Westario's rate base Exhibit 2 and operating and maintenance costs Exhibit
21 4 show that the underlying infrastructure and operations have been quite stable through the
22 intervening years. Further Exhibit 3 shows that the customer count has also been stable. Tables
23 1 and 2, at the end of this Schedule, show the 2006 EDR Approved and 2009 forecast class
24 shares of billed kWh and kW. These tables show that the usage is also stable.

25

26 ERA reviewed the reclassification of overhead wire to underground referred to as Exhibit 2, Tab
27 2, Schedule 3 pages 23 and 24 and has advised WPI that this reclassification has no impact on
28 the cost allocation study as both accounts are functionalized, classified and allocated in an
29 identical manner.

30

Westario concurs with ERA's advice that Westario's infrastructure, operations, customer count and the class shares of billed kWh and kW are sufficiently stable relative to the acceptable revenue-to-cost ratio ranges recommended by the Board in *Application of Cost Allocation for Electricity Distributors, Report of the Board* (EB-2007-0667) that it would not be prudent to incur the cost of completing a full cost allocation study for the 2009 test year. The factors that were considered in making this determination were:

- the proportions of kWh and kW attributable to each rate class have not changed significantly between the 2006 EDR approved shares and the 2009 forecast, hence, the share of costs attributable to each class will not have changed significantly;
- Westario's capital and operating cost do not exhibit any significant discontinuities;
- the revenue-to-cost ratios for all classes are within the Board-approved ranges except streetlighting (which is being increased from a revenue-to-cost ratio of 50% to 75% in the Test Year); hence, small changes in the calculated revenue-to-cost ratios would not require changes in the proposed rates;
- Westario will be implementing smart meters in the near future, which will provide a significantly improved basis (e.g., a direct measure of the hourly demand of each rate class) for quantifying the allocators used in the cost allocation study than the Hydro One estimates that must be relied on at this time; hence, it is prudent to defer updating Westario's cost allocation study until this information is available;
- Time-of-use commodity pricing can be expected to alter demand and, as a result, some key allocators used in cost allocation studies; hence, it would be prudent to defer updating Westario's cost allocation study until the new patterns of use can be reflected in the study; and
- it is expected that the Board's current Rate Design Review will result in changes to rate classes necessitating new cost allocation studies; hence, an updated cost allocation study will be required in the near-future in any case.

Updating Westario's cost allocation would require a significant investment of time and money to obtain an updated hourly load shape by class, and then update the cost allocation model with 2009 forecast cost information. If Westario were to conduct a cost allocation study for the 2009 test year, it would be quickly out-of-date due to the imminent industry and regulatory changes

noted above. For these reasons, Westario determined that it was prudent to defer updating its cost allocation study until its next cost of service rate application is filed.

Table 1

Customer Class Name	2006 EDR Approved kWh	Share by Class	2009 Normalized	Share by Class
Residential	203,562,663	46.91%	197,649,413	45.54%
General Service Less Than 50 kW	70,522,040	16.25%	70,476,543	16.24%
General Service 50 to 4,999 kW	152,787,963	35.21%	161,192,485	37.14%
General Service 50 to 4,999 kW - TOU	1,653,261	0.38%	0	0.00%
Unmetered Scattered Load	538,256	0.12%	501,647	0.12%
Sentinel Lighting	13,229	0.00%	16,635	0.00%
Street Lighting	4,824,146	1.11%	4,144,560	0.96%
TOTAL	433,901,558	100.00%	433,981,283	100.00%

Table 2

Customer Class Name	2006 EDR Approved kW	Share by Class	2009 Normalized	Share by Class
General Service 50 to 4,999 kW	452,234	95.87%	448,543	97.59%
Sentinel Lighting	39	0.01%	17	0.00%
Street Lighting	13,579	2.88%	11,037	2.40%
TOTAL	471,736	100.00%	459,597	100.00%

Summary of Results and Proposed Changes

The results of a cost allocation 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 shows 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 collecting and is being subsidized by other classes. A percentage of greater than 100% indicates the rate classification is over collecting the cost assigned to the classification and is subsidizing other classes.

The following table outlines the revenue to cost ratios for Run 2. The results for Run 1 are similar to those in Run 2 with the exception of the General Service > 50-4,999 kW rate classification. In Run 2, the General Service > 50 kW – 4,999 kW TOU was combined with the General Service > 50 – 4,999 kW rate classification. As a result, the cost to revenue ratio in Run 1 for General Service > 50 – 4,999 kW was 170.13% and the cost to revenue ratio for General Service > 50 – 4,999 kW - TOU customers was 11.08%. All other ratios in Run 1 are essentially the same as Run 2.

Rate Classification	Revenue to Cost Ratio	(\$ Being Subsidized)/ \$ Over Contributing
Residential	94.75%	(\$290,876)
GS <50 kW	80.77%	(\$285,129)
GS >50 - 4,999 kW	168.03%	\$671,245
Street Light	50.04%	(\$203,734)
Sentinel	99.35%	(\$4)
Unmetered Scattered Load	100.39%	\$128

The above results suggest that the General Service > 50 – 4,999 kW rate classification is subsidizing the Residential, General Service <50 kW, Street Light and Unmetered Scattered Load rate classifications.

With the exception of the Street Lighting rate classification; all other rate classifications are within the Target Floor and Ceiling Ranges as established by Board Staff Discussion Paper

(EB-2007-0667). WPI proposes to begin adjusting the allocations of revenue among its rate classes in order to work towards the elimination of cross-subsidization. This will involve increasing the proportion of revenue for which the Street Lighting and Sentinel rate classifications are responsible for and decreasing the proportion of revenue that GS > 50 – 4,999 kW is responsible for.

The existing and proposed revenue/cost ratios are as follows:

Customer Class Name	Rate Application (2009 Test Year)			Cost Allocation Revenue to Cost Ratio	Target Range		
	Allocated Revenues	Allocated Costs	Revenue to Cost Ratio		Variance	Floor	Ceiling
Residential	5,737,063	6,043,739	94.93%	94.75%	0.18%	85.00%	115.00%
General Service Less Than 50 kW	1,320,303	1,626,579	81.17%	80.77%	0.40%	80.00%	120.00%
General Service 50 to 4,999 kW	1,827,527	1,099,079	166.28%	168.03%	-1.75%	80.00%	180.00%
Unmetered Scattered Load	32,323	32,323	100.00%	100.39%	-0.39%	80.00%	120.00%
Sentinel Lighting	618	618	100.00%	99.35%	0.65%	70.00%	120.00%
Street Lighting	347,448	462,945	75.05%	50.04%	25.01%	70.00%	120.00%
TOTAL	9,265,283	9,265,283					

Rate Design Overview

This exhibit documents the calculation of WPI's proposed distribution rates by rate class for the 2009 test year, based on the allocation of revenue proposed in Exhibit 8 – Cost Allocation.

WPI has determined its total 2008 base service revenue requirement to be \$9,828,002. The total revenue offset in the amount of \$669,555 reduces WPI's total service revenue requirement to a base revenue requirement to \$9,158,447, which is used to determine the proposed distribution rates. The base revenue requirement is derived from WPI's 2009 capital and operating forecasts, weather normalized usage, forecasted customer counts, and WPI's regulated return on rate base. The base revenue requirement is further adjusted by a total of \$803,197 for the Transformer Allowance and the Low Voltage costs from Hydro One Networks Inc. The base revenue requirement is summarized in Table 1 below.

Table 1 – Calculation of Base Revenue Requirement

Description	Amount
OM&A Expenses	4,868,425
Amortization Expense	1,829,713
Total Distribution Expenses	6,698,138
Regulated Return On Capital	2,339,543
PILs (with gross-up)	897,156
Service Revenue Requirement	9,934,837
Less: Revenue Offsets	669,555
Base Revenue Requirement	9,265,283
Transformer Allowance	69,720
Low Voltage - from Hydro One	733,477
Adjusted Base Revenue Requirement	10,068,480

Determination of Monthly Fixed Charges

WPI's current OEB-approved monthly fixed charges based on its 2008 IRM application, and before the smart meter adder, by customer class are summarized in Table 2 below.

Table 2 – Current Monthly Fixed Charges

Customer Class Name	
Residential	\$10.61
General Service Less Than 50 kW	\$19.46
General Service 50 to 4,999 kW	\$239.89
General Service 50 to 4,999 kW – TOU	\$43.68
Unmetered Scattered Load	\$4.40
Sentinel Lighting	\$1.35
Street Lighting	\$2.31

In September 2006 the OEB completed its Cost Allocation Review and issued the Board Directions on Cost Allocation Methodology for Electricity Distributors, RP-2005-0317. The results of this Board report stem from at least three years of discussions and work groups which included OEB staff, electricity distributors, intervenors and experts at various stages of the review process. Subsequently, in November of 2006, the OEB issued the Cost Allocation Informational Filing Guidelines for Electricity Distributors (“the Guidelines”) and the Cost Allocation Model. The Guidelines and Model provided LDCs the framework to complete their cost allocation studies which were filed in early 2007.

In its November 28, 2007 Report of the Board, 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) of the bill. At page 12 of the Report, the OEB determined that the floor amount for the Monthly Service Charge 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. WPI’s Monthly Service Charges exceed that floor amount with the exception of the Unmetered Scattered Load rate classification. With respect to the upper bound for the Monthly Service Charge, the OEB considered it to be inappropriate to make changes to the Monthly Service Charge 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-2007-0031). Although the OEB indicated that for the time being, it does not expect distributors to make changes to the Monthly Service Charge that result in a charge that is greater than the ceiling as defined in the Methodology for the Monthly Service Charge; and that distributors that are currently above that value are not required to make changes to their current Monthly Service Charge to bring it to or below that

level at this time; WPI is proposing to keep the General Service 50 to 4,999 kW rate classification at its' current level as it is equal to the ceiling amount as determined by WPI's cost allocation filing.

Table 3 below provides WPI's calculations of its proposed fixed/variable split for the 2009 Test Year.

Table 3 – Current and Proposed Fixed/Variable Split

	Current		Proposed		Difference	
	Fixed	Variable	Fixed	Variable	Fixed	Variable
Residential	47.76%	52.24%	47.76%	52.24%	0.00%	0.00%
General Service Less Than 50 kW	47.68%	52.32%	47.68%	52.32%	0.00%	0.00%
General Service 50 to 4,999 kW	42.19%	57.81%	33.55%	66.45%	-8.64%	8.64%
Unmetered Scattered Load	13.82%	86.18%	27.98%	72.02%	14.16%	-14.16%
Sentinel Lighting	45.09%	54.91%	45.09%	54.91%	0.00%	0.00%
Street Lighting	88.64%	11.36%	88.64%	11.36%	0.00%	0.00%

WPI's proposed monthly fixed charges based on it's the proposed fixed/variable split, and before the smart meter adder, by customer class are summarized in Table 4 below.

Table 4 – Proposed Monthly Fixed Charges

Customer Class Name	
Residential	\$12.84
General Service Less Than 50 kW	\$24.05
General Service 50 to 4,999 kW	\$239.89
Unmetered Scattered Load	\$11.19
Sentinel Lighting	\$3.92
Street Lighting	\$4.28

As proposed above, Residential, General Service Less than 50kW, Unmetered Scattered Load, Sentinel Lighting and Street Lighting rate categories' monthly fixed charges would increase. With the exception of the Unmetered Scattered Load, this change is due to an increase in the revenue requirement, not a marked change in the percentage split between fixed and variable allocated costs.

The increase in the proposed monthly fixed charge for the Unmetered Scattered Load rate category is as a result of bringing the fixed monthly charge to the floor level as appropriate under the cost allocation methodology.

The proposed General Service 50 to 4,999 kW monthly fixed charge remains unchanged as its' current level is the same as that of the ceiling level under the cost allocation methodology.

Table 5 below provides WPI's calculations of its proposed monthly fixed distribution charges for the 2009 Test Year.

Table 5 – Proposed Fixed Distribution Charge

Customer Class Name	Rate	Volume 1	Revenue 2
Residential	\$12.84	226,500	\$2,908,260
General Service Less Than 50 kW	\$24.05	28,380	\$682,539
General Service 50 to 4,999 kW	\$239.89	3,024	\$725,427
Unmetered Scattered Load	\$11.19	828	\$9,265
Sentinel Lighting	\$3.92	72	\$282
Street Lighting	\$4.28	72,924	\$312,115
TOTAL		331,728	4,637,889

1 Fixed Charge = # Customers (Connections) multiplied by 12 (months)
2 Rate x Volume

The variable distribution charge is calculated by dividing the variable distribution revenue requirement by the appropriate 2009 Test Year usage, kWh or kW, as the class charge determinant and applying adjustments relating to Transformer Allowance for the General Service > 50 kW customer class and Low Voltage Charges.

The amount of Transformer Allowance expected to be provided to those General Service 50 – 4,999 kW customers that own their transformers has been included in the General Service 50 – 4,999 kW volumetric charge. This means the General Service 50 – 4,999 kW volumetric charge has been increased by the amount of the Transformer Allowance. Once the Transformer Allowance is applied to this charge the resulting revenue will recover the full base revenue requirement for the General Service 50 – 4,999 kW rate class.

The Low Voltage charges from Hydro One Networks Inc. are a pass thru charge that is included in WPI's proposed Adjusted Base Revenue Requirement. The allocation of these charges are not based on the same methodology as the cost allocation, but on a proportionate rate based on Transmission-Connection Charges. Table 6 provides a breakdown of the proposed allocation of Low Voltage charges.

Table 6 – Proposed Allocation of Low Voltage Charges

Customer Class Name	Test Year Revenues Transmission - Connection	Class Share	Low Voltage Charges
Residential	1,151,411	47.89%	351,248
General Service Less Than 50 kW	364,944	15.18%	111,330
General Service 50 to 4,999 kW	868,873	36.14%	265,058
Unmetered Scattered Load	2,598	0.11%	792
Sentinel Lighting	26	0.00%	8
Street Lighting	16,526	0.69%	5,041
TOTAL	2,404,377	100.00%	733,477

Table 7 below summarizes both the proposed fixed distribution revenue and the proposed variable distribution charge.

1 Table 7 – Proposed Fixed and Variable Distribution Charge

Customer Class Name	Fixed Component			Variable Component			Calculated *	Allocated **	Difference
	Rate ¹	Volume ²	Revenue ³	Rate ¹	Volume ²	Revenue ³			
Residential	\$12.84	\$226,500.00	\$2,908,260.00	\$0.0161	\$197,649,413.00	\$3,182,156.00	\$6,090,416	\$6,088,311	\$2,104
General Service Less Than 50 kW	\$24.05	\$28,380.00	\$682,539.00	\$0.0106	\$70,476,543.00	\$747,051.00	1,429,590	1,431,632	-2,042
General Service 50 to 4,999 kW	\$239.89	\$3,024.00	\$725,427.00	\$3.2034	\$448,543.00	\$1,436,863.00	2,162,290	2,162,305	-15
Unmetered Scattered Load	\$11.19	828	9,265	\$0.0475	501,647	23,828	33,094	33,116	-22
Sentinel Lighting	\$3.92	72	282	\$20.2204	17	344	626	626	0
Street Lighting	\$4.28	72,924	312,115	\$3.6270	11,037	40,031	352,146	352,489	-343
TOTAL		331,728	\$4,637,889		269,087,200	\$5,430,273	\$10,068,161	\$10,068,480	-\$318

2 ¹ Proposed rates, rounded off to decimals displayed

3 ² Fixed Charge = # Customers (Connections) multiplied by 12 (months); Variable Charge = # kW's or kWh's, as applicable

4 ³ Rate x Volume

5 * Sum of 'Revenue' columns

6 ** Gross Base Revenue Requirement

7

8

Determination of Service Revenue Requirement

WPI has determined its total 2008 base service revenue requirement to be \$9,934,837. The total revenue offset in the amount of \$669,555 reduces WPI's total service revenue requirement to a base revenue requirement to \$9,265,283, which is used to determine the proposed distribution rates. The base revenue requirement is derived from WPI's 2009 capital and operating forecasts, weather normalized usage, forecasted customer counts, and WPI's regulated return on rate base. The base revenue requirement is further adjusted by a total of \$803,197 for the Transformer Allowance and the Low Voltage costs from Hydro One Networks Inc. The base revenue requirement is summarized in the below.

Calculation of Base Revenue Requirement

Description	Amount
OM&A Expenses	4,868,425
Amortization Expense	1,829,713
Total Distribution Expenses	6,698,138
Regulated Return On Capital	2,339,543
PILs (with gross-up)	897,156
Service Revenue Requirement	9,934,837
Less: Revenue Offsets	669,555
Base Revenue Requirement	9,265,283
Transformer Allowance	69,720
Low Voltage - from Hydro One	733,477
Adjusted Base Revenue Requirement	10,068,480

Reconciliation of Rate Class Revenue to total Revenue Requirement

Customer Class Name	Fixed Distribution Revenue	Variable Distribution Revenue	Transformer Allowance	Low Voltage Charges	Calculated	Allocated	Difference*
Residential	\$2,908,260	\$2,830,908		\$351,248	\$6,090,416	\$6,088,311	\$2,104
General Service Less Than 50 kW	\$682,539	635,721		111,330	1,429,590	1,431,632	-2,042
General Service 50 to 4,999 kW	\$725,427	1,102,085	69,720	265,058	2,162,290	2,162,305	-15
Unmetered Scattered Load	\$9,265	23,036		792	33,094	33,116	-22
Sentinel Lighting	\$282	336		8	626	626	0
Street Lighting	\$312,115	34,990		5,041	352,146	352,489	-343
TOTAL	\$4,637,889	\$4,627,076	\$69,720	\$733,477	\$10,068,161	\$10,068,480	-\$318

* Difference due to rounding

Calculation of Difference between Revenue and Allocated Cost under Current and Proposed Rates

The table below calculates the difference between WPI's Revenue and Allocated Costs under WPI's current rate structure:

Customer Class Name	Current Rate Structure			
	Allocated Revenue	Allocated Cost	Allocation of Class	Difference
Residential	\$5,737,242	\$6,043,739	61.92%	-\$306,497
General Service Less Than 50 kW	\$1,320,746	\$1,626,579	14.25%	-\$305,833
General Service 50 to 4,999 kW	\$1,960,311	\$1,099,079	21.16%	\$861,232
Unmetered Scattered Load	\$30,064	\$32,323	0.32%	-\$2,259
Sentinel Lighting	\$246	\$618	0.00%	-\$372
Street Lighting	\$216,674	\$462,945	2.34%	-\$246,271
TOTAL	\$9,265,283	\$9,265,283	100.00%	\$0

The table below calculates the difference between WPI's Revenue and Allocated Costs under WPI's proposed rate structure:

Customer Class Name	Proposed Rate Structure			
	Allocated Revenue	Allocated Cost	Allocation of Class	Difference
Residential	\$5,737,063	\$6,043,739	61.92%	(\$306,676)
General Service Less Than 50 kW	\$1,320,303	\$1,626,579	14.25%	(\$306,276)
General Service 50 to 4,999 kW	\$1,827,527	\$1,099,079	19.72%	\$728,448
Unmetered Scattered Load	\$32,323	\$32,323	0.35%	\$0
Sentinel Lighting	\$618	\$618	0.01%	\$0
Street Lighting	\$347,448	\$462,945	3.75%	(\$115,497)
TOTAL	\$9,265,283	\$9,265,283	100.00%	\$0

Revenue/Cost Ratios

The existing and proposed revenue/cost ratios are as follows:

Customer Class Name	Rate Application (2009 Test Year)			Cost Allocation	Target Range		
	Allocated Revenues	Allocated Costs	Revenue to Cost Ratio		Variance	Floor	Ceiling
Residential	5,737,063	6,043,739	94.93%	94.75%	0.18%	85.00%	115.00%
General Service Less Than 50 kW	1,320,303	1,626,579	81.17%	80.77%	0.40%	80.00%	120.00%
General Service 50 to 4,999 kW	1,827,527	1,099,079	166.28%	168.03%	-1.75%	80.00%	180.00%
Unmetered Scattered Load	32,323	32,323	100.00%	100.39%	-0.39%	80.00%	120.00%
Sentinel Lighting	618	618	100.00%	99.35%	0.65%	70.00%	120.00%
Street Lighting	347,448	462,945	75.05%	50.04%	25.01%	70.00%	120.00%
TOTAL	9,265,283	9,265,283					

Rate Mitigation

WPI considers the proposed rate adjustments not to be of such impact to the customer that it requires rate mitigation.

Existing Rate Classes

Residential

This classification refers to customers residing in residential dwelling units taking energy at 600 volts or less, with energy generally supplied as single phase, 3-wire, 60 Hertz, having a nominal voltage of 120/240 volts.

General Service Less than 50 kW

This classification refers to general service buildings, defined as buildings that are used for purposes other than single-family dwellings, taking energy at 600 volts or less, requiring a connection with a connected load of less than 50 kW, and including Town Houses and Condominiums that require centralized bulk metering, 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 refers to general service buildings, defined as buildings that are used for purposes other than single-family dwellings, requiring a connection with a connected load greater than 50 kW but less than 5,000 kW, 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.

General Service 50 to 4,999 kW – Time of Use

This classification refers to general service buildings, defined as buildings that are used for purposes other than single-family dwellings, requiring a connection with a connected load greater than 50 kW but less than 5,000 kW on time of use rates, 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.

Unmetered Scattered Load

This classification refers to an account taking electricity at 600 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, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load.

Sentinel Lighting

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light.

Street Lighting

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photocells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

Existing Rate Schedule

**EB – 2007 – 0865
Monthly Rates and Charges**

Residential

Service Charge	\$	10.88
Distribution Volumetric Rate	\$/kWh	0.0133
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0044
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0054
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

General Service Less Than 50 kW

Service Charge	\$	19.74
Distribution Volumetric Rate	\$/kWh	0.0086
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0048
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

General Service 50 to 4,999 kW

Service Charge	\$	240.40
Distribution Volumetric Rate	\$/kW	2.2180
Retail Transmission Rate – Network Service Rate	\$/kW	1.6425
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.9371
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

General Service 50 to 4,999 kW – Time of Use

Service Charge	\$	43.98
Distribution Volumetric Rate	\$/kW	0.3328
Retail Transmission Rate – Network Service Rate	\$/kW	1.7431
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	2.1233
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Unmetered Scattered Load

Service Charge (per customer)	\$	4.40
Distribution Volumetric Rate	\$/kWh	0.0453
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0048
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Sentinel Lighting

Service Charge (per connection)	\$	1.35
Distribution Volumetric Rate	\$/kW	6.9702
Retail Transmission Rate – Network Service Rate	\$/kW	1.2450
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.5286
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Street Lighting

Service Charge (per connection)	\$	2.31
Distribution Volumetric Rate	\$/kW	1.9673
Retail Transmission Rate – Network Service Rate	\$/kW	1.2388
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.4973
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	\$	15.00
Statement of Account	\$	15.00
Pulling post dated cheques	\$	15.00
Duplicate invoices for previous billing	\$	15.00
Request for other billing information	\$	15.00
Easement letter	\$	15.00
Income tax letter	\$	15.00
Notification charge	\$	15.00
Account history	\$	15.00
Credit reference/credit check (plus credit agency costs)	\$	15.00
Returned cheque charge (plus bank charges)	\$	15.00
Charge to certify cheques	\$	15.00
Legal letter charge	\$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	\$	30.00
Special meter reads	\$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	\$	30.00

1	Non-Payment of Account		
2	Late Payment - per month	%	1.50
3	Late Payment - per annum	%	19.56
4	Collection of account charge – no disconnect	\$	30.00
5	Collection of account charge – no disconnect – after regular hours	\$	165.00
6	Disconnect/Reconnect Charges at meter – during regular hours	\$	65.00
7	Disconnect/Reconnect Charges at meter – after regular hours	\$	185.00
8	Disconnect/Reconnect at pole – during regular hours	\$	185.00
9	Disconnect/Reconnect at pole – after regular hours	\$	415.00
10			
11	Install/Remove load control device – during regular hours	\$	65.00
12	Install/Remove load control device – after regular hours	\$	185.00
13	Service call – customer owned equipment	\$	30.00
14	Service call – after regular hours	\$	165.00
15	Temporary service installation and removal – overhead – no transformer	\$	500.00
16	Temporary service installation and removal – underground – no transformer	\$	300.00
17	Temporary service installation and removal – overhead – with transformer	\$	1,000.00
18	Specific charge for access to power poles \$/pole/year	\$	22.35
19			
20	Allowances		
21	Transformer Allowance for Ownership - per kW of billing demand/month	\$/kW	(0.60)
22	Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

LOSS FACTORS

26	Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0637
27	Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
28	Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0530
29	Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Proposed Rate Classes

WPI does not propose to change its existing rate classes; with the exception of the General Service 50 – 4,999 kW – TOU rate classification. WPI is proposing to delete the General Service 50 – 4,999 kW - TOU rate classification. This specific rate class has only one customer, and under Run 1 of the cost allocation model, this rate classification had a revenue/cost ratio of 11.08%. This rate classification was included with General Service 50 – 4,999 kW for Run 2 of the cost allocation to produce the results that have been identified in Exhibit 8.

This bill impact of reclassifying the General Service 50 – 4,999 kW – TOU to a General Service 50 - 4,999 kW customer is as follows:

	Metric	2008 Bill			2009 Bill			Change \$	Impact %
		Volume	Rate	Charge	Volume	Rate	Charge		
Monthly Service Charge				\$43.94			\$240.89	196.95	448.22%
Distribution	kW	450	\$0.33	\$149.58	450	\$3.20	\$1,441.53	1,291.95	863.72%
Sub-Total (Distribution)				\$193.52			\$1,682.42	1,488.90	769.38%
Deferral/Variance Disposition	kW	450	\$0.00	\$0.00	450	\$0.41	\$183.56	183.56	
Electricity (Commodity)	kWh	159,555		\$9,407.00	161,820		\$9,540.63	133.64	1.42%
Transmission - Network	kW	450	\$1.64	\$739.13	450	\$1.64	\$739.13	0	0.00%
Transmission - Connection	kW	450	\$1.94	\$871.70	450	\$1.94	\$871.70	0	0.00%
Wholesale Market Service	kWh	159,555	\$0.01	\$829.69	161,820	\$0.01	\$841.46	11.78	1.42%
Rural Rate Protection	kWh	159,555	\$0.00	\$159.56	161,820	\$0.00	\$161.82	2.26	1.42%
Debt Retirement Charge	kWh	150,000	\$0.00	\$105.00	150,000	\$0.00	\$105.00	0	0.00%
Total Bill				\$12,305.58			\$14,125.71	\$1,820.13	14.79%

The proposed deletion of the General Service 50 – 4,999 kW – TOU rate category reflects the Board's recommendation to delete TOU rate categories. The Applicant considers the rate impact of the proposed change to be acceptable given that the rate is consistent with that charged similar customers. Consequently, WPI does not consider it appropriate to implement rate mitigation for the affected customers.

Proposed Rate Schedule

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The following attachment is the Proposed Rate Schedule.

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Appendix 1-1

		Effective May 1/09
Residential		
Service Charge	\$	13.84
Distribution Volumetric Rate	\$/kWh	0.0161
Regulatory Asset Recovery	\$/kWh	0.0015
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0044
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0054
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25
General Service Less Than 50 kW		
Service Charge	\$	25.05
Distribution Volumetric Rate	\$/kWh	0.0106
Regulatory Asset Recovery	\$/kWh	0.0012
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0048
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25
General Service 50 to 4,999 kW		
Service Charge	\$	240.89
Distribution Volumetric Rate	\$/kW	3.2034
Regulatory Asset Recovery	\$/kW	0.4079
Retail Transmission Rate – Network Service Rate	\$/kW	1.6425
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.9371
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25
Unmetered Scattered Load		
Service Charge	\$	11.19
Distribution Volumetric Rate	\$/kWh	0.0475
Regulatory Asset Recovery	\$/kWh	0.0019
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0048
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Appendix 1-1

		Effective May 1/09
Sentinel Lighting		
Service Charge (per connection)	\$	4.92
Distribution Volumetric Rate	\$/kW	20.2204
Regulatory Asset Recovery	\$/kW	0.8041
Retail Transmission Rate – Network Service Rate	\$/kW	1.2450
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.5286
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25
Street Lighting		
Service Charge (per connection)	\$	4.28
Distribution Volumetric Rate	\$/kW	3.6270
Regulatory Asset Recovery	\$/kW	0.7275
Retail Transmission Rate – Network Service Rate	\$/kW	1.2388
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.4973
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Appendix 1-1

		Effective May 1/09
Specific Service Charges		
Arrears Certificate	\$	15.00
Statement of Account	\$	15.00
Pulling post-dated cheques	\$	15.00
Duplicate invoices for previous billing	\$	15.00
Request for other billing information	\$	15.00
Easement Letter	\$	15.00
Income tax letter	\$	15.00
Notification Charge	\$	15.00
Account history	\$	15.00
Credit reference/credit check (plus credit agency costs)	\$	15.00
Returned Cheque charge (plus bank charges)	\$	15.00
Charge to certify cheque	\$	15.00
Legal letter charge	\$	15.00
Account set up charge / change of occupancy charge	\$	30.00
Special Meter reads	\$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	\$	30.00
Late Payment - per month	%	1.50
Collection of account charge – no disconnection	\$	30.00
Collection of account charge – no disconnection – after regular hours	\$	165.00
Disconnect/Reconnect at meter – during regular hours	\$	65.00
Disconnect/Reconnect at meter – after regular hours	\$	185.00
Disconnect/Reconnect at pole – during regular hours	\$	185.00
Disconnect/Reconnect at pole – after regular hours	\$	415.00
Install / remove load control device – during regular hours	\$	65.00
Install / remove load control device – after regular hours	\$	185.00
Service call – customer-owned equipment	\$	30.00
Service call – after regular hours	\$	165.00
Temporary service install and remove – overhead – no transformer	\$	500.00
Temporary service install and remove – underground – no transformer	\$	300.00
Temporary service install and remove – overhead – with transformer	\$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	\$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	\$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)
LOSS FACTORS		
Secondary Metered Customer < 5,000 kW		1.0788
Primary Metered Customer < 5,000 kW		1.0680

Rate Impacts

The following attachment is Rate Impacts model.

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Residential

Volume		RPP Rate Class	Distribution Charges		Total Bill	
kWh *	kW		\$ change	% change	\$ change	% change
1,000		Summer	\$5.77	23.9%	\$8.42	8.5%
1,000		Winter	\$5.77	23.9%	\$8.42	8.8%
1,500		Summer	\$7.17	23.3%	\$11.10	7.6%
1,500		Winter	\$7.17	23.3%	\$11.10	7.8%
2,000		Summer	\$8.57	22.9%	\$13.83	7.2%
2,000		Winter	\$8.57	22.9%	\$13.83	7.3%

* Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Residential

1,000 kWh's

RPP: Summer

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge				\$10.87			\$13.84	\$2.97	27.3%
Distribution	kWh	1,000	\$0.0133	\$13.30	1,000	\$0.0161	\$16.10	\$2.80	21.1%
Sub-Total (Distribution)				\$24.17			\$29.94	\$5.77	23.9%
Deferral/Variance	kWh	1,000			1,000	\$0.0015	\$1.50	\$1.50	
Electricity (Commodity)	kWh	1,064	RPP-Summer	\$57.36	1,079	RPP-Summer	\$58.25	\$0.89	1.6%
Transmission - Network	kWh	1,064	\$0.0044	\$4.68	1,079	\$0.0044	\$4.75	\$0.07	1.5%
Transmission - Connection	kWh	1,064	\$0.0054	\$5.74	1,079	\$0.0054	\$5.83	\$0.09	1.6%
Wholesale Market Service	kWh	1,064	\$0.0052	\$5.53	1,079	\$0.0052	\$5.61	\$0.08	1.4%
Rural Rate Protection	kWh	1,064	\$0.0010	\$1.06	1,079	\$0.0010	\$1.08	\$0.02	1.9%
Debt Retirement Charge	kWh	1,000	\$0.0007	\$0.70	1,000	\$0.0007	\$0.70		
TOTAL BILL				\$99.24			\$107.66	\$8.42	8.5%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Residential

1,000 kWh's

RPP: Winter

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge				\$10.87			\$13.84	\$2.97	27.3%
Distribution	kWh	1,000	\$0.0133	\$13.30	1,000	\$0.0161	\$16.10	\$2.80	21.1%
Sub-Total (Distribution)				\$24.17			\$29.94	\$5.77	23.9%
Deferral/Variance	kWh	1,000			1,000	\$0.0015	\$1.50	\$1.50	
Electricity (Commodity)	kWh	1,064	RPP-Winter	\$53.76	1,079	RPP-Winter	\$54.65	\$0.89	1.7%
Transmission - Network	kWh	1,064	\$0.0044	\$4.68	1,079	\$0.0044	\$4.75	\$0.07	1.5%
Transmission - Connection	kWh	1,064	\$0.0054	\$5.74	1,079	\$0.0054	\$5.83	\$0.09	1.6%
Wholesale Market Service	kWh	1,064	\$0.0052	\$5.53	1,079	\$0.0052	\$5.61	\$0.08	1.4%
Rural Rate Protection	kWh	1,064	\$0.0010	\$1.06	1,079	\$0.0010	\$1.08	\$0.02	1.9%
Debt Retirement Charge	kWh	1,000	\$0.0007	\$0.70	1,000	\$0.0007	\$0.70		
TOTAL BILL				\$95.64			\$104.06	\$8.42	8.8%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Residential

1,500 kWh's

RPP: Summer

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge				\$10.87			\$13.84	\$2.97	27.3%
Distribution	kWh	1,500	\$0.0133	\$19.95	1,500	\$0.0161	\$24.15	\$4.20	21.1%
Sub-Total (Distribution)				\$30.82			\$37.99	\$7.17	23.3%
Deferral/Variance	kWh	1,500			1,500	\$0.0015	\$2.25	\$2.25	
Electricity (Commodity)	kWh	1,596	RPP-Summer	\$88.74	1,618	RPP-Summer	\$90.07	\$1.33	1.5%
Transmission - Network	kWh	1,596	\$0.0044	\$7.02	1,618	\$0.0044	\$7.12	\$0.10	1.4%
Transmission - Connection	kWh	1,596	\$0.0054	\$8.62	1,618	\$0.0054	\$8.74	\$0.12	1.4%
Wholesale Market Service	kWh	1,596	\$0.0052	\$8.30	1,618	\$0.0052	\$8.41	\$0.11	1.3%
Rural Rate Protection	kWh	1,596	\$0.0010	\$1.60	1,618	\$0.0010	\$1.62	\$0.02	1.3%
Debt Retirement Charge	kWh	1,500	\$0.0007	\$1.05	1,500	\$0.0007	\$1.05		
TOTAL BILL				\$146.15			\$157.25	\$11.10	7.6%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Residential

1,500 kWh's

RPP: Winter

Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
	Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge			\$10.87			\$13.84	\$2.97	27.3%
Distribution	1,500	\$0.0133	\$19.95	1,500	\$0.0161	\$24.15	\$4.20	21.1%
Sub-Total (Distribution)			\$30.82			\$37.99	\$7.17	23.3%
Deferral/Variance	1,500			1,500	\$0.0015	\$2.25	\$2.25	
Electricity (Commodity)	1,596	RPP-Winter	\$85.14	1,618	RPP-Winter	\$86.47	\$1.33	1.6%
Transmission - Network	1,596	\$0.0044	\$7.02	1,618	\$0.0044	\$7.12	\$0.10	1.4%
Transmission - Connection	1,596	\$0.0054	\$8.62	1,618	\$0.0054	\$8.74	\$0.12	1.4%
Wholesale Market Service	1,596	\$0.0052	\$8.30	1,618	\$0.0052	\$8.41	\$0.11	1.3%
Rural Rate Protection	1,596	\$0.0010	\$1.60	1,618	\$0.0010	\$1.62	\$0.02	1.3%
Debt Retirement Charge	1,500	\$0.0007	\$1.05	1,500	\$0.0007	\$1.05		
TOTAL BILL			\$142.55			\$153.65	\$11.10	7.8%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Residential

2,000 kWh's

RPP: Summer

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge				\$10.87			\$13.84	\$2.97	27.3%
Distribution	kWh	2,000	\$0.0133	\$26.60	2,000	\$0.0161	\$32.20	\$5.60	21.1%
Sub-Total (Distribution)				\$37.47			\$46.04	\$8.57	22.9%
Deferral/Variance	kWh	2,000			2,000	\$0.0015	\$3.00	\$3.00	
Electricity (Commodity)	kWh	2,127	RPP-Summer	\$120.12	2,158	RPP-Summer	\$121.90	\$1.78	1.5%
Transmission - Network	kWh	2,127	\$0.0044	\$9.36	2,158	\$0.0044	\$9.49	\$0.13	1.4%
Transmission - Connection	kWh	2,127	\$0.0054	\$11.49	2,158	\$0.0054	\$11.65	\$0.16	1.4%
Wholesale Market Service	kWh	2,127	\$0.0052	\$11.06	2,158	\$0.0052	\$11.22	\$0.16	1.4%
Rural Rate Protection	kWh	2,127	\$0.0010	\$2.13	2,158	\$0.0010	\$2.16	\$0.03	1.4%
Debt Retirement Charge	kWh	2,000	\$0.0007	\$1.40	2,000	\$0.0007	\$1.40		
TOTAL BILL				\$193.03			\$206.86	\$13.83	7.2%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Residential

2,000 kWh's

RPP: Winter

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge				\$10.87			\$13.84	\$2.97	27.3%
Distribution	kWh	2,000	\$0.0133	\$26.60	2,000	\$0.0161	\$32.20	\$5.60	21.1%
Sub-Total (Distribution)				\$37.47			\$46.04	\$8.57	22.9%
Deferral/Variance	kWh	2,000			2,000	\$0.0015	\$3.00	\$3.00	
Electricity (Commodity)	kWh	2,127	RPP-Winter	\$116.52	2,158	RPP-Winter	\$118.30	\$1.78	1.5%
Transmission - Network	kWh	2,127	\$0.0044	\$9.36	2,158	\$0.0044	\$9.49	\$0.13	1.4%
Transmission - Connection	kWh	2,127	\$0.0054	\$11.49	2,158	\$0.0054	\$11.65	\$0.16	1.4%
Wholesale Market Service	kWh	2,127	\$0.0052	\$11.06	2,158	\$0.0052	\$11.22	\$0.16	1.4%
Rural Rate Protection	kWh	2,127	\$0.0010	\$2.13	2,158	\$0.0010	\$2.16	\$0.03	1.4%
Debt Retirement Charge	kWh	2,000	\$0.0007	\$1.40	2,000	\$0.0007	\$1.40		
TOTAL BILL				\$189.43			\$203.26	\$13.83	7.3%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Residential

RPP:

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge									
Distribution	kWh		\$0.0133			\$0.0161			
Sub-Total (Distribution)									
Deferral/Variance	kWh					\$0.0015			
Electricity (Commodity)	kWh		RPP-	--		RPP-	--	--	--
Transmission - Network	kWh		\$0.0044			\$0.0044			
Transmission - Connection	kWh		\$0.0054			\$0.0054			
Wholesale Market Service	kWh		\$0.0052			\$0.0052			
Rural Rate Protection	kWh		\$0.0010			\$0.0010			
Debt Retirement Charge	kWh		\$0.0007			\$0.0007			
TOTAL BILL				--			--	--	--

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service Less

Volume		RPP?	Distribution Charges		Total Bill	
kWh *	kW		\$ change	% change	\$ change	% change
2,000		Non-res.	\$9.33	25.3%	\$13.97	7.4%
2,500		Non-res.	\$10.33	25.1%	\$16.12	6.9%
4,000		Non-res.	\$13.33	24.6%	\$22.62	6.2%
5,000		Non-res.	\$15.33	24.4%	\$26.92	5.9%
10,000		Non-res.	\$25.33	24.0%	\$48.50	5.4%
12,500		Non-res.	\$30.33	23.8%	\$59.30	5.3%
15,000		Non-res.	\$35.33	23.8%	\$70.09	5.3%

* Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service Less Than 50 kW

2,000 kWh's

RPP: Non-res.

Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
	Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge			\$19.72			\$25.05	\$5.33	27.0%
Distribution	2,000	\$0.0086	\$17.20	2,000	\$0.0106	\$21.20	\$4.00	23.3%
Sub-Total (Distribution)			\$36.92			\$46.25	\$9.33	25.3%
Deferral/Variance	2,000			2,000	\$0.0012	\$2.40	\$2.40	
Electricity (Commodity)	2,127	RPP-Non-res.	\$118.77	2,158	RPP-Non-res.	\$120.55	\$1.78	1.5%
Transmission - Network	2,127	\$0.0040	\$8.51	2,158	\$0.0040	\$8.63	\$0.12	1.4%
Transmission - Connection	2,127	\$0.0048	\$10.21	2,158	\$0.0048	\$10.36	\$0.15	1.5%
Wholesale Market Service	2,127	\$0.0052	\$11.06	2,158	\$0.0052	\$11.22	\$0.16	1.4%
Rural Rate Protection	2,127	\$0.0010	\$2.13	2,158	\$0.0010	\$2.16	\$0.03	1.4%
Debt Retirement Charge	2,000	\$0.0007	\$1.40	2,000	\$0.0007	\$1.40		
TOTAL BILL			\$189.00			\$202.97	\$13.97	7.4%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service Less Than 50 kW

2,500 kWh's

RPP: Non-res.

Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
	Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge			\$19.72			\$25.05	\$5.33	27.0%
Distribution	2,500	\$0.0086	\$21.50	2,500	\$0.0106	\$26.50	\$5.00	23.3%
Sub-Total (Distribution)			\$41.22			\$51.55	\$10.33	25.1%
Deferral/Variance	2,500			2,500	\$0.0012	\$3.00	\$3.00	
Electricity (Commodity)	2,659	RPP-Non-res.	\$150.15	2,697	RPP-Non-res.	\$152.37	\$2.22	1.5%
Transmission - Network	2,659	\$0.0040	\$10.64	2,697	\$0.0040	\$10.79	\$0.15	1.4%
Transmission - Connection	2,659	\$0.0048	\$12.76	2,697	\$0.0048	\$12.95	\$0.19	1.5%
Wholesale Market Service	2,659	\$0.0052	\$13.83	2,697	\$0.0052	\$14.02	\$0.19	1.4%
Rural Rate Protection	2,659	\$0.0010	\$2.66	2,697	\$0.0010	\$2.70	\$0.04	1.5%
Debt Retirement Charge	2,500	\$0.0007	\$1.75	2,500	\$0.0007	\$1.75		
TOTAL BILL			\$233.01			\$249.13	\$16.12	6.9%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service Less Than 50 kW

4,000 kWh's

RPP: Non-res.

Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
	Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge			\$19.72			\$25.05	\$5.33	27.0%
Distribution	4,000	\$0.0086	\$34.40	4,000	\$0.0106	\$42.40	\$8.00	23.3%
Sub-Total (Distribution)			\$54.12			\$67.45	\$13.33	24.6%
Deferral/Variance	4,000			4,000	\$0.0012	\$4.80	\$4.80	
Electricity (Commodity)	4,255	RPP-Non-res.	\$244.28	4,315	RPP-Non-res.	\$247.85	\$3.57	1.5%
Transmission - Network	4,255	\$0.0040	\$17.02	4,315	\$0.0040	\$17.26	\$0.24	1.4%
Transmission - Connection	4,255	\$0.0048	\$20.42	4,315	\$0.0048	\$20.71	\$0.29	1.4%
Wholesale Market Service	4,255	\$0.0052	\$22.12	4,315	\$0.0052	\$22.44	\$0.32	1.4%
Rural Rate Protection	4,255	\$0.0010	\$4.25	4,315	\$0.0010	\$4.32	\$0.07	1.6%
Debt Retirement Charge	4,000	\$0.0007	\$2.80	4,000	\$0.0007	\$2.80		
TOTAL BILL			\$365.01			\$387.63	\$22.62	6.2%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service Less Than 50 kW

5,000 kWh's

RPP: Non-res.

Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
	Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge			\$19.72			\$25.05	\$5.33	27.0%
Distribution	5,000	\$0.0086	\$43.00	5,000	\$0.0106	\$53.00	\$10.00	23.3%
Sub-Total (Distribution)			\$62.72			\$78.05	\$15.33	24.4%
Deferral/Variance	5,000			5,000	\$0.0012	\$6.00	\$6.00	
Electricity (Commodity)	5,319	RPP-Non-res.	\$307.04	5,394	RPP-Non-res.	\$311.50	\$4.46	1.5%
Transmission - Network	5,319	\$0.0040	\$21.27	5,394	\$0.0040	\$21.58	\$0.31	1.5%
Transmission - Connection	5,319	\$0.0048	\$25.53	5,394	\$0.0048	\$25.89	\$0.36	1.4%
Wholesale Market Service	5,319	\$0.0052	\$27.66	5,394	\$0.0052	\$28.05	\$0.39	1.4%
Rural Rate Protection	5,319	\$0.0010	\$5.32	5,394	\$0.0010	\$5.39	\$0.07	1.3%
Debt Retirement Charge	5,000	\$0.0007	\$3.50	5,000	\$0.0007	\$3.50		
TOTAL BILL			\$453.04			\$479.96	\$26.92	5.9%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service Less Than 50 kW

RPP: Non-res.

10,000 kWh's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge				\$19.72			\$25.05	\$5.33	27.0%
Distribution	kWh	10,000	\$0.0086	\$86.00	10,000	\$0.0106	\$106.00	\$20.00	23.3%
Sub-Total (Distribution)				\$105.72			\$131.05	\$25.33	24.0%
Deferral/Variance	kWh	10,000			10,000	\$0.0012	\$12.00	\$12.00	
Electricity (Commodity)	kWh	10,637	RPP-Non-res.	\$620.83	10,788	RPP-Non-res.	\$629.74	\$8.91	1.4%
Transmission - Network	kWh	10,637	\$0.0040	\$42.55	10,788	\$0.0040	\$43.15	\$0.60	1.4%
Transmission - Connection	kWh	10,637	\$0.0048	\$51.06	10,788	\$0.0048	\$51.78	\$0.72	1.4%
Wholesale Market Service	kWh	10,637	\$0.0052	\$55.31	10,788	\$0.0052	\$56.10	\$0.79	1.4%
Rural Rate Protection	kWh	10,637	\$0.0010	\$10.64	10,788	\$0.0010	\$10.79	\$0.15	1.4%
Debt Retirement Charge	kWh	10,000	\$0.0007	\$7.00	10,000	\$0.0007	\$7.00		
TOTAL BILL				\$893.11			\$941.61	\$48.50	5.4%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service Less Than 50 kW

RPP: Non-res.

12,500 kWh's

Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
	Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge			\$19.72			\$25.05	\$5.33	27.0%
Distribution	12,500	\$0.0086	\$107.50	12,500	\$0.0106	\$132.50	\$25.00	23.3%
Sub-Total (Distribution)			\$127.22			\$157.55	\$30.33	23.8%
Deferral/Variance	12,500			12,500	\$0.0012	\$15.00	\$15.00	
Electricity (Commodity)	13,296	RPP-Non-res.	\$777.73	13,485	RPP-Non-res.	\$788.87	\$11.14	1.4%
Transmission - Network	13,296	\$0.0040	\$53.19	13,485	\$0.0040	\$53.94	\$0.75	1.4%
Transmission - Connection	13,296	\$0.0048	\$63.82	13,485	\$0.0048	\$64.73	\$0.91	1.4%
Wholesale Market Service	13,296	\$0.0052	\$69.14	13,485	\$0.0052	\$70.12	\$0.98	1.4%
Rural Rate Protection	13,296	\$0.0010	\$13.30	13,485	\$0.0010	\$13.49	\$0.19	1.4%
Debt Retirement Charge	12,500	\$0.0007	\$8.75	12,500	\$0.0007	\$8.75		
TOTAL BILL			\$1,113.15			\$1,172.45	\$59.30	5.3%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service Less Than 50 kW

RPP: Non-res.

15,000 kWh's

Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
	Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge			\$19.72			\$25.05	\$5.33	27.0%
Distribution	15,000	\$0.0086	\$129.00	15,000	\$0.0106	\$159.00	\$30.00	23.3%
Sub-Total (Distribution)			\$148.72			\$184.05	\$35.33	23.8%
Deferral/Variance	15,000			15,000	\$0.0012	\$18.00	\$18.00	
Electricity (Commodity)	15,956	RPP-Non-res.	\$934.62	16,182	RPP-Non-res.	\$947.99	\$13.37	1.4%
Transmission - Network	15,956	\$0.0040	\$63.82	16,182	\$0.0040	\$64.73	\$0.91	1.4%
Transmission - Connection	15,956	\$0.0048	\$76.59	16,182	\$0.0048	\$77.67	\$1.08	1.4%
Wholesale Market Service	15,956	\$0.0052	\$82.97	16,182	\$0.0052	\$84.15	\$1.18	1.4%
Rural Rate Protection	15,956	\$0.0010	\$15.96	16,182	\$0.0010	\$16.18	\$0.22	1.4%
Debt Retirement Charge	15,000	\$0.0007	\$10.50	15,000	\$0.0007	\$10.50		
TOTAL BILL			\$1,333.18			\$1,403.27	\$70.09	5.3%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service 50 to

Volume		RPP?	Distribution Charges		Total Bill	
kWh *	kW		\$ change	% change	\$ change	% change
22,000	50	Non-res.	\$50.12	14.3%	\$92.17	4.5%
35,000	75	Non-res.	\$74.81	18.4%	\$139.86	4.5%
50,000	100	Non-res.	\$99.50	21.5%	\$189.51	4.4%
125,000	250	Non-res.	\$247.64	31.2%	\$472.68	4.5%
250,000	500	n/a	\$494.54	36.7%	\$927.63	4.8%
400,000	750	n/a	\$741.44	39.0%	\$1,413.99	4.6%
750,000	1,500	n/a	\$1,482.14	41.6%	\$2,781.41	4.8%

* Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service 50 to 4,999 kW

RPP: Non-res.

22,000 kWh's 50 kW's	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge				\$240.15			\$240.89	\$0.74	0.3%
Distribution	kW	50	\$2.2158	\$110.79	50	\$3.2034	\$160.17	\$49.38	44.6%
Sub-Total (Distribution)				\$350.94			\$401.06	\$50.12	14.3%
Deferral/Variance	kW	50			50	\$0.4079	\$20.40	\$20.40	
Electricity (Commodity)	kWh	23,401	RPP-Non-res.	\$1,373.93	23,734	RPP-Non-res.	\$1,393.53	\$19.60	1.4%
Transmission - Network	kW	50	\$1.6425	\$82.13	50	\$1.6425	\$82.13		
Transmission - Connection	kW	50	\$1.9371	\$96.86	50	\$1.9371	\$96.86		
Wholesale Market Service	kWh	23,401	\$0.0052	\$121.69	23,734	\$0.0052	\$123.41	\$1.72	1.4%
Rural Rate Protection	kWh	23,401	\$0.0010	\$23.40	23,734	\$0.0010	\$23.73	\$0.33	1.4%
Debt Retirement Charge	kWh	22,000	\$0.0007	\$15.40	22,000	\$0.0007	\$15.40		
TOTAL BILL				\$2,064.35			\$2,156.52	\$92.17	4.5%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service 50 to 4,999 kW

RPP: Non-res.

35,000 kWh's 75 kW's	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				\$240.15			\$240.89	\$0.74	0.3%
Distribution	kW	75	\$2.2158	\$166.19	75	\$3.2034	\$240.26	\$74.07	44.6%
Sub-Total (Distribution)				\$406.34			\$481.15	\$74.81	18.4%
Deferral/Variance	kW	75			75	\$0.4079	\$30.59	\$30.59	
Electricity (Commodity)	kWh	37,230	RPP-Non-res.	\$2,189.79	37,758	RPP-Non-res.	\$2,220.97	\$31.18	1.4%
Transmission - Network	kW	75	\$1.6425	\$123.19	75	\$1.6425	\$123.19		
Transmission - Connection	kW	75	\$1.9371	\$145.28	75	\$1.9371	\$145.28		
Wholesale Market Service	kWh	37,230	\$0.0052	\$193.59	37,758	\$0.0052	\$196.34	\$2.75	1.4%
Rural Rate Protection	kWh	37,230	\$0.0010	\$37.23	37,758	\$0.0010	\$37.76	\$0.53	1.4%
Debt Retirement Charge	kWh	35,000	\$0.0007	\$24.50	35,000	\$0.0007	\$24.50		
TOTAL BILL				\$3,119.92			\$3,259.78	\$139.86	4.5%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service 50 to 4,999 kW

RPP: Non-res.

50,000 kWh's 100 kW's	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				\$240.15			\$240.89	\$0.74	0.3%
Distribution	kW	100	\$2.2158	\$221.58	100	\$3.2034	\$320.34	\$98.76	44.6%
Sub-Total (Distribution)				\$461.73			\$561.23	\$99.50	21.5%
Deferral/Variance	kW	100			100	\$0.4079	\$40.79	\$40.79	
Electricity (Commodity)	kWh	53,185	RPP-Non-res.	\$3,131.17	53,940	RPP-Non-res.	\$3,175.71	\$44.54	1.4%
Transmission - Network	kW	100	\$1.6425	\$164.25	100	\$1.6425	\$164.25		
Transmission - Connection	kW	100	\$1.9371	\$193.71	100	\$1.9371	\$193.71		
Wholesale Market Service	kWh	53,185	\$0.0052	\$276.56	53,940	\$0.0052	\$280.49	\$3.93	1.4%
Rural Rate Protection	kWh	53,185	\$0.0010	\$53.19	53,940	\$0.0010	\$53.94	\$0.75	1.4%
Debt Retirement Charge	kWh	50,000	\$0.0007	\$35.00	50,000	\$0.0007	\$35.00		
TOTAL BILL				\$4,315.61			\$4,505.12	\$189.51	4.4%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service 50 to 4,999 kW

RPP: Non-res.

Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
	Volume	Rate	Charge	Volume	Rate	Charge		%
125,000 kWh's								
250 kW's								
Monthly Service Charge			\$240.15			\$240.89	\$0.74	0.3%
Distribution	250	\$2.2158	\$553.95	250	\$3.2034	\$800.85	\$246.90	44.6%
Sub-Total (Distribution)			\$794.10			\$1,041.74	\$247.64	31.2%
Deferral/Variance	250			250	\$0.4079	\$101.98	\$101.98	
Electricity (Commodity)	132,963	RPP-Non-res.	\$7,838.04	134,850	RPP-Non-res.	\$7,949.40	\$111.36	1.4%
Transmission - Network	250	\$1.6425	\$410.63	250	\$1.6425	\$410.63		
Transmission - Connection	250	\$1.9371	\$484.28	250	\$1.9371	\$484.28		
Wholesale Market Service	132,963	\$0.0052	\$691.41	134,850	\$0.0052	\$701.22	\$9.81	1.4%
Rural Rate Protection	132,963	\$0.0010	\$132.96	134,850	\$0.0010	\$134.85	\$1.89	1.4%
Debt Retirement Charge	125,000	\$0.0007	\$87.50	125,000	\$0.0007	\$87.50		
TOTAL BILL			\$10,438.92			\$10,911.60	\$472.68	4.5%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service 50 to 4,999 kW

RPP: n/a

250,000 kWh's 500 kW's	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				\$240.15			\$240.89	\$0.74	0.3%
Distribution	kW	500	\$2.2158	\$1,107.90	500	\$3.2034	\$1,601.70	\$493.80	44.6%
Sub-Total (Distribution)				\$1,348.05			\$1,842.59	\$494.54	36.7%
Deferral/Variance	kW	500			500	\$0.4079	\$203.95	\$203.95	
Electricity (Commodity)	kWh	265,925	\$0.0545	\$14,492.91	269,700	\$0.0545	\$14,698.65	\$205.74	1.4%
Transmission - Network	kW	500	\$1.6425	\$821.25	500	\$1.6425	\$821.25		
Transmission - Connection	kW	500	\$1.9371	\$968.55	500	\$1.9371	\$968.55		
Wholesale Market Service	kWh	265,925	\$0.0052	\$1,382.81	269,700	\$0.0052	\$1,402.44	\$19.63	1.4%
Rural Rate Protection	kWh	265,925	\$0.0010	\$265.93	269,700	\$0.0010	\$269.70	\$3.77	1.4%
Debt Retirement Charge	kWh	250,000	\$0.0007	\$175.00	250,000	\$0.0007	\$175.00		
TOTAL BILL				\$19,454.50			\$20,382.13	\$927.63	4.8%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service 50 to 4,999 kW

RPP: n/a

400,000 kWh's 750 kW's	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				\$240.15			\$240.89	\$0.74	0.3%
Distribution	kW	750	\$2.2158	\$1,661.85	750	\$3.2034	\$2,402.55	\$740.70	44.6%
Sub-Total (Distribution)				\$1,902.00			\$2,643.44	\$741.44	39.0%
Deferral/Variance	kW	750			750	\$0.4079	\$305.93	\$305.93	
Electricity (Commodity)	kWh	425,480	\$0.0545	\$23,188.66	431,520	\$0.0545	\$23,517.84	\$329.18	1.4%
Transmission - Network	kW	750	\$1.6425	\$1,231.88	750	\$1.6425	\$1,231.88		
Transmission - Connection	kW	750	\$1.9371	\$1,452.83	750	\$1.9371	\$1,452.83		
Wholesale Market Service	kWh	425,480	\$0.0052	\$2,212.50	431,520	\$0.0052	\$2,243.90	\$31.40	1.4%
Rural Rate Protection	kWh	425,480	\$0.0010	\$425.48	431,520	\$0.0010	\$431.52	\$6.04	1.4%
Debt Retirement Charge	kWh	400,000	\$0.0007	\$280.00	400,000	\$0.0007	\$280.00		
TOTAL BILL				\$30,693.35			\$32,107.34	\$1,413.99	4.6%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service 50 to 4,999 kW

RPP: n/a

750,000 kWh's 1,500 kW's	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				\$240.15			\$240.89	\$0.74	0.3%
Distribution	kW	1,500	\$2.2158	\$3,323.70	1,500	\$3.2034	\$4,805.10	\$1,481.40	44.6%
Sub-Total (Distribution)				\$3,563.85			\$5,045.99	\$1,482.14	41.6%
Deferral/Variance	kW	1,500			1,500	\$0.4079	\$611.85	\$611.85	
Electricity (Commodity)	kWh	797,775	\$0.0545	\$43,478.74	809,100	\$0.0545	\$44,095.95	\$617.21	1.4%
Transmission - Network	kW	1,500	\$1.6425	\$2,463.75	1,500	\$1.6425	\$2,463.75		
Transmission - Connection	kW	1,500	\$1.9371	\$2,905.65	1,500	\$1.9371	\$2,905.65		
Wholesale Market Service	kWh	797,775	\$0.0052	\$4,148.43	809,100	\$0.0052	\$4,207.32	\$58.89	1.4%
Rural Rate Protection	kWh	797,775	\$0.0010	\$797.78	809,100	\$0.0010	\$809.10	\$11.32	1.4%
Debt Retirement Charge	kWh	750,000	\$0.0007	\$525.00	750,000	\$0.0007	\$525.00		
TOTAL BILL				\$57,883.20			\$60,664.61	\$2,781.41	4.8%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Unmetered Scattered

Volume		RPP?	Distribution Charges		Total Bill	
kWh *	kW		\$ change	% change	\$ change	% change
350		Non-res.	\$7.56	37.3%	\$8.57	19.2%
500		Non-res.	\$7.89	29.2%	\$9.33	15.1%
750		Non-res.	\$8.44	22.0%	\$10.71	11.7%
1,000		Non-res.	\$8.99	18.1%	\$12.02	9.8%
1,250		Non-res.	\$9.54	15.6%	\$13.31	8.7%
1,500		Non-res.	\$10.09	13.9%	\$14.60	7.9%
2,000		Non-res.	\$11.19	11.8%	\$17.23	7.0%

* Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Unmetered Scattered Load

350 kWh's

RPP: Non-res.

Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
	Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge			\$4.40			\$11.19	\$6.79	>100%
Distribution	350	\$0.0453	\$15.86	350	\$0.0475	\$16.63	\$0.77	4.9%
Sub-Total (Distribution)			\$20.26			\$27.82	\$7.56	37.3%
Deferral/Variance	350			350	\$0.0019	\$0.67	\$0.67	
Electricity (Commodity)	372	RPP-Non-res.	\$18.61	378	RPP-Non-res.	\$18.88	\$0.27	1.5%
Transmission - Network	372	\$0.0040	\$1.49	378	\$0.0040	\$1.51	\$0.02	1.3%
Transmission - Connection	372	\$0.0048	\$1.79	378	\$0.0048	\$1.81	\$0.02	1.1%
Wholesale Market Service	372	\$0.0052	\$1.94	378	\$0.0052	\$1.96	\$0.02	1.0%
Rural Rate Protection	372	\$0.0010	\$0.37	378	\$0.0010	\$0.38	\$0.01	2.7%
Debt Retirement Charge	350	\$0.0007	\$0.25	350	\$0.0007	\$0.25		
TOTAL BILL			\$44.71			\$53.28	\$8.57	19.2%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Unmetered Scattered Load

500 kWh's

RPP: Non-res.

Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
	Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge			\$4.40			\$11.19	\$6.79	>100%
Distribution	500	\$0.0453	\$22.65	500	\$0.0475	\$23.75	\$1.10	4.9%
Sub-Total (Distribution)			\$27.05			\$34.94	\$7.89	29.2%
Deferral/Variance	500			500	\$0.0019	\$0.95	\$0.95	
Electricity (Commodity)	532	RPP-Non-res.	\$26.59	539	RPP-Non-res.	\$26.97	\$0.38	1.4%
Transmission - Network	532	\$0.0040	\$2.13	539	\$0.0040	\$2.16	\$0.03	1.4%
Transmission - Connection	532	\$0.0048	\$2.55	539	\$0.0048	\$2.59	\$0.04	1.6%
Wholesale Market Service	532	\$0.0052	\$2.77	539	\$0.0052	\$2.80	\$0.03	1.1%
Rural Rate Protection	532	\$0.0010	\$0.53	539	\$0.0010	\$0.54	\$0.01	1.9%
Debt Retirement Charge	500	\$0.0007	\$0.35	500	\$0.0007	\$0.35		
TOTAL BILL			\$61.97			\$71.30	\$9.33	15.1%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Unmetered Scattered Load

750 kWh's

RPP: Non-res.

Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
	Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge			\$4.40			\$11.19	\$6.79	>100%
Distribution	750	\$0.0453	\$33.98	750	\$0.0475	\$35.63	\$1.65	4.9%
Sub-Total (Distribution)			\$38.38			\$46.82	\$8.44	22.0%
Deferral/Variance	750			750	\$0.0019	\$1.43	\$1.43	
Electricity (Commodity)	798	RPP-Non-res.	\$40.32	809	RPP-Non-res.	\$40.99	\$0.67	1.7%
Transmission - Network	798	\$0.0040	\$3.19	809	\$0.0040	\$3.24	\$0.05	1.6%
Transmission - Connection	798	\$0.0048	\$3.83	809	\$0.0048	\$3.88	\$0.05	1.3%
Wholesale Market Service	798	\$0.0052	\$4.15	809	\$0.0052	\$4.21	\$0.06	1.4%
Rural Rate Protection	798	\$0.0010	\$0.80	809	\$0.0010	\$0.81	\$0.01	1.3%
Debt Retirement Charge	750	\$0.0007	\$0.53	750	\$0.0007	\$0.53		
TOTAL BILL			\$91.20			\$101.91	\$10.71	11.7%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Unmetered Scattered Load

1,000 kWh's

RPP: Non-res.

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge				\$4.40			\$11.19	\$6.79	>100%
Distribution	kWh	1,000	\$0.0453	\$45.30	1,000	\$0.0475	\$47.50	\$2.20	4.9%
Sub-Total (Distribution)				\$49.70			\$58.69	\$8.99	18.1%
Deferral/Variance	kWh	1,000			1,000	\$0.0019	\$1.90	\$1.90	
Electricity (Commodity)	kWh	1,064	RPP-Non-res.	\$56.01	1,079	RPP-Non-res.	\$56.90	\$0.89	1.6%
Transmission - Network	kWh	1,064	\$0.0040	\$4.25	1,079	\$0.0040	\$4.32	\$0.07	1.6%
Transmission - Connection	kWh	1,064	\$0.0048	\$5.11	1,079	\$0.0048	\$5.18	\$0.07	1.4%
Wholesale Market Service	kWh	1,064	\$0.0052	\$5.53	1,079	\$0.0052	\$5.61	\$0.08	1.4%
Rural Rate Protection	kWh	1,064	\$0.0010	\$1.06	1,079	\$0.0010	\$1.08	\$0.02	1.9%
Debt Retirement Charge	kWh	1,000	\$0.0007	\$0.70	1,000	\$0.0007	\$0.70		
TOTAL BILL				\$122.36			\$134.38	\$12.02	9.8%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Unmetered Scattered Load

1,250 kWh's

RPP: Non-res.

Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
	Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge			\$4.40			\$11.19	\$6.79	>100%
Distribution	1,250	\$0.0453	\$56.63	1,250	\$0.0475	\$59.38	\$2.75	4.9%
Sub-Total (Distribution)			\$61.03			\$70.57	\$9.54	15.6%
Deferral/Variance	1,250			1,250	\$0.0019	\$2.38	\$2.38	
Electricity (Commodity)	1,330	RPP-Non-res.	\$71.70	1,349	RPP-Non-res.	\$72.81	\$1.11	1.5%
Transmission - Network	1,330	\$0.0040	\$5.32	1,349	\$0.0040	\$5.39	\$0.07	1.3%
Transmission - Connection	1,330	\$0.0048	\$6.38	1,349	\$0.0048	\$6.47	\$0.09	1.4%
Wholesale Market Service	1,330	\$0.0052	\$6.91	1,349	\$0.0052	\$7.01	\$0.10	1.4%
Rural Rate Protection	1,330	\$0.0010	\$1.33	1,349	\$0.0010	\$1.35	\$0.02	1.5%
Debt Retirement Charge	1,250	\$0.0007	\$0.88	1,250	\$0.0007	\$0.88		
TOTAL BILL			\$153.55			\$166.86	\$13.31	8.7%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Unmetered Scattered Load

1,500 kWh's

RPP: Non-res.

Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
	Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge			\$4.40			\$11.19	\$6.79	>100%
Distribution	1,500	\$0.0453	\$67.95	1,500	\$0.0475	\$71.25	\$3.30	4.9%
Sub-Total (Distribution)			\$72.35			\$82.44	\$10.09	13.9%
Deferral/Variance	1,500			1,500	\$0.0019	\$2.85	\$2.85	
Electricity (Commodity)	1,596	RPP-Non-res.	\$87.39	1,618	RPP-Non-res.	\$88.72	\$1.33	1.5%
Transmission - Network	1,596	\$0.0040	\$6.38	1,618	\$0.0040	\$6.47	\$0.09	1.4%
Transmission - Connection	1,596	\$0.0048	\$7.66	1,618	\$0.0048	\$7.77	\$0.11	1.4%
Wholesale Market Service	1,596	\$0.0052	\$8.30	1,618	\$0.0052	\$8.41	\$0.11	1.3%
Rural Rate Protection	1,596	\$0.0010	\$1.60	1,618	\$0.0010	\$1.62	\$0.02	1.3%
Debt Retirement Charge	1,500	\$0.0007	\$1.05	1,500	\$0.0007	\$1.05		
TOTAL BILL			\$184.73			\$199.33	\$14.60	7.9%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Unmetered Scattered Load

2,000 kWh's

RPP: Non-res.

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge				\$4.40			\$11.19	\$6.79	>100%
Distribution	kWh	2,000	\$0.0453	\$90.60	2,000	\$0.0475	\$95.00	\$4.40	4.9%
Sub-Total (Distribution)				\$95.00			\$106.19	\$11.19	11.8%
Deferral/Variance	kWh	2,000			2,000	\$0.0019	\$3.80	\$3.80	
Electricity (Commodity)	kWh	2,127	RPP-Non-res.	\$118.77	2,158	RPP-Non-res.	\$120.55	\$1.78	1.5%
Transmission - Network	kWh	2,127	\$0.0040	\$8.51	2,158	\$0.0040	\$8.63	\$0.12	1.4%
Transmission - Connection	kWh	2,127	\$0.0048	\$10.21	2,158	\$0.0048	\$10.36	\$0.15	1.5%
Wholesale Market Service	kWh	2,127	\$0.0052	\$11.06	2,158	\$0.0052	\$11.22	\$0.16	1.4%
Rural Rate Protection	kWh	2,127	\$0.0010	\$2.13	2,158	\$0.0010	\$2.16	\$0.03	1.4%
Debt Retirement Charge	kWh	2,000	\$0.0007	\$1.40	2,000	\$0.0007	\$1.40		
TOTAL BILL				\$247.08			\$264.31	\$17.23	7.0%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Sentinel Lighting

Volume		RPP?	Distribution Charges		Total Bill	
kWh *	kW		\$ change	% change	\$ change	% change
200	1	Non-res.	\$16.83	>100%	\$17.80	76.7%
2,000	10	Non-res.	\$136.14	>100%	\$146.15	63.0%
4,000	20	Non-res.	\$268.71	>100%	\$288.75	61.5%
6,000	30	Non-res.	\$401.29	>100%	\$431.32	61.0%
8,000	40	Non-res.	\$533.86	>100%	\$573.89	60.8%
10,000	50	Non-res.	\$666.43	>100%	\$716.49	60.6%
20,000	100	Non-res.	\$1,329.29	>100%	\$1,429.40	60.3%

* Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Sentinel Lighting

RPP: Non-res.

200 kWh's

1 kW's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				\$1.35			\$4.92	\$3.57	>100%
Distribution	kW	1	\$6.9632	\$6.96	1	\$20.2204	\$20.22	\$13.26	>100%
Sub-Total (Distribution)				\$8.31			\$25.14	\$16.83	>100%
Deferral/Variance	kW	1			1	\$0.8041	\$0.80	\$0.80	
Electricity (Commodity)	kWh	213	RPP-Non-res.	\$10.64	216	RPP-Non-res.	\$10.79	\$0.15	1.4%
Transmission - Network	kW	1	\$1.2450	\$1.25	1	\$1.2450	\$1.25		
Transmission - Connection	kW	1	\$1.5286	\$1.53	1	\$1.5286	\$1.53		
Wholesale Market Service	kWh	213	\$0.0052	\$1.11	216	\$0.0052	\$1.12	\$0.01	0.9%
Rural Rate Protection	kWh	213	\$0.0010	\$0.21	216	\$0.0010	\$0.22	\$0.01	4.8%
Debt Retirement Charge	kWh	200	\$0.0007	\$0.14	200	\$0.0007	\$0.14		
TOTAL BILL				\$23.19			\$40.99	\$17.80	76.7%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Sentinel Lighting

RPP: Non-res.

2,000 kWh's
 10 kW's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				\$1.35			\$4.92	\$3.57	>100%
Distribution	kW	10	\$6.9632	\$69.63	10	\$20.2204	\$202.20	\$132.57	>100%
Sub-Total (Distribution)				\$70.98			\$207.12	\$136.14	>100%
Deferral/Variance	kW	10			10	\$0.8041	\$8.04	\$8.04	
Electricity (Commodity)	kWh	2,127	RPP-Non-res.	\$118.77	2,158	RPP-Non-res.	\$120.55	\$1.78	1.5%
Transmission - Network	kW	10	\$1.2450	\$12.45	10	\$1.2450	\$12.45		
Transmission - Connection	kW	10	\$1.5286	\$15.29	10	\$1.5286	\$15.29		
Wholesale Market Service	kWh	2,127	\$0.0052	\$11.06	2,158	\$0.0052	\$11.22	\$0.16	1.4%
Rural Rate Protection	kWh	2,127	\$0.0010	\$2.13	2,158	\$0.0010	\$2.16	\$0.03	1.4%
Debt Retirement Charge	kWh	2,000	\$0.0007	\$1.40	2,000	\$0.0007	\$1.40		
TOTAL BILL				\$232.08			\$378.23	\$146.15	63.0%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Sentinel Lighting

RPP: Non-res.

4,000 kWh's
 20 kW's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				\$1.35			\$4.92	\$3.57	>100%
Distribution	kW	20	\$6.9632	\$139.26	20	\$20.2204	\$404.41	\$265.14	>100%
Sub-Total (Distribution)				\$140.61			\$409.33	\$268.71	>100%
Deferral/Variance	kW	20			20	\$0.8041	\$16.08	\$16.08	
Electricity (Commodity)	kWh	4,255	RPP-Non-res.	\$244.28	4,315	RPP-Non-res.	\$247.85	\$3.57	1.5%
Transmission - Network	kW	20	\$1.2450	\$24.90	20	\$1.2450	\$24.90		
Transmission - Connection	kW	20	\$1.5286	\$30.57	20	\$1.5286	\$30.57		
Wholesale Market Service	kWh	4,255	\$0.0052	\$22.12	4,315	\$0.0052	\$22.44	\$0.32	1.4%
Rural Rate Protection	kWh	4,255	\$0.0010	\$4.25	4,315	\$0.0010	\$4.32	\$0.07	1.6%
Debt Retirement Charge	kWh	4,000	\$0.0007	\$2.80	4,000	\$0.0007	\$2.80		
TOTAL BILL				\$469.53			\$758.29	\$288.75	61.5%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Sentinel Lighting

RPP: Non-res.

6,000 kWh's
 30 kW's

Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
	Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge			\$1.35			\$4.92	\$3.57	>100%
Distribution	30	\$6.9632	\$208.90	30	\$20.2204	\$606.61	\$397.72	>100%
Sub-Total (Distribution)			\$210.25			\$611.53	\$401.29	>100%
Deferral/Variance	30			30	\$0.8041	\$24.12	\$24.12	
Electricity (Commodity)	6,382	RPP-Non-res.	\$369.80	6,473	RPP-Non-res.	\$375.15	\$5.35	1.4%
Transmission - Network	30	\$1.2450	\$37.35	30	\$1.2450	\$37.35		
Transmission - Connection	30	\$1.5286	\$45.86	30	\$1.5286	\$45.86		
Wholesale Market Service	6,382	\$0.0052	\$33.19	6,473	\$0.0052	\$33.66	\$0.47	1.4%
Rural Rate Protection	6,382	\$0.0010	\$6.38	6,473	\$0.0010	\$6.47	\$0.09	1.4%
Debt Retirement Charge	6,000	\$0.0007	\$4.20	6,000	\$0.0007	\$4.20		
TOTAL BILL			\$707.03			\$1,138.34	\$431.32	61.0%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Sentinel Lighting

RPP: Non-res.

8,000 kWh's
 40 kW's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				\$1.35			\$4.92	\$3.57	>100%
Distribution	kW	40	\$6.9632	\$278.53	40	\$20.2204	\$808.82	\$530.29	>100%
Sub-Total (Distribution)				\$279.88			\$813.74	\$533.86	>100%
Deferral/Variance	kW	40			40	\$0.8041	\$32.16	\$32.16	
Electricity (Commodity)	kWh	8,510	RPP-Non-res.	\$495.32	8,630	RPP-Non-res.	\$502.44	\$7.12	1.4%
Transmission - Network	kW	40	\$1.2450	\$49.80	40	\$1.2450	\$49.80		
Transmission - Connection	kW	40	\$1.5286	\$61.14	40	\$1.5286	\$61.14		
Wholesale Market Service	kWh	8,510	\$0.0052	\$44.25	8,630	\$0.0052	\$44.88	\$0.63	1.4%
Rural Rate Protection	kWh	8,510	\$0.0010	\$8.51	8,630	\$0.0010	\$8.63	\$0.12	1.4%
Debt Retirement Charge	kWh	8,000	\$0.0007	\$5.60	8,000	\$0.0007	\$5.60		
TOTAL BILL				\$944.50			\$1,518.39	\$573.89	60.8%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Sentinel Lighting

RPP: Non-res.

10,000 kWh's
 50 kW's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				\$1.35			\$4.92	\$3.57	>100%
Distribution	kW	50	\$6.9632	\$348.16	50	\$20.2204	\$1,011.02	\$662.86	>100%
Sub-Total (Distribution)				\$349.51			\$1,015.94	\$666.43	>100%
Deferral/Variance	kW	50			50	\$0.8041	\$40.21	\$40.21	
Electricity (Commodity)	kWh	10,637	RPP-Non-res.	\$620.83	10,788	RPP-Non-res.	\$629.74	\$8.91	1.4%
Transmission - Network	kW	50	\$1.2450	\$62.25	50	\$1.2450	\$62.25		
Transmission - Connection	kW	50	\$1.5286	\$76.43	50	\$1.5286	\$76.43		
Wholesale Market Service	kWh	10,637	\$0.0052	\$55.31	10,788	\$0.0052	\$56.10	\$0.79	1.4%
Rural Rate Protection	kWh	10,637	\$0.0010	\$10.64	10,788	\$0.0010	\$10.79	\$0.15	1.4%
Debt Retirement Charge	kWh	10,000	\$0.0007	\$7.00	10,000	\$0.0007	\$7.00		
TOTAL BILL				\$1,181.97			\$1,898.46	\$716.49	60.6%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Sentinel Lighting

RPP: Non-res.

20,000 kWh's 100 kW's	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				\$1.35			\$4.92	\$3.57	>100%
Distribution	kW	100	\$6.9632	\$696.32	100	\$20.2204	\$2,022.04	\$1,325.72	>100%
Sub-Total (Distribution)				\$697.67			\$2,026.96	\$1,329.29	>100%
Deferral/Variance	kW	100			100	\$0.8041	\$80.41	\$80.41	
Electricity (Commodity)	kWh	21,274	RPP-Non-res.	\$1,248.42	21,576	RPP-Non-res.	\$1,266.23	\$17.81	1.4%
Transmission - Network	kW	100	\$1.2450	\$124.50	100	\$1.2450	\$124.50		
Transmission - Connection	kW	100	\$1.5286	\$152.86	100	\$1.5286	\$152.86		
Wholesale Market Service	kWh	21,274	\$0.0052	\$110.62	21,576	\$0.0052	\$112.20	\$1.58	1.4%
Rural Rate Protection	kWh	21,274	\$0.0010	\$21.27	21,576	\$0.0010	\$21.58	\$0.31	1.5%
Debt Retirement Charge	kWh	20,000	\$0.0007	\$14.00	20,000	\$0.0007	\$14.00		
TOTAL BILL				\$2,369.34			\$3,798.74	\$1,429.40	60.3%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Street Lighting

Volume		RPP?	Distribution Charges		Total Bill	
kWh *	kW		\$ change	% change	\$ change	% change
150	1.00	Non-res.	\$3.64	85.4%	\$4.49	27.9%
500	3.00	Non-res.	\$6.98	85.4%	\$9.58	20.6%
1,000	6.00	Non-res.	\$12.00	85.5%	\$17.36	18.5%
5,000	30.00	Non-res.	\$52.12	85.5%	\$78.87	16.2%
10,000	60.00	Non-res.	\$102.27	85.5%	\$155.77	15.9%
20,000	120.00	Non-res.	\$202.56	85.5%	\$309.56	15.8%
50,000	300.00	Non-res.	\$503.45	85.5%	\$770.92	15.7%

* Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Street Lighting

RPP: Non-res.

150 kWh's

1 kW's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				\$2.31			\$4.28	\$1.97	85.3%
Distribution	kW	1	\$1.9554	\$1.96	1	\$3.6270	\$3.63	\$1.67	85.5%
Sub-Total (Distribution)				\$4.27			\$7.91	\$3.64	85.4%
Deferral/Variance	kW	1			1	\$0.7275	\$0.73	\$0.73	
Electricity (Commodity)	kWh	160	RPP-Non-res.	\$7.98	162	RPP-Non-res.	\$8.09	\$0.11	1.4%
Transmission - Network	kW	1	\$1.2388	\$1.24	1	\$1.2388	\$1.24		
Transmission - Connection	kW	1	\$1.4973	\$1.50	1	\$1.4973	\$1.50		
Wholesale Market Service	kWh	160	\$0.0052	\$0.83	162	\$0.0052	\$0.84	\$0.01	1.2%
Rural Rate Protection	kWh	160	\$0.0010	\$0.16	162	\$0.0010	\$0.16		
Debt Retirement Charge	kWh	150	\$0.0007	\$0.11	150	\$0.0007	\$0.11		
TOTAL BILL				\$16.09			\$20.58	\$4.49	27.9%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Street Lighting

RPP: Non-res.

500 kWh's
 3 kW's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				\$2.31			\$4.28	\$1.97	85.3%
Distribution	kW	3	\$1.9554	\$5.87	3	\$3.6270	\$10.88	\$5.01	85.5%
Sub-Total (Distribution)				\$8.18			\$15.16	\$6.98	85.4%
Deferral/Variance	kW	3			3	\$0.7275	\$2.18	\$2.18	
Electricity (Commodity)	kWh	532	RPP-Non-res.	\$26.59	539	RPP-Non-res.	\$26.97	\$0.38	1.4%
Transmission - Network	kW	3	\$1.2388	\$3.72	3	\$1.2388	\$3.72		
Transmission - Connection	kW	3	\$1.4973	\$4.49	3	\$1.4973	\$4.49		
Wholesale Market Service	kWh	532	\$0.0052	\$2.77	539	\$0.0052	\$2.80	\$0.03	1.1%
Rural Rate Protection	kWh	532	\$0.0010	\$0.53	539	\$0.0010	\$0.54	\$0.01	1.9%
Debt Retirement Charge	kWh	500	\$0.0007	\$0.35	500	\$0.0007	\$0.35		
TOTAL BILL				\$46.63			\$56.21	\$9.58	20.6%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Street Lighting

RPP: Non-res.

1,000 kWh's
 6 kW's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				\$2.31			\$4.28	\$1.97	85.3%
Distribution	kW	6	\$1.9554	\$11.73	6	\$3.6270	\$21.76	\$10.03	85.5%
Sub-Total (Distribution)				\$14.04			\$26.04	\$12.00	85.5%
Deferral/Variance	kW	6			6	\$0.7275	\$4.37	\$4.37	
Electricity (Commodity)	kWh	1,064	RPP-Non-res.	\$56.01	1,079	RPP-Non-res.	\$56.90	\$0.89	1.6%
Transmission - Network	kW	6	\$1.2388	\$7.43	6	\$1.2388	\$7.43		
Transmission - Connection	kW	6	\$1.4973	\$8.98	6	\$1.4973	\$8.98		
Wholesale Market Service	kWh	1,064	\$0.0052	\$5.53	1,079	\$0.0052	\$5.61	\$0.08	1.4%
Rural Rate Protection	kWh	1,064	\$0.0010	\$1.06	1,079	\$0.0010	\$1.08	\$0.02	1.9%
Debt Retirement Charge	kWh	1,000	\$0.0007	\$0.70	1,000	\$0.0007	\$0.70		
TOTAL BILL				\$93.75			\$111.11	\$17.36	18.5%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Street Lighting

RPP: Non-res.

5,000 kWh's
 30 kW's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				\$2.31			\$4.28	\$1.97	85.3%
Distribution	kW	30	\$1.9554	\$58.66	30	\$3.6270	\$108.81	\$50.15	85.5%
Sub-Total (Distribution)				\$60.97			\$113.09	\$52.12	85.5%
Deferral/Variance	kW	30			30	\$0.7275	\$21.83	\$21.83	
Electricity (Commodity)	kWh	5,319	RPP-Non-res.	\$307.04	5,394	RPP-Non-res.	\$311.50	\$4.46	1.5%
Transmission - Network	kW	30	\$1.2388	\$37.16	30	\$1.2388	\$37.16		
Transmission - Connection	kW	30	\$1.4973	\$44.92	30	\$1.4973	\$44.92		
Wholesale Market Service	kWh	5,319	\$0.0052	\$27.66	5,394	\$0.0052	\$28.05	\$0.39	1.4%
Rural Rate Protection	kWh	5,319	\$0.0010	\$5.32	5,394	\$0.0010	\$5.39	\$0.07	1.3%
Debt Retirement Charge	kWh	5,000	\$0.0007	\$3.50	5,000	\$0.0007	\$3.50		
TOTAL BILL				\$486.57			\$565.44	\$78.87	16.2%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Street Lighting

RPP: Non-res.

10,000 kWh's
 60 kW's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				\$2.31			\$4.28	\$1.97	85.3%
Distribution	kW	60	\$1.9554	\$117.32	60	\$3.6270	\$217.62	\$100.30	85.5%
Sub-Total (Distribution)				\$119.63			\$221.90	\$102.27	85.5%
Deferral/Variance	kW	60			60	\$0.7275	\$43.65	\$43.65	
Electricity (Commodity)	kWh	10,637	RPP-Non-res.	\$620.83	10,788	RPP-Non-res.	\$629.74	\$8.91	1.4%
Transmission - Network	kW	60	\$1.2388	\$74.33	60	\$1.2388	\$74.33		
Transmission - Connection	kW	60	\$1.4973	\$89.84	60	\$1.4973	\$89.84		
Wholesale Market Service	kWh	10,637	\$0.0052	\$55.31	10,788	\$0.0052	\$56.10	\$0.79	1.4%
Rural Rate Protection	kWh	10,637	\$0.0010	\$10.64	10,788	\$0.0010	\$10.79	\$0.15	1.4%
Debt Retirement Charge	kWh	10,000	\$0.0007	\$7.00	10,000	\$0.0007	\$7.00		
TOTAL BILL				\$977.58			\$1,133.35	\$155.77	15.9%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Street Lighting

RPP: Non-res.

20,000 kWh's
 120 kW's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				\$2.31			\$4.28	\$1.97	85.3%
Distribution	kW	120	\$1.9554	\$234.65	120	\$3.6270	\$435.24	\$200.59	85.5%
Sub-Total (Distribution)				\$236.96			\$439.52	\$202.56	85.5%
Deferral/Variance	kW	120			120	\$0.7275	\$87.30	\$87.30	
Electricity (Commodity)	kWh	21,274	RPP-Non-res.	\$1,248.42	21,576	RPP-Non-res.	\$1,266.23	\$17.81	1.4%
Transmission - Network	kW	120	\$1.2388	\$148.66	120	\$1.2388	\$148.66		
Transmission - Connection	kW	120	\$1.4973	\$179.68	120	\$1.4973	\$179.68		
Wholesale Market Service	kWh	21,274	\$0.0052	\$110.62	21,576	\$0.0052	\$112.20	\$1.58	1.4%
Rural Rate Protection	kWh	21,274	\$0.0010	\$21.27	21,576	\$0.0010	\$21.58	\$0.31	1.5%
Debt Retirement Charge	kWh	20,000	\$0.0007	\$14.00	20,000	\$0.0007	\$14.00		
TOTAL BILL				\$1,959.61			\$2,269.17	\$309.56	15.8%

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Street Lighting

RPP: Non-res.

50,000 kWh's
 300 kW's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				\$2.31			\$4.28	\$1.97	85.3%
Distribution	kW	300	\$1.9554	\$586.62	300	\$3.6270	\$1,088.10	\$501.48	85.5%
Sub-Total (Distribution)				\$588.93			\$1,092.38	\$503.45	85.5%
Deferral/Variance	kW	300			300	\$0.7275	\$218.25	\$218.25	
Electricity (Commodity)	kWh	53,185	RPP-Non-res.	\$3,131.17	53,940	RPP-Non-res.	\$3,175.71	\$44.54	1.4%
Transmission - Network	kW	300	\$1.2388	\$371.64	300	\$1.2388	\$371.64		
Transmission - Connection	kW	300	\$1.4973	\$449.19	300	\$1.4973	\$449.19		
Wholesale Market Service	kWh	53,185	\$0.0052	\$276.56	53,940	\$0.0052	\$280.49	\$3.93	1.4%
Rural Rate Protection	kWh	53,185	\$0.0010	\$53.19	53,940	\$0.0010	\$53.94	\$0.75	1.4%
Debt Retirement Charge	kWh	50,000	\$0.0007	\$35.00	50,000	\$0.0007	\$35.00		
TOTAL BILL				\$4,905.68			\$5,676.60	\$770.92	15.7%