Centre Wellington Hydro Ltd.
730 Gartshore St.
P.O. Box 217
Fergus
Ontario N1M 2W8

August 15, 2008

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

Dear Ms. Walli,

Centre Wellington Hydro Ltd. – License #ED-2002-0498
Requirement and Rate Application for the 2009, 2010 and 2011 rate years
OEB File No.: EB-2008-0225

Please find attached Centre Wellington Hydro Ltd's Application for revenue requirements and corresponding rates for three individual and successive rate years commencing May 1, 2009 and ending April 30, 2012. This application is being filed pursuant to the Board's e-Filing Services. We will be delivering two paper copies of the Application to the Board on Friday 15th August 2008.

Yours very truly,

Florence E Thiessen

Florence Thiessen, CGA
Vice President / Treasurer
Centre Wellington Hydro Ltd.
Email: thiessen@cwhydro.ca
Phone: (519) 843-2900 Ext 225

Centre Wellington Hydro Ltd.

2009 EDR Application

EB-2008-0225

Submitted: 15 August, 2008

CENTRE WELLINGTON HYDRO LTD
730 GARTSHORE ST., P.O. BOX 217
FERGUS, ON N1M 2W8

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Application

ONTARIO ENERGY BOARD

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 Centre Wellington Hydro to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other charges for the distribution of electricity to be effective May 1, 2009;

APPLICATION

Introduction

The Applicant is Centre Wellington Hydro (referred to in this Application as the "Applicant"). The Applicant is a corporation incorporated pursuant to the Ontario Business Corporations Act with its head office in the Town of Fergus.

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 9/Tab 1/Schedule 8 and the material being filed in support of this Applications sets out the Applicant'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 Applicant requests, that if for any reason final rates are not approved, that interim rates be approved effective May 1, 2009 until final rates are approved by the Board. The Applicant requests the interim rates would be those proposed in this Application.

The Proposed Distribution Rates and Other Charges are Just and Reasonable

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

- the proposed rates for the distribution of electricity have been prepared in accordance with the Filing Requirements;

- the proposed rates are necessary to maintain safe, reliable distribution service to its customers and to meet the Applicant's Market Based Return ("MBRR"), Debt Rate and Payments in Lieu of Taxes ("PILS") requirements;

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

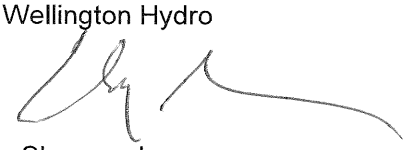
- such other grounds as may be set out in the material accompanying this Application Summary.

Relief Sought

The Applicant applies for an Order or Orders approving the proposed distribution rates and other charges 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.

DATED at Fergus, Ontario this 15 day of August, 2008

Centre Wellington Hydro



Douglas Sherwood
President / Secretary

Summary of Application

Purpose and Need

The Applicant's revenue requirement for 2009 contemplates the recovery of its costs of providing distribution service; its permitted Return on Equity and the funds necessary to service its debt (based on the OEB's deemed debt/equity ratio which is subject to adjustment this year to move it toward the OEB-mandated 60% debt / 40% equity); and its Payments in Lieu of Taxes ("PILS"). When its forecasted customers and volumes for 2009 are taken into account, the Applicant estimates that its present rates will produce a deficiency in distribution revenue of $365,167 for the 2009 Test Year. Excluded from this estimate is the impact of energy costs. The Applicant therefore seeks the Board's approval to revise its rates applicable to its distribution of electricity. The issues to be reviewed in this case, as the applicant sees them, are discussed below.

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

The applicant's forecast is based on a Total Rate Base of $8,818,124 consisting of a Net Fixed Asset balance of $6,850,701 and a Working Capital Allowance of $1,967,423. The Deemed Capital Structure for 2009 has been revised to move closer to the 60/40 Debt/Equity Ratio. The Capital Structure for 2009 is as follows:

Short Term Debt	4.00%
Long Term Debt	52.67%
Total Equity	43.33%

Through this Application, the Applicant seeks to:

- recover a Revenue Deficiency in the amount of $216,645 arising from changes in OM&A, Amortization, Rate of Return and PILS
- dispose of Regulatory Assets December 31, 2007 balances plus interest to April 30, 2009 for accounts 1508, 1550, 1584 and 1586 by crediting back the amount of $777,480 or $259,160 per year over a three (3) year period by way of a rate rider
- update its Total Loss Factor from 1.0472 to 1.0681
- revise its transmission rates to better reflect a match between connection and network revenues and costs
- recover the following revenue requirement over the rate period:
    - Service Revenue Requirement $ 3,075,196
    - Less Revenue Offsets $ 335,443
    - Base Revenue Requirement $ 2,739,753
- receive approval for a 2008 and 2009 capital expenditure program of $512,600 and $815,600, respectively
- Receive approval for a 2009 OM&A program of $1,746,600 plus amortization expenses of $638,185
- move all customer classes closer to a Revenue to Cost Ratio of 1.0 using the results of the Cost Allocation filing and maintain the Fixed Monthly Service Charges within the parameters set by the Board in the November 28, 2007 Cost Allocation report.

Other than the Street Lighting and Sentinel Lighting Customer Classes, the applicant submits that approval of the proposed 2009 rates will not require rate mitigation for the remaining classes. The applicant is asking to phase in the Revenue to cost Ratios for the Street lighting and Sentinel Lighting customer classes which will bring them to a ratio of 0.7 over a three year period which includes 2 years of the IRM process following this Cost of Service Application.

The Applicant has been assisted in preparing this application by Elenchus Research Associates who provided the model used in the determination of just and reasonable 2009 Distribution Rates. The Applicant has based this Application on its forecasted results for the 2009 Test Year. As required by the OEB, The Applicant is also presenting the historical actual information

for fiscal 2006 and 2007; information for the OEB-approved 2006 test year; and forecast information for the fiscal 2008 bridge year.

Current Rates Schedule

Centre Wellington Hydro Ltd.
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-2007-0814

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	13.28
Distribution Volumetric Rate	$/kWh	0.0153
Retail Transmission Rate – Network Service Rate	$/kWh	0.0039
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0062
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	$	13.96
Distribution Volumetric Rate	$/kWh	0.0177
Retail Transmission Rate – Network Service Rate	$/kWh	0.0035
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0055
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 2,999 kW

Service Charge	$	42.23
Distribution Volumetric Rate	$/kW	2.9804
Retail Transmission Rate – Network Service Rate	$/kW	1.4327
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.2069
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	1.5153
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Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered >1,000kW	$/kW	2.4407
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 3,000 to 4,999 kW

Service Charge	$	558.28
Distribution Volumetric Rate	$/kW	1.6740
Retail Transmission Rate – Network Service Rate	$/kW	1.6024
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.6029
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)	$	14.29
Distribution Volumetric Rate	$/kWh	0.0177
Retail Transmission Rate – Network Service Rate	$/kWh	0.0035
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0055
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Centre Wellington Hydro Ltd.
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-2007-0814

Sentinel Lighting

Service Charge (per connection)	$	0.46
Distribution Volumetric Rate	$/kW	1.7575
Retail Transmission Rate – Network Service Rate	$/kW	1.0860
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7418
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)	$	0.16
Distribution Volumetric Rate	$/kW	1.0613
Retail Transmission Rate – Network Service Rate	$/kW	1.0805
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7061
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
Request for Other Billing Information	$	15.00
Easement Letter	$	15.00
Notification Charge	$	15.00
Account History	$	15.00
Returned Cheque (Plus Bank Charges)	$	15.00
Charge to Certify Cheque	$	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 Disconnection	$	30.00
Collection of Account Charge – No Disconnection – After Regular Hours	$	165.00
Disconnect/Reconnect Charge – At Meter – During Regular Hours	$	65.00
Disconnect/Reconnect Charge – At Meter – After Hours	$	185.00
Disconnect/Reconnect Charge – At Pole – During Regular Hours	$	185.00
Disconnect/Reconnect Charge – At Pole – After 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 & Remove – Overhead – No Transformer	$	500.00
Temporary Service Install & Remove – Underground – No Transformer	$	300.00
Temporary Service Install & Remove – Overhead – With Transformer	$	1000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Centre Wellington Hydro Ltd.
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-2007-0814

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	1.0472
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0367
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Proposed Rates Schedule

		Effective May 1/09
Residential		
Service Charge	$	14.27
Distribution Volumetric Rate	$/kWh	0.0136
Regulatory Asset Recovery	$/kWh	(0.0033)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0046
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
General Service Less Than 50 kW		
Service Charge	$	15.71
Distribution Volumetric Rate	$/kWh	0.0167
Regulatory Asset Recovery	$/kWh	(0.0022)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0050
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
General Service 50 to 2,999 kW		
Service Charge	$	130.72
Distribution Volumetric Rate	$/kW	3.2671
Regulatory Asset Recovery	$/kW	(0.3125)
Retail Transmission Rate – Network Service Rate	$/kW	2.0328
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6548
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 3,000 to 4,999 kW		
Service Charge	$	558.55
Distribution Volumetric Rate	$/kW	2.7283
Regulatory Asset Recovery	$/kW	(0.2122)
Retail Transmission Rate – Network Service Rate	$/kW	2.2736
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9518
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	$	16.65
Distribution Volumetric Rate	$/kWh	0.0269
Regulatory Asset Recovery	$/kWh	(0.0017)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0050
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	2.72
Distribution Volumetric Rate	$/kW	7.4289
Regulatory Asset Recovery	$/kW	(0.3108)
Retail Transmission Rate – Network Service Rate	$/kW	1.5409
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3061
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)	$	2.36
Distribution Volumetric Rate	$/kW	11.6642
Regulatory Asset Recovery	$/kW	(0.2086)
Retail Transmission Rate – Network Service Rate	$/kW	1.5331
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2793
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

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
Retailer Service Agreement -- standard charge	$	100.00
Retailer Service Agreement -- monthly fixed charge (per retailer)	$	20.00
Retailer Service Agreement -- monthly variable charge (per customer)	$	0.50
Distributor-Consolidated Billing -- monthly charge (per customer)	$	0.30
Retailer-Consolidated Billing -- monthly credit (per customer)	$	(0.30)
Service Transaction Request -- request fee (per request)	$	0.25
Service Transaction Request -- processing fee (per processed request)	$	0.50

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 <5000 kW	1.0681
Primary Metered Customer <5000 kW	1.0574

Summary of Bill Impacts

The following tables provides a summary of the rate impacts for each of the classes based on the proposed 2009 rates and various Volumes

Residential

Volume		RPP	Distribution Charges		Total Bill	
kWh *	kW	Rate Class	$ change	% change	$ change	% change
500		Summer	$0.14	0.7%	($0.77)	(1.3%)
1,000		Summer	($0.71)	(2.5%)	($2.34)	(2.1%)
1,500		Summer	($1.56)	(4.3%)	($4.02)	(2.5%)
500		Winter	$0.14	0.7%	($0.77)	(1.3%)
1,000		Winter	($0.71)	(2.5%)	($2.34)	(2.2%)
1,500		Winter	($1.56)	(4.3%)	($4.02)	(2.6%)

General Service <50 kW

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
2,000		Non-res.	($0.25)	(0.5%)	($1.34)	(0.6%)
3,000		Non-res.	($1.25)	(1.9%)	($2.93)	(0.9%)
5,000		Non-res.	($3.25)	(3.2%)	($6.03)	(1.2%)
10,000		Non-res.	($8.25)	(4.3%)	($13.78)	(1.3%)
17,500		Non-res.	($15.75)	(4.9%)	($25.44)	(1.4%)

General Service 50 – 2,999 kW

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
20,164	74	n/a	$109.71	41.7%	$115.72	5.9%
46,278	91	n/a	$114.58	36.6%	$149.22	3.8%
179,400	396	n/a	$202.02	16.5%	$324.91	2.1%
294,372	901	n/a	$346.81	12.7%	$482.03	1.8%
1,182,146	2,241	n/a	$730.98	10.9%	$1,638.15	1.7%

General Service 3,000 – 4,999 kW

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
1,302,474	3,556	n/a	$3,749.36	57.6%	$4,718.69	4.2%
1,492,765	3,696	n/a	$3,896.96	57.8%	$5,080.81	4.0%
1,939,602	3,758	n/a	$3,962.33	57.9%	$5,701.12	3.6%

Unmetered Scattered Load

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
32,000		Non-res.	$296.76	51.1%	$295.06	9.0%
34,000		Non-res.	$315.16	51.2%	$313.36	9.0%
36,000		Non-res.	$333.56	51.2%	$331.63	9.0%

Sentinel Lighting

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
82	0.23	Non-res.	$3.55	>100%	$3.58	51.8%
92	0.25	Non-res.	$3.70	>100%	$3.72	48.4%

Street Lighting

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
44	0.16	Non-res.	$3.84	>100%	$3.87	>100%
64	0.16	Non-res.	$3.84	>100%	$3.90	78.5%

List of Issues

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

Capital Structure:

The Applicant's current deemed capital structure is 53.3% debt / 46.7% equity. In its December 20, 2006 Report 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, the Applicant is requesting a change in its deemed capital structure. Specifically, the Applicant is requesting a decrease in the deemed equity ratio from 46.7% to 43.3% and a corresponding increase in Debt from 53.3% to 56.7% consistent with the 3 year phase-in of the Applicant's capital structure to a 60/40 Debt to Equity capital structure.

Return on Equity:

In addition, the Applicant 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. The Applicant understands the OEB will be finalizing the return on equity for 2009 rates based on January 2009 market interest rate information.

Smart Meter Infrastructure:

The Applicant has not included any forecasted costs related to Smart Metering. The Board previously approved $0.27 per month per metered customer which is anticipated to continue in the Rate Application until it is determined how the applicant will proceed with the installation of Smart Meters. At the present time, the applicant is waiting to be included in the provincial regulations to allow proceeding with the purchase and installation of Smart Meters. It is the intention of the applicant to meet the provincial target of having smart meters installed on all residential and small commercial accounts by the end of 2010.

Revised Transmission Network and Connection Rates

The Applicant is applying for new Network and Connection Charges for all classes because the current rate structure has resulted in a large net credit balance. The Applicant feels that the new rate structure will result in a better match of revenue to the actual expenditures. The Applicant has not included the new proposed 9% rate increase in Hydro One Networks rate application on the direction received from the OEB at the time of this application.

Cost of Service Application Costs

The Applicant has estimated the cost of preparing the 2009 Cost of Service application to be $102,000 to be recovered over three years. This cost includes incremental cost only and not those cost already included in the current rate structure. The Applicant is proposing that the cost be amortized over a three year period starting in 2009.

Future Storm Losses

The Applicant is not applying for recovery of Storm Loss Insurance premiums at this time because the projected premiums compared to the recorded storm losses over the last six years does not justify the expenditures. The Applicant may have to apply for a z-factor in the future if storm losses become material.

List of Specific Approvals Requested

The Applicant requests the following specific approvals:

1. Approval to charge distribution rates listed in the proposed Rate Schedule, Exhibit 1, Tab 1, Schedule 5, pages 1 & 2, effective May 1, 2009 to recover a gross base revenue requirement of $2,915,601.

2. Approval of our Specific Service charges listed in the proposed Rate Schedule, Exhibit 1, Tab 1, Schedule 5, pages 1 & 2

3. Approval of the Applicant's proposed change in capital structure involving the decrease of the deemed common equity component from 46.7% to 43.3% and the increase of deemed debt from 53.3% to 56.7% 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.

4. Approval of the proposed Total Loss Factor in of 1.0681 which includes a Supply Facilities Loss Factor of 1.0299% and a Distribution Loss Factor of 1.0370%

5. Approval to revise the the transmission network and connection charges as outlined in the following table:

Table 1 - Revised transmission network and connection charges

Network	**Customer Class Name**	**2008 Rate**	**2009 Rate**
kWh	Residential	$0.0039	$0.0055
kWh	General Service Less Than 50 kW	$0.0035	$0.0050
kW	General Service 50 to 2,999 kW	$1.4327	$2.0328
kW	General Service 3,000 to 4,999 kW	$1.6024	$2.2736
kWh	Unmetered Scattered Load	$0.0035	$0.0050
kW	Sentinel Lighting	$1.0860	$1.5409
kW	Street Lighting	$1.0805	$1.5331
Connection	**Customer Class Name**	**2008 Rate**	**2009 Rate**
kWh	Residential	$0.0062	$0.0046
kWh	General Service Less Than 50 kW	$0.0055	$0.0041
kW	General Service 50 to 2,999 kW	$2.2069	$1.6548
kW	General Service 3,000 to 4,999 kW	$2.6029	$1.9518
kWh	Unmetered Scattered Load	$0.0055	$0.0041
kW	Sentinel Lighting	$1.7418	$1.3061
kW	Street Lighting	$1.7061	$1.2793

6. Approval to dispose of deferral accounts 1508, 1550, 1584, and 1586 having a total net credit balance of $777,480. The applicant is requesting the balance be returned to the customers over a 3 year period with the use of a deferral account rate rider commencing May 1, 2009.

Schedule of Overall Revenue Deficiency/Sufficiency

	2009 Projection	2008 Projection	Var #	Var %
Utility Income	470,927	537,453	(66,526)	(12.4%)
Utility Rate Base	8,818,124	8,842,442	(24,318)	(0.3%)
Indicated Rate of Return	5.34%	6.08%	(0.74%)	(12.1%)
Requested / Approved Rate of Return	7.71%	7.71%		
Sufficiency / (Deficiency) in Return	(2.37%)	(1.63%)	(0.74%)	(45.2%)
Net Revenue Sufficiency / (Deficiency)	**(209,018)**	**(144,367)**	**(64,651)**	**(44.8%)**
Provision for PILs/Taxes *	(7,627)	(7,647)	21	0.3%
Gross Revenue Sufficiency / (Deficiency)	**(216,645)**	**(152,014)**	**(64,631)**	**(42.5%)**
Deemed Overall Debt Rate	*7.05%*	*7.25%*	*(0.20%)*	*(2.7%)*
Deemed Cost of Debt	*352,472*	*320,539*	*31,934*	*10.0%*
Utility Income less Deemed Cost of Debt	*118,455*	*216,915*	*(98,460)*	*(45.4%)*
Return On Deemed Equity	*3.10%*	*5.66%*	*(2.56%)*	*(45.2%)*
UTILITY INCOME				
Total Net Revenues **	2,858,551	2,891,576	(33,024)	(1.1%)
OM&A Expenses	1,711,600	1,699,900	11,700	0.7%
Depreciation & Amortization	638,185	594,185	43,999	7.4%
Taxes other than PILs / Income Taxes	35,000	33,000	2,000	6.1%
Total Costs & Expenses	2,384,785	2,327,085	57,699	2.5%
Utility Income before Income Taxes / PILs	473,767	564,490	(90,724)	(16.1%)
PILs / Income Taxes	2,839	27,037	(24,198)	(89.5%)
Utility Income	**470,927**	**537,453**	**(66,526)**	**(12.4%)**

** 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.*

*** excludes deferral account interest recorded to a revenue account (e.g. #4405)*

Causes of the Deficiency/Sufficiency

The Applicant's net revenue deficiency is calculated as $209,018 and when grossed up for PILs the revenue deficiency is $216,645. The Applicants calculation of its 2009 revenue deficiency is provided in Schedule 9 of this Exhibit.

The forecasted revenue deficiency is mainly attributable to the fact that the 2006 EDR rates do not reflect forecasted increases in OM&A costs and Capital Investments.

The 2006 EDR was based on historic (average of 2003 & 2004) net fixed assets balances, and the 2004 additions were subject to the half year rule.

The Applicant has made significant capital investments through the period 2004 – 2007 and will continue to invest in Capital projects in 2008 and 2009.

This increase in investments, results in an increase in return on capital, depreciation expense and in working capital.

Board Findings and Directions from 2007 EDR

There are no Board Findings and Directions from the 2007 EDR for the Applicant.

Board Findings and Directions from 2006 EDR

There are no Board Findings and Directions from the 2006 EDR for the Applicant.

Status of Board Directives

Not Applicable.

Company Overview

Utility Description and Overview

The Applicant, Centre Wellington Hydro is the electricity distributor licensed by the Ontario Energy Board to serve the Municipality of the Township of Centre Wellington. The Applicant was incorporated under the Business Corporations Act (Ontario) on August 22, 2000. The sole shareholder of the Applicant is the Municipality of the Township of Centre Wellington. The Applicant's long-term debt is held entirely by the Shareholder, the Municipality of the Township of Centre Wellington.

Even though the Applicant is 100% owned by the Township of Centre Wellington, the Applicant acts totally independent of council. The Applicant is governed by a board of directors, and regulated by the Ontario Energy Board.

The Applicant currently serves approximately 6160 residential, commercial, industrial and institutional customers. The service area is comprised of the geographical area of the former Town of Fergus and Village of Elora.

The Applicant employs a full-time workforce of 12 skilled employees who are dedicated to delivering a safe and reliable supply of electricity to customers. The workforce of 12 includes 4 employees who are represented by IBEW.

Utility Description

COMMUNITY SERVED:	Town of Fergus & the Village of Elora
TOTAL SERVICE AREA:	10.71 sq. km.
RURAL SERVICE AREA:	None
DISTRIBUTION TYPE:	Electricity
SERVICE AREA POPULATION:	18,156
MUNICIPAL POPULATION:	26,520

BOUNDARIES:

The distribution License authorizes the Applicant to distribute and sell electricity within the boundaries as stated below:

1. The former Town of Fergus as of December 31, 1998, now in the Township of Centre Wellington.

2. The former Village of Elora as of December 31, 1998, now in the Township of Centre Wellington.

3. Plan 61R9227, Part of Lot 14, Concession 2 of the former Township of Nichol, now within the Township of Centre Wellington and having municipal address of 950 Scotland Street.

4. 6497 Beatty Line North, Con 15, PT Lot 20 Plan 71 PT, Park Lots 14, 16 & 18 Desc Inc RP 61R5701 Part 3 47.42 AC in the former Township of Nichol.

Contact Information

Douglas Sherwood
President / Secretary
Centre Wellington Hydro Ltd
730 Gartshore Street, P.O. Box 217, Fergus, ON N1M 2W8
Email: sherwood@cwhydro.ca
Telephone: 519-843-2900 Ext 224
Cell Number: 519-835-8344
Fax: 519-843-4389

Florence Thiessen, CGA
Vice President / Treasurer
Centre Wellington Hydro Ltd
730 Gartshore Street, P.O. Box 217, Fergus, ON N1M 2W8
Email: thiessen@cwhydro.ca
Telephone: 519-843-2900 Ext 225
Cell Number: 519-400-2223
Fax: 519-843-4389 or 519-843-7601

Neighboring Utilities

The Applicant is surrounded by Hydro One Networks with their nearest area office being located in Guelph.

Waterloo North Hydro's service area is approximately 20 kilometers to the west.

Guelph Hydro is approximately 20 kilometers to the south.

Wellington North Power is approximately 20 kilometers to the north.

Orangeville Hydro is approximately 35 kilometers to the east

Host or Embedded Utilities

The Applicant is not a host utility and there are no embedded utilities in its distribution service area.

The Applicant is an embedded distributor within Hydro One's service territory. The Applicant is a registered Market Participant dealing directly with the IESO and has three metering points of which two are metered by the Applicant and one is metered by Hydro One. The metering point that is metered by Hydro One is the subtractive meter going out of Elora. As an embedded utility, the Applicant is billed monthly by Hydro One for Transmission Charges.

LDC's Distribution License

Distribution License

Ontario

Electricity Distribution Licence

ED-2002-0498

Centre Wellington Hydro Ltd

Valid Until
November 30, 2023

Mark C. Garner
Managing Director, Market Operations
Ontario Energy Board
Date of Issuance: December 1, 2003
Date of Amendment: September 22, 2004
Date of Amendment: March 11, 2005

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: Centre Wellington Hydro Ltd;

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

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

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

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

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

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

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

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

2 Interpretation

18

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

3 Authorization

20

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

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

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

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

25

4 Obligation to Comply with Legislation, Regulations and Market Rules

26

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.

27

4.2 The Licensee shall comply with all applicable Market Rules.

28

5 Obligation to Comply with Codes

29

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:

30

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

31

b) the Distribution System Code;

32

c) the Retail Settlement Code; and

33

d) the Standard Supply Service Code.

34

5.2 The Licensee shall:

35

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

36

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.

37

6 Obligation to Provide Non-discriminatory Access

38

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.

39

7 Obligation to Connect

40

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

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

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

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

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

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

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

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

8 Obligation to Sell Electricity

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

9 Obligation to Maintain System Integrity

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

10 Market Power Mitigation Rebates

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

54

11 Distribution Rates

55

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

56

12 Separation of Business Activities

57

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

58

13 Expansion of Distribution System

59

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

60

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

61

14 Provision of Information to the Board

62

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

63

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

64

15 Restrictions on Provision of Information

65

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

66

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

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

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

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

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

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

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

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

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

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

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

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

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

17 Term of Licence

17.1 This Licence shall take effect on December 1, 2003 and expire on November 30, 2023. The term of this Licence may be extended by the Board.

18 Fees and Assessments

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

19 Communication

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

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

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

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

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

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

20 Copies of the Licence

20.1 The Licensee shall:

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

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

96

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

97

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

98

1. The former Town of Fergus as of December 31, 1998, now in the Township of Centre Wellington.

99

2. The former Village of Elora as of December 31, 1998, now in he Township of Centre Wellington.

100

3. Plan 61R9227, Part of Lot 14, Concession 2 of the former Township of Nichol, now within the Township of Centre Wellington and having municipal address of 950 Scotland Street.

101

4. 6497 Beatty Line North, Con 15, PT Lot 20 Plan 71 PT, Park Lots 14, 16 & 18 Desc Inc RP 61R5701 Part 3 47.42 AC in the former Township of Nichol.

101

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

102

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.

103

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.

104

SCHEDULE 3 LIST OF CODE EXEMPTIONS

105

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

106

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.

107

APPENDIX A MARKET POWER MITIGATION REBATES

108

1 Definitions and Interpretation

109

In this Licence,

110

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

111

"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;

112

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

113

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

114

2 Information Given to IMO

115

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:

116

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

117

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.*

118

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:

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

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

121 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.

122 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.

123 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.

124 ## 3 Pass Through of Rebate

125 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:

126 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;

127 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

128 c embedded distributors to whom the distributor distributes electricity.

129 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.

130 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:

131 "ONTARIO POWER GENERATION INC. rebate"

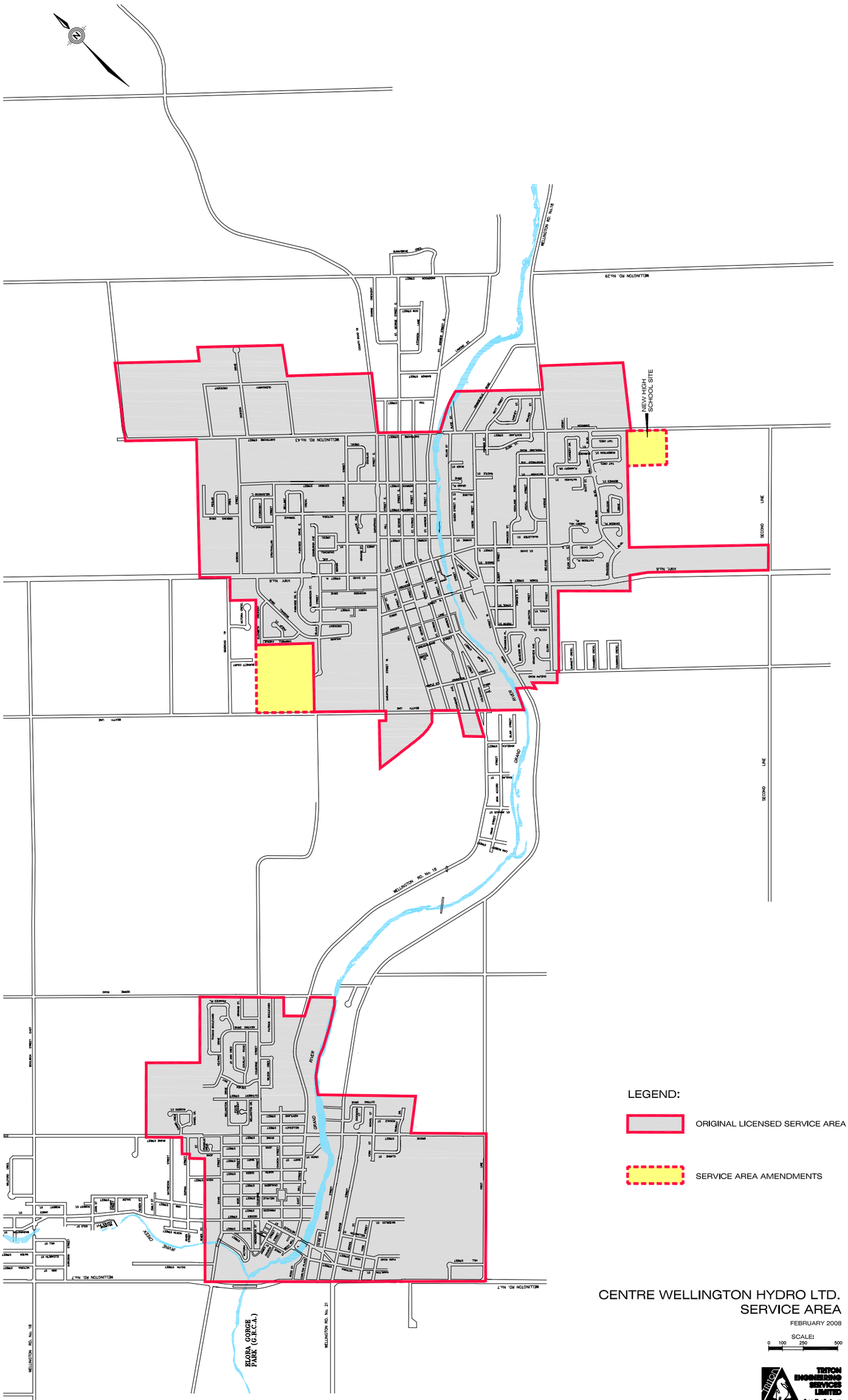
132 Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IMO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on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

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

134 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.

Map of LDC's Distribution System

A copy of the Applicant's distribution system map is set out on the next page.



LEGEND:

ORIGINAL LICENSED SERVICE AREA

SERVICE AREA AMENDMENTS

CENTRE WELLINGTON HYDRO LTD.
SERVICE AREA

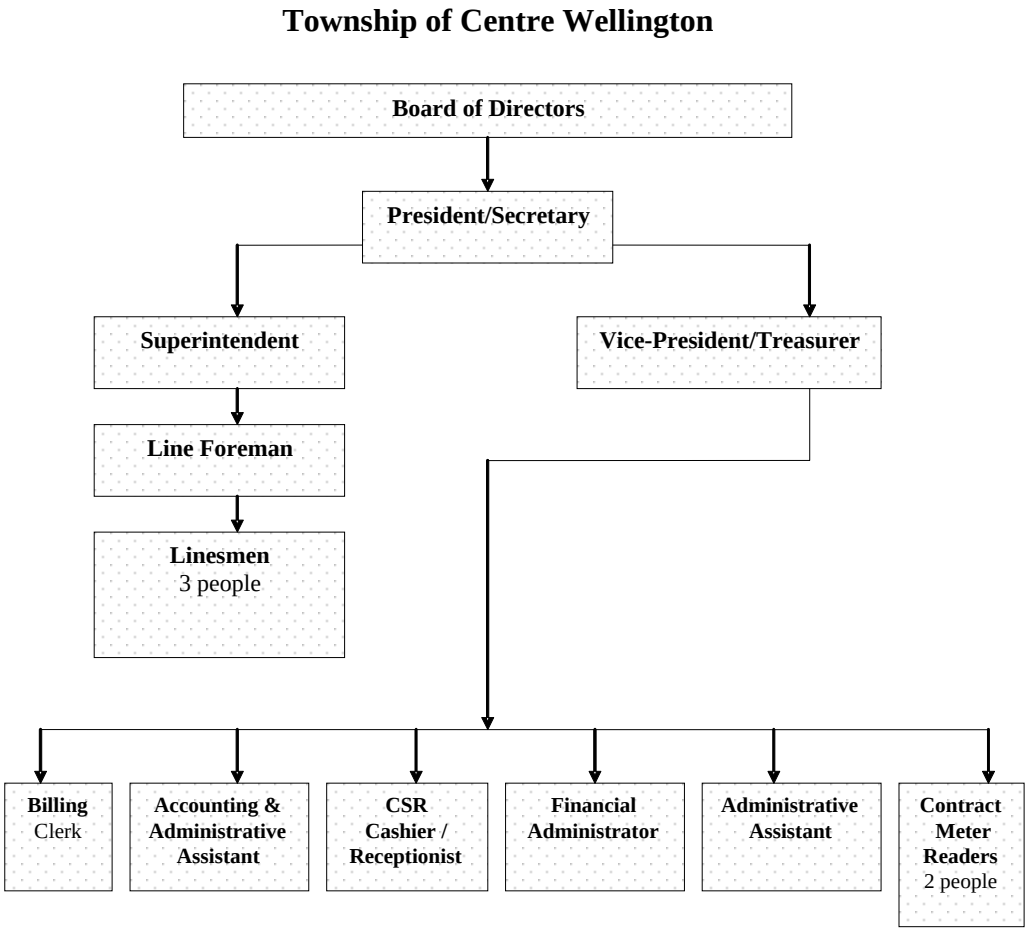
FEBRUARY 2008

SCALE:

0 100 250 500

TRITON ENGINEERING SERVICES LIMITED
Consulting Engineers

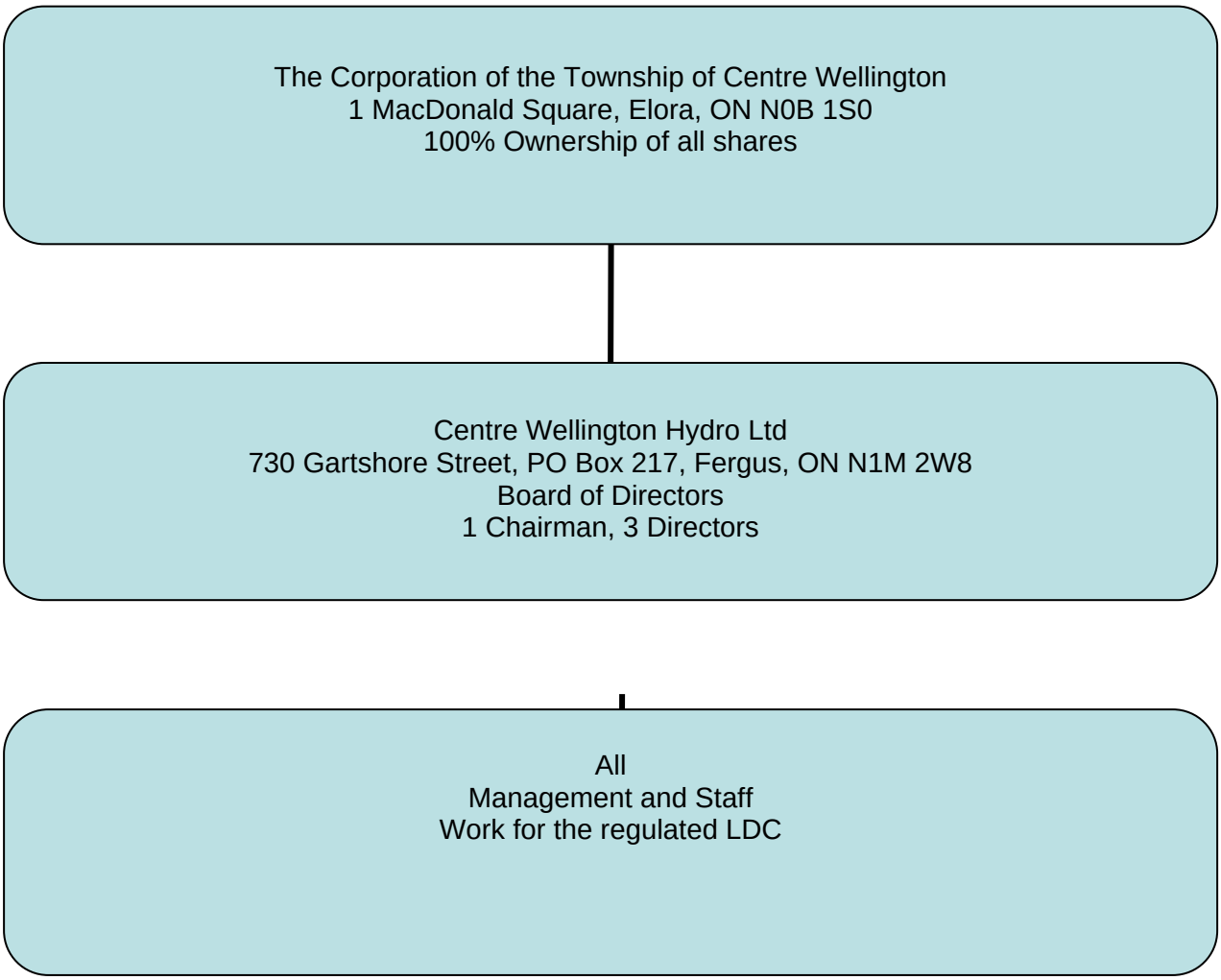
Utility Organizational Chart



Corporate Entities Relationships Chart

The Applicant's 2008 Shareholder Organizational Chart

The Corporation of the Township of Centre Wellington is the 100% Shareholder of the Applicant. The Applicant has no affiliate corporations other than the Corporation of the Township of Centre Wellington.



Planned Changes in Corporate or Operational Structure

As of the date of this application, the Applicant does not have any planned changes in corporate and operational structure.

Conditions of Service/Service Charges

The preparation of the Condition of Service was a joint effort of the Cornerstone Hydro-Electric Concepts Inc (CHEC) group. This is one of the many initiatives that the group worked collaboratively on to seek cost savings and other efficient synergies.

CONDITIONS OF SERVICE

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Contact Information

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.

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 Distributor, at the expense of the Owner, reserves the right to provide an Inspector who will be on duty for the duration of the work, and the Contractor shall supply him such accommodations as he may require. The Inspector shall have the authority to stop work at any time he feels the Contractor is not proceeding in accordance with these "conditions of service". Work shall not recommence until the Distributor has been notified and the Inspector is present at the site.

Customers may be required to pay Capital Contributions for the addition of new electrical services in accordance to calculations on overall system cost impact.

1.2 Related Codes and Governing Laws

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

1. *Electricity Act, 1998*
   http://www.collus.com/cos/Electricity Act, 1998, S_O_ 1998, c_ 15, Sched_ A.htm
2. *Ontario Energy Board Act, 1998*
   http://www.collus.com/cos/Ontario Energy Board Act, 1998, S_O_ 1998, c_ 15, Sched_ B.htm
3. *Distribution Licence*
   HOTLINK
4. *Affiliate Relationships Code*
   http://www.collus.com/cos/Affiliate Relationships Code.pdf
5. *Distribution System Code*
   http://www.collus.com/cos/Distribution System Code.pdf
6. *Retail Settlements Code*
   http://www.collus.com/cos/Retail Settlement Code.pdf
7. *Standard Service Supply Code*
   http://www.collus.com/cos/Standard Service Supply Code.pdf

8. *Transmission System Code*
   http://www.collus.com/cos/Transmission System Code.pdf

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 for providing the Customer with a copy of this document.

1.5 Contact Information

The Distributor and its agents can be contacted during normal working hours (Monday to Friday between 8:30 and 4:30). Please refer to the Contact Listing in the Appendices for the 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 a mediator. The mediator shall be acceptable to both parties and have knowledge and experience in the matter under dispute, or professional qualifications, or experience in alternative dispute resolution, or both. The parties shall thereafter participate in mediation with the mediator through such process as the mediator, in consultation with the parties, may determine.

- None of the parties shall be deemed to be in default of any matter being mediated, until effective or after the date mediation fails.

Referral to Dispute Resolution

Any dispute that is not resolved through mediation as described above shall be referred to a third party dispute resolution agency according to the following procedure:

- Upon the written demand of either of the parties, the dispute shall be referred to an independent third party disputes resolution agency that has been approved by the Board.

- An independent, third party, disputes resolution agency that has been approved by the Board, shall be selected within ten days of the receipt of the demand by the other party.

- The third party disputes resolution agency selected to hear the dispute shall be qualified by education and training to pass on the particular question in dispute.

- The third party disputes resolution agency selected shall immediately proceed to hear the matter or matters in dispute. The decision of the third party disputes resolution agency shall be made within 45 days of the selection, subject to any reasonable delay due to unforeseen circumstances. Notwithstanding the foregoing, if the third party disputes resolution agency fails to make a decision within 60 days of the selection, then either party may elect to have another third party disputes resolution agency hear the matter or matters as if none had previously heard the matter or matters.

- The decision of the third party disputes resolution agency shall be in writing and signed by the agency. It shall be final and binding upon all the parties hereto as to any matter or matters so submitted to the third party disputes resolution agency and shall observe and implement the terms and conditions thereof.

- The compensation and expenses of the third party disputes resolution agency, (unless otherwise determined by the agency) shall be paid equally by the parties.

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. A building 'lies along" a distribution line if it 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.

A Building that 'lies along' a distribution line may be refused connection to that line should the distribution line not have sufficient capacity for the requested connection.

A Building that 'lies along" a distribution line may be refused connection to that line should the connection be bad or unsafe for the system.

2.1.2 Expansions / Offer to Connect

Under the terms of the Distribution System Code Section 3.1, a Distributor has the Obligation to make an Offer to Connect any Building that 'lies along" its distribution system yet may be excluded due to being outside of the Service Territory, or falls outside of the criteria outlined in the Distributors' Conditions of Service. 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.

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.

2.1.3 Connection Denial

The Distribution System Code in section 3.1 sets outs 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
- Any other conditions documented in the distributors Conditions of Service document that are consistent with the conditions identified above and with the goals delineated in the Energy Competition Act, 1998.

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 re-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.

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 - Connection to the electrical distribution system will be provided upon completion of a signed contract between the customer and the distributor, and receipt of approval by the Electrical Safety Authority.

All customers will be required to complete and sign the standard form of contract to apply for the supply of an electrical energy 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:

- *Overdue amounts payable to the Distributor, Retailer, or Wholesaler (provided the Distributor provides the Customer with reasonable notice of the proposed shut off of electricity).*
- *Hazardous conditions.*
- *Electrical disturbance propagation caused by Customer equipment that is not corrected in*

a timely fashion.

- *Energy diversion, fraud or abuse on the part of the Customer.*
- *When ordered to do so by any authority having the legal right to issue such an order.*
- *Adverse effect on the reliability and safety of the distribution system.*
- *Imposition of an unsafe worker situation beyond normal risks inherent in the operation of the distribution system.*
- *A material decrease in the efficiency of the distributor's distribution system.*
- *A materially adverse effect on the quality of distribution services received by an existing connection.*
- *Inability of the distributor to perform planned inspections and maintenance.*
- *Failure of the consumer or customer to comply with a directive of a distributor that the distributor makes for purposes of meeting its licence obligations.*

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 higher degree of security than that of normal supply 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*

An electrical requirement in excess of 300 kVA may require a customer owned Substation supplied at the voltage as determined by the distributor.

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 http://www.esainspection.net/code.html and in particular, shall ensure that customer emergency generation does not back-feed on the Distributors' system.

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 / Bulk Metering

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

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 will be considered.

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 exists, the meters shall be grouped where practicable.

The customer/contractor 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/contractor shall insure that all service identifications are accurate and by not doing so will be held totally 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.

2.3.7.1.5 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 remove the lock and energize it without first receiving approval from the Distributor.

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.

2.3.7.2 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 over a telephone line. To accommodate this feature the Owner will provide shared access to a telephone line 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, the Distributor may require the phone line to be dedicated for metering purposes only.

- 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.
- Phone lines must be installed and functioning prior to the new service being energized.

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.

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/cos/measurement erros.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/cos/measurement erros.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 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 metering equipment to be provided 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 Market Operator. http://www.theimo.com/

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 though 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

Where a developer proposes the development of premises that requires the Distributor to place equipment orders for special projects, the developer is required to sign the necessary Supply Agreements and furnish a suitable deposit before such equipment is ordered by the Distributor.

Whenever required by the Distributor, the Customer shall provide and maintain security in an amount that the Distributor has been mandated to collect, or deems necessary and reasonable. The Distributor

shall require security amounts based on the existing security and deposit policies. The current deposit policy shall be provided to the Customer upon request.

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:

Are based on rates approved by the Ontario Energy Board, and fall outside the scope of this document. 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 $2,000 general administration fee may be charged to the parties responsible in addition to all direct costs incurred by the Distributor.

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/cos/privacy_act.doc

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 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:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *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 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.

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:

- **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.

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:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *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 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.

3.2.9 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.

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 etc.

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.

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 arrestors.

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 IMO or OEB registration Requirements, and appropriate Licences.
http://www.collus.com/cos/Generator Application.pdf

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.

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 IMO 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 IMO 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.

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 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 to a customer;

"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 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. This includes developers of residential or commercial sub-divisions;

"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, for which a charge or rate has been approved by the Board under section 78 of the *Act*.

"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 Generator" or **"Embedded Generation Facility"** means a generator whose generation facility is not directly connected to the IMO-controlled grid but instead is connected to a distribution system;

"Embedded Market Participant" means a consumer who is a wholesale market participant whose facility is not directly connected to the IMO-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" 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;

"IMO" means the Independent Electricity Market Operator established under the Electricity Act;

"IMO-Controlled Grid" means the transmission systems with respect to which, pursuant to agreements, the IMO has authority to direct operation;

"Interval meter" means a meter that measures and records electricity use on an hourly or sub-hourly basis;

"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 Ac*t;

"Measurement Canada" means the Special Operating Agency established in August 1996 by the *Electricity and Gas Inspection Ac*t, 1980-81-82-83, c. 87., and Electricity and Gas Inspection Regulations (SOR/86-131);

"Meter Service Provider" means any entity that performs metering services on behalf of a distributor;

"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;

***"Ontario Energy Board Ac*t"** means the *Ontario Energy Board Act, 199*8, 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 generator, means the connection point where electricity produced by the generator 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;

"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 IMO-administered markets;

SECTION 5 APPENDICIES

Electrical Planning Requirements Document

Electric Service Meter Base/ Service Verification Form

Contact Information

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Cornerstone Hydro Electric Concepts Association Inc.

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: _____ **Date:** _____

(Representative of Applicant)

Name: _____ **Title:** _____

Cornerstone Hydro Electric Concepts Association Inc.

Electric Service Meter Base/ Billing Address Verification Form

This form **must** be completed by the Owner and/or their Electrical Contractor if applicable prior to service connection.

Electric Service Municipal Address: _____

Name of Owner: _____

Telephone: ( ) _____ **Fax:** ( ) _____

Name of Contractor: _____

Telephone: ( ) _____ **Fax:** ( ) _____

In area (A) provided below, carefully sketch the Front View layout of the Electric Meter Base(s). Match the corresponding (B) BILLING ADDRESS for each meter base(s) shown in (A).

(A) FRONT VIEW OF ELECTRIC METER BASE(S)	(B) BILLING ADDRESS
	1)
	2)
	3)
	4)
	5)
	6)
	5)
	7)
	8)
	9)
	10)
	11)

I/We the undersigned, acknowledge the information provided above has been verified and is accurate.

Signature of Owner: _____ **Date:** _____

Signature of Contractor: _____ **Date:** _____

Contact Information

Local Distribution Company	Contact Phone Number
Centre Wellington Hydro Ltd. Licence # ED-1999-0269	Phone: (519) 843-2900
COLLUS Power Corp. Licence # ED-1999-0125	Phone: (705) 445-1800
Erie Thames Powerlines Corp. Licence # ED-1999-0287	Phone: (519) 773-2931 After Hours 1-877-850-3128
Grand Valley Energy Inc. Licence # ED-1999-0045	Phone: (519) 928-3112
Gravenhurst Hydro Electric Inc. Licence # ED-1999-0277	Phone: (705) 687-2321
Innisfil Hydro Distribution Systems Ltd. Licence # ED-1999-0158	Phone: (705) 431-6870
Lakefront Utilities Inc. Licence # ED-1999-0180	Phone: (905) 372-2193
Lakeland Power Distribution Ltd. Licence # ED-1999-0047	Phone: (705) 789-5442
Midland Power Utility Corporation Licence # ED-1999-0258	Phone: (705) 526-9361
North Bay Hydro Distribution Ltd. Licence # ED-1999-0107	Phone: (705) 474-8100
Orangeville Hydro Ltd. Licence # ED-2002-0500	Phone: (519) 942-8000
Orillia Power Licence # ED-1999-0084	Phone: (705) 326-2495
Parry Sound Power Corporation Licence # ED-1999-0219	Phone: (705) 746-5866
Rideau St. Lawrence Distribution Inc. Licence # ED-1999-0151	Phone: (613) 925-3851
Wasaga Distribution Inc. Licence # ED-1999-0086	Phone: (705) 429-2517
Wellington North Power Inc. Licence # ED-1999-0295	Phone: (519) 323-1710
Westario Power Inc. Licence # ED-1999-0174	Phone: (519) 396-3471 Toll Free: 1-866-978-2746
West Coast Huron Energy Inc. Licence # ED-1999-0289	Phone: (519) 524-7371
Woodstock Hydro Services Inc. Licence # ED-1999-0164	Phone: (519) 537-3488

Note: Licence Numbers published by OEB as of May 1, 2003

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Changes in Conditions of Services

The Applicant is a member of the CHEC group and plans to review and make changes to the Conditions of Service appropriately with the group's Operations Committee. The new Conditions of Service will be developed in accordance with the Distribution System Code and Guidelines set out by the Ontario Energy Board to reflect any recent changes.

List of Witnesses and their Curriculum Vitae

The Applicant will be pleased to provide a list of witnesses and their curriculum vitae upon request or if an oral hearing is required

Budget Directives (Capital and Operating)

The Applicant compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budgets. This budget information is compiled for both the Bridge and Test Years.

Revenue Forecast

The energy sales and revenue forecast model was updated to reflect more recent information. This model was then used to prepare the revenue, throughput volume and revenue forecast at existing rates for fiscal 2008 and 2009. The forecast is weather normalized as outlined in Exhibit 3; Tab 2; Schedule 1 and considers such factors as new customer additions and load profiles for all classes of customers.

Operating and Maintenance Expense Forecast

The operating and maintenance expenses for fiscal 2008 Bridge Year and 2009 Test Year have been forecasted using a zero based methodology and is strongly influenced by prior year experience. Each item is reviewed by account for each of the forecasted years.

Capital Budget

The capital budget process begins with a review of all the accounts and the previous year's work. All capital expenditures are budgeted on a line by line and/or project basis based on need and forecasted customer growth.

The Applicant continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service area. The increase is attributed to the need to replace existing aging infrastructure in order to maintain safe and reliable delivery of electricity to our customers.

Changes in Methodology

The Applicant is not requesting any changes in methodology in the current proceeding.

Finance

Financial Statements (2006)

Financial Statements of

CENTRE WELLINGTON HYDRO LTD.

Year ended December 31, 2006

KPMG LLP
Chartered Accountants
115 King Street South
2nd Floor
Waterloo ON N2J 5A3

Telephone (519) 747-8800
Fax (519) 747-8830
Internet www.kpmg.ca

AUDITORS' REPORT

To the shareholder of Centre Wellington Hydro Ltd.

We have audited the balance sheet of Centre Wellington Hydro Ltd. 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.

KPMG LLP

Chartered Accountants

Waterloo, Canada

March 23, 2007

KPMG LLP, is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International, a Swiss cooperative.

CENTRE WELLINGTON HYDRO LTD.

Balance Sheet

December 31, 2006, with comparative figures for 2005

	2006	2005
Assets		
Current assets:		
Cash	$ 5,394,952	$ 5,233,813
Accounts receivable	2,006,684	926,307
Unbilled revenue	1,110,773	1,629,934
Income taxes recoverable	106,875	-
Inventory	181,991	176,204
Prepaid expenses	34,166	42,347
	8,835,441	8,008,605
Property, plant and equipment (note 3)	7,086,954	6,990,470
Long-term investment	1	1
Regulatory assets, net (note 8)	-	302,794
	$ 15,922,396	$ 15,301,870
Liabilities and Shareholder's Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 2,934,882	$ 2,184,908
Current portion of customer deposits	209,896	236,919
Income taxes payable	-	109,124
Due to shareholder	-	300,445
	3,144,778	2,831,396
Note payable (note 4)	5,046,753	5,046,753
Post-employment benefits (note 9)	84,988	84,773
Regulatory liabilities, net (note 8)	154,666	-
Shareholder's equity:		
Share capital (note 5)	5,035,066	5,035,066
Retained earnings	2,456,145	2,303,882
	7,491,211	7,338,948
Commitments (note 11)		
	$ 15,922,396	$ 15,301,870

See accompanying notes to financial statements.

On behalf of the Board:

_____ Director _____ Director

CENTRE WELLINGTON HYDRO LTD.

Statement of Earnings and Retained Earnings

Year ended December 31, 2006, with comparative figures for 2005

	2006	2005
Sales	$ 11,397,649	$ 13,575,859
Cost of sales	8,974,004	11,122,082
	2,423,645	2,453,777
Other	165,571	160,100
Investment income	261,418	367,250
	2,850,634	2,981,127
Expenses:		
Amortization	488,770	447,230
General and administrative	728,098	780,718
Billing and collecting	328,595	261,470
Interest on promissory note	389,494	377,895
Operating and maintenance	516,598	524,826
	2,451,555	2,392,139
Earnings before income taxes	399,079	588,988
Income taxes (note 7)	246,816	175,000
Net earnings	152,263	413,988
Retained earnings, beginning of year	2,303,882	1,889,894
Retained earnings, end of year	$ 2,456,145	$ 2,303,882

See accompanying notes to financial statements.

CENTRE WELLINGTON HYDRO LTD.

Statement of Cash Flows

Year ended December 31, 2006, with comparative figures for 2005

	2006	2005
Cash provided by (used in):		
Operations:		
Net earnings	$ 152,263	$ 413,988
Items not involving cash:		
Amortization of property, plant and equipment	549,664	495,347
Increase in post employment benefits	215	84,773
Decrease (increase) in accounts receivable	(1,080,377)	109,585
Decrease (increase) in unbilled revenue	519,161	(341,262)
Increase in income taxes recoverable	(106,875)	-
Decrease (increase) in inventory	(5,787)	30,682
Decrease in prepaid expenses	8,181	11,391
Increase in accounts payable and accrued liabilities	749,974	564,407
Increase (decrease) in current portion of customer deposits	(27,023)	114,415
Increase (decrease) in income taxes payable	(109,124)	66,021
Decrease in regulatory assets	457,460	188,479
	1,107,732	1,737,826
Financing:		
Decrease in amounts due to shareholder	(300,445)	(107,847)
Investments:		
Addition to property, plant and equipment	(646,148)	(404,055)
Increase in cash	161,139	1,225,924
Cash, beginning of year	5,233,813	4,007,889
Cash, end of year	$ 5,394,952	$ 5,233,813
Supplemental cash flow information:		
Payments in lieu of corporate income taxes paid	$ 484,746	$ 52,205
Interest on long-term debt	389,494	365,890

See accompanying notes to financial statements.

1. Significant accounting policies:

(a) Basis of presentation:

These financial statements have been prepared on the basis of accounting principles for electrical utilities in Ontario as required by Ontario Energy Board ("OEB") under the authority of Section 52, 70(2) and (78) of the Ontario Energy Board Act, 1998, and reflect the policies as set forth in the "Accounting Procedures Handbook for Electric Distribution Utilities" ("AP"). All principles employed are in accordance with Canadian generally accepted accounting principles.

(b) Use of estimates:

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates.

(c) Financial instruments:

The Company's financial instruments consist of cash, accounts receivable, unbilled revenue, accounts payable and accrued liabilities, customer deposits and note payable. Management's opinion is that they are not exposed to significant interest, currency or credit risks arising from these financial instruments.

(d) Inventory:

Inventory is valued at the lower of cost and market value, where cost is generally determined on the average cost basis and market value determined at net realizable value.

(e) Employee future benefits:

Employee future benefits are recorded on an accrual basis. The accrued benefit obligations and current service cost are calculated using the projected benefits method pro-rated on service and based on assumptions that reflect management's best estimate. The current service cost for a period is equal to the actuarial present value of benefits attributed to employee's services rendered in the period. Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. Actuarial gains (losses) are expensed during the period in which the gains (losses) become known.

1. Significant accounting policies (continued):

(f) Property, plant and equipment:

Property, plant and equipment are recorded at cost. Property, plant and equipment are amortized on a straight-line basis using the following rates:

Land and land rights	0-50 years
Buildings	40-50 years
Distribution Equipment	15-30 years
Vehicles	5-8 years
Other tools and equipment	5-15 years
Computer equipment	3-5 years

(g) Pensions:

Pension costs for current service are charged to earnings on a current basis.

(h) Revenue:

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

(i) Contributions in aid of construction:

Capital contributions are required contributions received from outside sources used to finance additions to capital assets. Capital contributions received are treated as a "credit" contra account included in the determination of capital assets. The amount is subsequently amortized by a charge to accumulated amortization and a credit to amortization expense, at an equivalent rate to that used for the amortization of the related capital assets.

(j) Rate setting:

On December 9, 2002, the Province of Ontario enacted the Electricity Pricing, Conservation and Supply Act, 2002 ("Bill 210"), which amended the Electricity Act, 1998 and other various statutes. This Bill was enacted for the purpose of implementing the Electricity Action Plan announced by the Premier of Ontario on November 11, 2002. A summary of the significant provisions of Bill 210 are as follows:

1. Significant accounting policies (continued):

(j) Rate setting (continued):

Energy prices for low volume and designated consumers (as defined in Bill 210) were fixed at 4.3 cents per kWh, retroactive to May 1, 2002. Most of the Company's distribution customers qualify for the fixed energy price. In recognition of the amounts paid in excess of 4.3 cents per kWh for the period from May 1, 2002 to December 1, 2002, Bill 210 required distributors to issue a $75 refund to eligible consumers and to credit any remaining refund on future bills.

Effective December 1, 2002, the price paid by distributors to the Independent Electricity Systems Operator for wholesale market charges other than energy is fixed at the same price distributors are permitted to charge their customers. For the period of May 1, 2002 to December 1, 2004, the difference between the rates paid by distributors and the rates paid by customers were accumulated in retail variance accounts under the provisions of Article 490 in the OEB's Accounting Procedures Handbook. These variances commenced recovery by rate adjustments in 2006.

Regulatory assets represent costs that have been deferred because it is probable that they will be recovered in future rates. Regulatory assets recognized at December 31, 2006 are disclosed in note 8. The Company continually assesses the likelihood of recovery of regulatory assets. If recovery through future rates was no longer considered probable, the amounts would be charged to the results of operations in the period that the assessment was made.

Effective April 1, 2005, the fixed energy charges increased from 4.3 cents per kWh to 4.7 cents per kWh for the first 750 kWh and 5.5 cents for the remainder used by low volume and designated customers. As the Company is a distribution company, it increased the distribution rates effective April 1, 2005 for approximately 25% of the regulatory assets recorded at December 31, 2002. The total regulatory assets at December 31, 2002 are to be collected over a 4 year period commencing March 1, 2005, with the rates adjusted for an 11 month period in the first year of collection. Amounts charged to customers commencing April 1, 2005 will reduce the regulatory assets.

On December 9, 2004, the OEB released its process for OEB review of the prudence of the total regulatory asset amounts claimed by electricity distributors. During 2006, the OEB granted approval for the final recovery of these costs through distribution rates through to April 30, 2008.

1. Significant accounting policies (continued):

(k) Regulatory assets:

The principal regulatory assets of the Company are comprised of transition costs, a pre-market opening electricity variance and settlement variances, and other costs.

(i) Transition costs are costs incurred to align systems and practices with the requirements of the future competitive electricity market in Ontario in accordance with the Energy Competition Act, 1998. They have been deferred in accordance with the criteria set out in the OEB's Electricity Distribution Rate Handbook and the AP Handbook. Under such regulation, certain costs are allowed to be deferred that would be expensed when incurred under GAAP for unregulated businesses.

(ii) Pre-Market Opening Electricity Variance for the period January 1, 2001 to April 30, 2002, the date of market opening, has been recognized in accordance with the AP Handbook. The pre-market opening variance represents the difference between the utility's cost of power purchased based upon time-of-use ("TOU") rates and the amounts billed for the cost of power to non-TOU customers at an average rate for the same period.

Settlement variances for the period May 1, 2002 to December 31, 2006 have been recognized in accordance with criteria set out in the AP Handbook. The settlement variances relate primarily to service charges, non-competitive electricity charges and imported power charges. The nature of the settlement variances is such that the balance will fluctuate between assets and liabilities from year to year and are reported at period end dates in accordance the rules prescribed by the OEB.

(iii) Conservation and demand management ("CDM") program costs incurred in 2005 and 2006 have been deferred pursuant to the OEB's Procedural Order No. 1 and the AP Handbook. Effective for 2005 and subsequent years, a CDM contra asset account has been established in accordance with the OEB's AP Handbook, which effectively reverts the original entries and recognizes CDM related expenses and CDM related capital assets incurred by the Company, in accordance with GAAP.

1. Significant accounting policies (continued):

(k) Regulatory assets (continued):

(iv) Cash OMERS pension costs of $47,320 incurred by the Company beginning in 2005, have been deferred in accordance with the OEB's letter of direction of February 15, 2005 to all local electricity distribution companies. These costs are being recovered in rates commencing in 2006. To the extent that OMERS pension costs have been incurred, which do not qualify for deferral, these costs have been expensed during the period they were incurred. The deferral of the costs is permitted as the Company qualifies under GAAP as a rate regulated entity. If rate regulation accounting were not applied, these costs would have been recorded as expenses in 2005.

(l) Payments in lieu of corporate income taxes:

The Company provides for payments in lieu of corporate income taxes relating to its regulated business using the taxes payable method as permitted by the Canadian Institute of Chartered Accountants (CICA) and the OEB.

The Company is generally exempt from tax under the Income Tax Act (Canada), if not less than 90% of its capital is owned by the Township of Centre Wellington and not more than 10% of its income is derived from activities carried on outside the municipal boundaries of the Township. A corporation exempt under the Income Tax Act (Canada) is also generally exempt from tax under the Corporations Tax Act.

The Company is a municipal electric utility (MEU) for purposes of the payments in lieu of taxes ("PIL") regime contained in the Electricity Act, 1998. This Act provides that a MEU that is exempt from tax under the Income Tax Act (Canada) and the Corporations Tax Act is required to make, for each taxation year, a payment in lieu of taxes to the Ontario Electricity Financial Corporation in an amount approximating the tax that it would be liable to pay if it were not exempt from tax.

The OEB's Electricity Distribution Rate Handbook provides for the recovery of PILs through annual distribution rate adjustments as permitted by the OEB.

1. Significant accounting policies (continued):

(l) Payments in lieu of corporate incomes taxes (continued):

The PILs regime came into effect on October 1, 2001 at which time the Company was deemed to have commenced a new taxation year for purpose of determining its liability for PILs. Accordingly, the Company was deemed to have disposed of its assets at their then fair market value and to have reacquired such assets at that same amount. The differences between the financial statement carrying value and the tax bases of assets and liabilities were accounted for using the taxes payable method, in accordance with recommendations of the CICA and the OEB.

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

2. Incorporation:

The Company was incorporated by Articles of Incorporation of August 22, 2000. This incorporation was required in accordance with the provincial government's Electricity Act, 1998. It commenced normal operations on November 1, 2000 when the assets of The Township of Centre Wellington Hydro Electric Commission were transferred to the Company by The Corporation of the Township of Centre Wellington.

The book value of the assets transferred at November 1, 2000 was $10,081,818. As consideration for the assets acquired, the Company issued 1,000 common shares valued at $5,035,066 and a promissory note in the amount of $5,046,752 to the Corporation of The Township of Centre Wellington.

3. Property, plant and equipment:

	Cost	Accumulated amortization	2006 Net book value	2005 Net book value
Land and land rights	$ 82,014	$ 2,991	$ 79,023	$ 78,054
Buildings	1,022,541	192,387	830,154	852,032
Distribution Equipment	12,433,316	5,903,707	6,529,609	6,492,278
Vehicles	969,980	533,899	436,081	204,125
Other tools and equipment	524,620	329,837	194,783	219,829
Computer equipment	235,656	210,886	24,770	13,072
Contributed capital	(1,174,167)	(166,701)	(1,007,466)	(868,920)
	$ 14,093,960	$ 7,007,006	$ 7,086,954	$ 6,990,470

During the year, capital assets were acquired at an aggregate cost of $828,032 (2005 - $591,475). Of this total, $181,884 (2005 - $187,421) were acquired by means of contributed capital, with the remaining $646,148 (2005 - $404,055) paid in cash.

4. Note Payable:

	2006	2005
Demand promissory note payable to the Corporation of The Township of Centre Wellington, bearing interest 7.25%	$ 5,046,753	$ 5,046,753

5. Share capital:

	2006	2005
Authorized:		
Unlimited number of common shares		
Issued:		
1,100 Common shares	$ 5,035,066	$ 5,035,066

6. Related party transactions:

The Company provides water and sewage billing and collection services to the customers of the former Town of Fergus and the Village of Elora, as well as supplying streetlighting energy and streetlighting maintenance services to the former Town of Fergus and Village of Elora.

Revenue includes $143,735 (2005 - $218,318) from the Township. These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

7. Income taxes:

Corporate income tax expense differs from the amount that would be computed by applying the federal and provincial statutory tax rates of 36.12% (2005 - 36.12%) to earnings before income taxes. The reasons for the differences and related tax effects are as follows:

	2006	2005
Income from operations	$ 399,079	$ 588,988
Expected income tax expense	144,150	212,742
Small business deduction and general rate reduction	(39,950)	(77,990)
Capital cost allowance in excess of amortization	(57,920)	(65,742)
Tax effect of timing differences	99,470	126,809
Permanent differences	1,250	(22,175)
Other	-	1,356
Effect of adjustments to prior year actual tax filing	99,816	-
Income tax expense	$ 246,816	$ 175,000

7. Income taxes (continued):

Under the taxes payable method, no adjustments are made for differences between the financial statement carrying values and the tax basis of assets and liabilities. Accordingly, future income tax assets have not been recorded for tax deductions in excess of accounting deductions in the amount of $4,200,000 (2005 - $3,940,745).

As prescribed by a regulatory rate order, income tax expense is recovered through customer rates based on the taxes payable method. Therefore, rates do not include the recovery of future income taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. The Company has not recognized future income taxes, as it is expected that when these amounts become payable, they will be recovered through future rate revenues. Generally accepted accounting principles require the recognition of future income tax liabilities and future tax assets in the absence of rate regulation.

8. Regulatory assets (liabilities), net:

	2006	2005
Transition costs	$ -	$ 35,849
Pre-market opening energy variance	-	723,438
Settlement variances	(414,664)	(169,696)
Regulatory assets recovered	259,998	(286,797)
	$ (154,666)	$ 302,794

9. Post-employment benefits:

Employee future benefits provided by the Company include medical and life insurance benefits. These plans provide benefits to certain employees when they are no longer providing active service. Employee future benefit expense is recognized in the period in which the employees render the services.

The Company pays certain health, dental and life insurance benefits on behalf of its retired employees.

9. Post-employment benefits (continued):

The significant actuarial assumptions adopted in measuring the accrued benefit obligation are as follows:

	2005
Discount rate	5.0%
Dental costs increase	5.0%
Medical costs increase	12.0% in 2005, declining to 5.0% in 2012

Information about the Company's defined benefit plan is as follows:

	2006	2005
Accrued pension benefit:		
Balance, beginning of year	$ 84,773	$ 86,538
Benefit cost for the year	5,570	5,540
Benefits paid for the year	(5,355)	(7,305)
Project accrued benefit obligation at December 31, as determined by actuarial valuation	$ 84,988	$ 84,773

10. Long-term investment:

The Company received demutualization shares of a Canadian life insurance company. The shares have no fixed maturity date and are generally not exposed to interest rate risk.

11. Commitments:

Bank letters of credit have been issued to provide security for the Company's liability for power purchase from the Independent Electricity System Operator ("IESO"). These letters of credit will be drawn upon if the Company is in default of payment of its obligation to the IESO. The maximum potential payment is the face value of the bank letters of credit. At December 31, 2006 the letters of credit outstanding totalled $975,000 (2005 - $975,000).

Financial Statements (2007)

Financial Statements of

CENTRE WELLINGTON HYDRO LTD.

Year ended December 31, 2007

KPMG LLP
Chartered Accountants
115 King Street South
2nd Floor
Waterloo ON N2J 5A3

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Internet www.kpmg.ca

AUDITORS' REPORT

To the shareholder of Centre Wellington Hydro Ltd.

We have audited the balance sheet of Centre Wellington Hydro Ltd. as at December 31, 2007 and the statements of earnings and retained earnings, comprehensive income 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.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Waterloo, Canada
March 14, 2008

KPMG LLP, is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International, a Swiss cooperative. KPMG Canada provides services to KPMG LLP.

CENTRE WELLINGTON HYDRO LTD.

Balance Sheet

December 31, 2007, with comparative figures for 2006

	2007	2006
Assets		
Current assets:		
Cash	$ 6,474,904	$ 5,394,952
Accounts receivable	1,875,121	2,006,684
Unbilled revenue	1,269,263	1,110,773
Income taxes recoverable	-	106,875
Inventory	208,041	181,991
Prepaid expenses	35,015	34,166
	9,862,344	8,835,441
Property, plant and equipment (note 3)	6,961,518	7,086,953
Long-term investment	37,268	1
	$ 16,861,130	$ 15,922,395
Liabilities and Shareholder's Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 2,584,331	$ 2,934,886
Current portion of customer deposits	215,289	209,896
Income taxes payable	288,381	-
	3,088,001	3,144,782
Note payable (note 4)	5,046,753	5,046,753
Post employment benefits (note 9)	84,853	84,988
Regulatory liabilities, net (note 8)	1,052,160	154,666
Shareholder's equity:		
Share capital (note 5)	5,035,066	5,035,066
Retained earnings	2,517,030	2,456,140
Accumulated other comprehensive income	37,267	-
	2,554,297	2,456,140
	7,589,363	7,491,206
Commitments (note 11)		
	$ 16,861,130	$ 15,922,395

See accompanying notes to financial statements.

On behalf of the Board:

_____ Director_ Director

CENTRE WELLINGTON HYDRO LTD.

Statement of Earnings and Retained Earnings

Year ended December 31, 2007, with comparative figures for 2006

	2007	2006
Sales	$ 12,728,214	$ 11,397,649
Cost of sales	10,282,924	8,974,004
	2,445,290	2,423,645
Other	247,803	165,571
Investment income	263,280	261,418
	2,956,373	2,850,634
Expenses:		
Amortization	511,313	488,770
General and administrative	676,376	728,098
Billing and collecting	314,401	328,595
Interest on promissory note	389,567	389,494
Operating and maintenance	551,999	516,598
	2,443,656	2,451,555
Earnings before income taxes	512,717	399,079
Income taxes (note 7)	451,827	246,816
Net earnings	60,890	152,263
Retained earnings, beginning of year	2,456,140	2,303,877
Retained earnings, end of year	$ 2,517,030	$ 2,456,140

See accompanying notes to financial statements.

CENTRE WELLINGTON HYDRO LTD.

Statement of Comprehensive Income

Year ended December 31, 2007, with comparative figures for 2006

		2007		2006
Net earnings	$	60,890	$	152,263
Other comprehensive income (note 1(b)):				
Unrealized gain on available-for-sale financial assets		4,354		-
	$	65,244	$	152,263

See accompanying notes to financial statements.

CENTRE WELLINGTON HYDRO LTD.

Statement of Cash Flows

Year ended December 31, 2007, with comparative figures for 2006

	2007	2006
Cash provided by (used in):		
Operations:		
Net earnings	$ 60,890	$ 152,263
Items not involving cash:		
Amortization of property, plant and equipment	589,402	549,664
Gain on disposal of property, plant and equipment	(38,386)	-
Change in non-cash operating working capital:		
Increase (decrease) in post employment benefits	(135)	215
Decrease (increase) in accounts receivable	131,563	(1,080,377)
Decrease (increase) in unbilled revenue	(158,490)	519,161
Decrease (increase) in income taxes recoverable	106,875	(106,875)
Increase in inventory	(26,050)	(5,787)
Decrease (increase) in prepaid expenses	(849)	8,181
Increase (decrease) in accounts payable and accrued liabilities	(350,555)	449,529
Increase (decrease) in current portion of customer deposits	5,393	(27,023)
Increase (decrease) in income taxes payable	288,381	(109,124)
Increase in regulatory liabilities	897,494	457,460
	1,505,533	807,287
Investments:		
Proceeds from disposal of property, plant and equipment	38,386	-
Addition to property, plant and equipment	(463,967)	(646,148)
	(425,581)	(646,148)
Increase in cash	1,079,952	161,139
Cash, beginning of year	5,394,952	5,233,813
Cash, end of year	$ 6,474,904	$ 5,394,952
Supplemental cash flow information:		
Payments in lieu of corporate income taxes paid	$ 56,570	$ 484,746
Interest on long-term debt	389,567	389,494

See accompanying notes to financial statements.

1. Significant accounting policies:

(a) Basis of presentation:

These financial statements have been prepared on the basis of accounting principles for electrical utilities in Ontario as required by Ontario Energy Board ("OEB") under the authority of Section 52, 70(2) and (78) of the Ontario Energy Board Act, 1998, and reflect the policies as set forth in the "Accounting Procedures Handbook for Electric Distribution Utilities" ("AP"). All principles employed are in accordance with Canadian generally accepted accounting principles.

(b) Financial instruments:

Effective January 1, 2007 the Company adopted CICA Handbook Sections 3855 "Financial Instruments – Recognition and Measurement", 3861 – "Financial Instruments – Disclosure and Presentation", and 1530 – "Comprehensive Income". These new Handbook sections have lead to changes in the accounting for financial instruments.

(i) Financial Instruments – Recognition and Measurement:

As of January 1, 2007, the Company has elected the following balance sheet classifications with respect to its financial assets and financial liabilities:

- Cash is classified as "Assets Held-for-Trading" and is measured at fair value.

- Accounts receivable are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.

- Accounts payable and accrued liabilities and the long-term debt are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.

The Company owns financial instruments which are "available for sale", but not intended for active trading. In 2007, these financial assets have been recorded at fair value, and the related unrealized gain has been reported as "Comprehensive Income". The impact of the restatement to fair value on the opening balance of these financial instruments has been reflected as an adjustment to accumulated other comprehensive income.

1. Significant accounting policies (continued):

(b) Financial instruments (continued):

(ii) Comprehensive income:

Comprehensive income is comprised of net income for the period plus other revenues, expenses, gains, and losses that are excluded from net income but recognized as changes in equity (net assets). The Company includes the unrealized gains and losses on "available for sale" financial assets as comprehensive income.

(c) Use of estimates:

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates.

(d) Inventory:

Inventory is valued at the lower of cost and market value, where cost is generally determined on the average cost basis and market value determined at net realizable value.

(e) Employee future benefits:

Employee future benefits are recorded on an accrual basis. The accrued benefit obligations and current service cost are calculated using the projected benefits method pro-rated on service and based on assumptions that reflect management's best estimate. The current service cost for a period is equal to the actuarial present value of benefits attributed to employee's services rendered in the period. Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. Actuarial gains (losses) are expensed during the period in which the gains (losses) become known.

1. Significant accounting policies (continued):

(f) Property, plant and equipment:

Property, plant and equipment are recorded at cost. Property, plant and equipment are amortized on a straight-line basis using the following rates:

Land and land rights	0-50 years
Buildings	40-50 years
Distribution equipment	15-30 years
Vehicles	5-8 years
Other tools and equipment	5-15 years
Computer equipment	3-5 years

(g) Pension Plan:

The Company provides a pension plan for its employees through the Ontario Municipal Employees Retirement System ["OMERS"]. OMERS is a multi-employer pension plan, which operates as the Ontario Municipal Employees Retirement Fund [the "Fund"] and provides pensions for employees of Ontario municipalities, local boards, public utilities, and school boards. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund.

Prior to 2005, the Company recognized the expense related to this plan as contributions were made.

From January 2005 to April 2006, cash pension costs incurred by the Company were deferred and recognized as regulatory assets as per OEB direction, which are expected to be recovered in future distribution rates (see note 1(k)(iv).

Commencing May 2006, the Company recognized the expense related to this plan as contributions were made.

(h) Revenue:

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

1. Significant accounting policies (continued):

(i) Contributions in aid of construction:

Capital contributions are required contributions received from outside sources used to finance additions to property, plant and equipment. Capital contributions received are treated as a "credit" contra account included in the determination of property, plant and equipment. The amount is subsequently amortized by a charge to accumulated amortization and a credit to amortization expense, at an equivalent rate to that used for the amortization of the related property, plant and equipment.

(j) Rate setting:

On December 9, 2002, the Province of Ontario enacted the Electricity Pricing, Conservation and Supply Act, 2002 ("Bill 210"), which amended the Electricity Act, 1998 and other various statutes. This Bill was enacted for the purpose of implementing the Electricity Action Plan announced by the Premier of Ontario on November 11, 2002. A summary of the significant provisions of Bill 210 are as follows:

Energy prices for low volume and designated consumers (as defined in Bill 210) were fixed at 4.3 cents per kWh, retroactive to May 1, 2002. Most of the Company's distribution customers qualify for the fixed energy price. In recognition of the amounts paid in excess of 4.3 cents per kWh for the period from May 1, 2002 to December 1, 2002, Bill 210 required distributors to issue a $75 refund to eligible consumers and to credit any remaining refund on future bills.

Effective December 1, 2002, the price paid by distributors to the Independent Electricity Systems Operator for wholesale market charges, other than energy, is fixed at the same price distributors are permitted to charge their customers. For the period of May 1, 2002 to December 1, 2004, the difference between the rates paid by distributors and the rates paid by customers, were accumulated in retail variance accounts under the provisions of Article 490 in the OEB's Accounting Procedures Handbook. These variances commenced recovery by rate adjustments in 2006.

Regulatory assets represent costs that have been deferred because it is probable that they will be recovered in future rates. Regulatory assets recognized at December 31, 2006 are disclosed in note 8. The Company continually assesses the likelihood of recovery of regulatory assets. If recovery through future rates was no longer considered probable, the amounts would be charged to the results of operations in the period that the assessment was made.

1. Significant accounting policies (continued):

(j) Rate setting (continued):

Effective April 1, 2005, the fixed energy charges increased from 4.3 cents per kWh to 4.7 cents per kWh for the first 750 kWh and 5.5 cents for the remainder used by low volume and designated customers. As the Company is a distribution company, it increased the distribution rates effective April 1, 2005 for approximately 25% of the regulatory assets recorded at December 31, 2002. The total regulatory assets at December 31, 2002 are to be collected over a 4 year period commencing March 1, 2005, with the rates adjusted for an 11 month period in the first year of collection. Amounts charged to customers commencing April 1, 2005 will reduce the regulatory assets.

On December 9, 2004, the OEB released its process for OEB review of the prudence of the total regulatory asset amounts claimed by electricity distributors. During 2006, the OEB granted approval for the final recovery of these costs through distribution rates through to April 30, 2008.

(k) Regulatory assets:

The principal regulatory assets of the Company are comprised of transition costs, a pre-market opening electricity variance and settlement variances, and other costs.

(i) Transition costs are costs incurred to align systems and practices with the requirements of the future competitive electricity market in Ontario in accordance with the Energy Competition Act, 1998. They have been deferred in accordance with the criteria set out in the OEB's Electricity Distribution Rate Handbook and the AP Handbook. Under such regulation, certain costs are allowed to be deferred that would be expensed when incurred under GAAP for unregulated businesses.

(ii) Pre-Market Opening Electricity Variance for the period January 1, 2001 to April 30, 2002, the date of market opening, has been recognized in accordance with the AP Handbook. The pre-market opening variance represents the difference between the utility's cost of power purchased based upon time-of-use ("TOU") rates and the amounts billed for the cost of power to non-TOU customers at an average rate for the same period.

Settlement variances for the period May 1, 2002 to December 31, 2006 have been recognized in accordance with criteria set out in the AP Handbook. The settlement variances relate primarily to service charges, non-competitive electricity charges and imported power charges. The nature of the settlement variances is such that the balance will fluctuate between assets and liabilities from year to year and are reported at period end dates in accordance with the rules prescribed by the OEB.

1. Significant accounting policies (continued):

(k) Regulatory assets (continued):

(iii) Conservation and demand management ("CDM") program costs incurred in 2005 and 2006 have been deferred pursuant to the OEB's Procedural Order No. 1 and the AP Handbook. Effective for 2005 and subsequent years, a CDM contra asset account has been established in accordance with the OEB's AP Handbook, which effectively reverts the original entries and recognizes CDM related expenses and CDM related capital assets incurred by the Company, in accordance with GAAP.

(iv) Cash OMERS pension costs of $47,320 incurred by the Company beginning in 2005, have been deferred in accordance with the OEB's letter of direction of February 15, 2005 to all local electricity distribution companies. These costs are being recovered in rates commencing in 2006. To the extent that OMERS pension costs have been incurred, which do not qualify for deferral, these costs have been expensed during the period they were incurred. The deferral of the costs is permitted as the Company qualifies under GAAP as a rate regulated entity. If rate regulation accounting were not applied, these costs would have been recorded as expenses in 2005.

(l) Payments in lieu of corporate income taxes:

The Company provides for payments in lieu of corporate income taxes relating to its regulated business using the taxes payable method as permitted by the Canadian Institute of Chartered Accountants (CICA) and the OEB.

The Company is generally exempt from tax under the Income Tax Act (Canada), if not less than 90% of its capital is owned by the Township of Centre Wellington and not more than 10% of its income is derived from activities carried on outside the municipal boundaries of the Township. A corporation exempt under the Income Tax Act (Canada) is also generally exempt from tax under the Corporations Tax Act.

The Company is a municipal electric utility (MEU) for purposes of the payments in lieu of taxes ("PIL") regime contained in the Electricity Act, 1998. This Act provides that a MEU that is exempt from tax under the Income Tax Act (Canada) and the Corporations Tax Act is required to make, for each taxation year, a payment in lieu of taxes to the Ontario Electricity Financial Corporation in an amount approximating the tax that it would be liable to pay if it were not exempt from tax.

The OEB's Electricity Distribution Rate Handbook provides for the recovery of PILs through annual distribution rate adjustments as permitted by the OEB.

3. Property, plant and equipment:

	Cost	Accumulated amortization	2007 Net book value	2006 Net book value
Land and land rights	$ 85,395	$ 3,562	$ 81,833	$ 79,022
Buildings	1,022,541	214,265	808,276	830,154
Distribution equipment	12,732,596	6,744,562	5,988,034	6,529,610
Vehicles	840,271	420,843	419,428	436,081
Other tools and equipment	547,335	-	547,335	194,782
Computer equipment	313,666	236,563	77,103	24,770
Contributed capital	(1,174,167)	(213,676)	(960,491)	(1,007,466)
	$ 14,367,637	$ 7,406,119	$ 6,961,518	$ 7,086,953

During the year, capital assets were acquired at an aggregate cost of $463,967 (2006 - $828,032). Of this total, $nil (2006 - $181,884) were acquired by means of contributed capital, with the remaining $nil (2006 - $646,148) paid in cash.

4. Note payable:

	2007	2006
Demand promissory note payable to the Corporation of The Township of Centre Wellington, bearing interest at 7.25%	$ 5,046,753	$ 5,046,753

5. Share capital:

	2007	2006
Authorized:		
Unlimited number of common shares		
Issued:		
1,100 common shares	$ 5,035,066	$ 5,035,066

6. Related party transactions:

The Company provides water and sewage billing and collection services to the customers of the former Town of Fergus and the Village of Elora, as well as supplying street lighting energy and street lighting maintenance services to the former Town of Fergus and Village of Elora.

Revenue includes $145,901 (2006 - $143,735) from the Township. These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

7. Income taxes:

Corporate income tax expense differs from the amount that would be computed by applying the federal and provincial statutory tax rates of 36.12% (2006 - 36.12%) to earnings before income taxes. The reasons for the differences and related tax effects are as follows:

		2007		2006
Earnings from operations	$	512,717	$	399,079
Expected income tax expense		185,193		144,150
Small business deduction and general rate reduction		(23,998)		(39,950)
Capital cost allowance in excess of amortization		(34,758)		(57,920)
Tax effect of timing differences		324,126		99,470
Permanent differences		1,264		1,250
Effect of adjustments to prior year actual tax filing		-		99,816
Income tax expense	$	451,827	$	246,816

7. Income taxes (continued):

Under the taxes payable method, no adjustments are made for differences between the financial statement carrying values and the tax basis of assets and liabilities. Accordingly, future income tax assets have not been recorded for tax deductions in excess of accounting deductions in the amount of $5,100,000 (2006 - $4,200,000).

As prescribed by a regulatory rate order, income tax expense is recovered through customer rates based on the taxes payable method. Therefore, rates do not include the recovery of future income taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. The Company has not recognized future income taxes, as it is expected that when these amounts become payable, they will be recovered through future rate revenues. Generally accepted accounting principles require the recognition of future income tax liabilities and future tax assets in the absence of rate regulation.

8. Regulatory assets (liabilities), net:

	2007	2006
Settlement variances	$ (1,114,556)	$ (414,664)
Regulatory assets recovered	62,396	259,998
	$ (1,052,160)	$ (154,666)

9. Post employment benefits:

Employee future benefits provided by the Company include medical and life insurance benefits. These plans provide benefits to certain employees when they are no longer providing active service. Employee future benefit expense is recognized in the period in which the employees render the services.

The Company pays certain health, dental and life insurance benefits on behalf of its retired employees.

9. Post employment benefits (continued):

The significant actuarial assumptions adopted in measuring the accrued benefit obligation are as follows:

	2006
Discount rate	5.0%
Dental costs increase	5.0%
Medical costs increase	12.0% in 2005, declining to 5.0% in 2012

Information about the Company's defined benefit plan is as follows:

	2007	2006
Accrued pension benefit:		
Balance, beginning of year	$ 84,988	$ 84,773
Benefit cost for the year	5,643	5,570
Benefits paid for the year	(5,778)	(5,355)
Projected accrued benefit obligation at December 31, as determined by actuarial valuation	$ 84,853	$ 84,988

10. Long-term investment:

The Company received demutualization shares of a Canadian life insurance company. The shares have no fixed maturity date and are generally not exposed to interest rate risk.

11. Commitments:

Bank letters of credit have been issued to provide security for the Company's liability for power purchase from the Independent Electricity System Operator ("IESO"). These letters of credit will be drawn upon if the Company is in default of payment of its obligation to the IESO. The maximum potential payment is the face value of the bank letters of credit. At December 31, 2007, the letters of credit outstanding totalled $975,000 (2006 - $975,000).

Pro Forma Statements (2008 and 2009)

2008 Pro Forma at Existing Rates

Account Grouping	2008
1050-Current Assets	7,493,255
1100-Inventory	205,541
1150-Non-Current Assets	37,368
1200-Other Assets and Deferred Charges	(1,188,622)
1300-Intangible Plant	
1450-Distribution Plant	13,176,759
1500-General Plant	2,773,128
1550-Other Capital Assets	(960,491)
1600-Accumulated Amortization	(8,186,556)
Total Assets	**13,350,382**
1650-Current Liabilities	2,114,823
1700-Non-Current Liabilities	498,544
1800-Long-Term Debt	5,046,753
Total Liabilities	7,660,121
1850-Shareholders' Equity	5,690,261
Total Liabilities & Shareholders' Equity	**13,350,382**
3000-Sales of Electricity	11,335,522
3050-Revenues From Services - Distribution	2,516,418
3100-Other Operating Revenues	145,086
3150-Other Income & Deductions	30,472
3200-Investment Income	152,513
3350-Power Supply Expenses	(11,335,522)
Net Revenues	**2,844,489**
3500-Distribution Expenses - Operation	284,900
3550-Distribution Expenses - Maintenance	296,200
3650-Billing and Collecting	323,100
3700-Community Relations	56,500
3800-Administrative and General Expenses	739,200
3950-Taxes Other Than Income Taxes	33,000
OM&A Expenses	**1,732,900**
3850-Amortization Expense	594,185
Earnings Before Interest & Taxes	**517,404**
3900-Interest Expense	389,568
Earnings Before Tax	**127,836**
4000-Income Taxes	27,037
Net Income excluding Extraordinary Items	**100,799**
4100-Extraordinary & Other Items	
Net Income	**100,799**

2009 Pro Forma at New Rates

Account Grouping	2009
1050-Current Assets	7,501,076
1100-Inventory	205,541
1150-Non-Current Assets	37,368
1200-Other Assets and Deferred Charges	(1,080,264)
1300-Intangible Plant	
1450-Distribution Plant	13,832,359
1500-General Plant	2,933,128
1550-Other Capital Assets	(960,491)
1600-Accumulated Amortization	(8,906,434)
Total Assets	**13,573,750**
1650-Current Liabilities	2,080,605
1700-Non-Current Liabilities	493,701
1800-Long-Term Debt	5,046,753
Total Liabilities	7,621,059
1850-Shareholders' Equity	5,941,224
Total Liabilities & Shareholders' Equity	**13,573,750**
3000-Sales of Electricity	11,369,553
3050-Revenues From Services - Distribution	2,773,510
3100-Other Operating Revenues	145,986
3150-Other Income & Deductions	29,700
3200-Investment Income	86,585
3350-Power Supply Expenses	(11,369,553)
Net Revenues	**3,035,781**
3500-Distribution Expenses - Operation	264,900
3550-Distribution Expenses - Maintenance	292,600
3650-Billing and Collecting	332,200
3700-Community Relations	35,600
3800-Administrative and General Expenses	786,300
3950-Taxes Other Than Income Taxes	35,000
OM&A Expenses	**1,746,600**
3850-Amortization Expense	638,185
Earnings Before Interest & Taxes	**650,996**
3900-Interest Expense	389,568
Earnings Before Tax	**261,429**
4000-Income Taxes	10,466
Net Income excluding Extraordinary Items	**250,963**
4100-Extraordinary & Other Items	
Net Income	**250,963**

Cost of Power Projections

Electricity (Commodity)	2008	rate ($/kWh):	$ 0.0545	2009	rate ($/kWh):	$ 0.0545
Class Name	**Volume (kWh)**		**Amount**	**Volume (kWh)**		**Amount**
Residential	46,649,903		$ 2,542,420	47,172,831		$ 2,570,919
General Service Less Than 50 kW	22,275,984		$ 1,214,041	22,838,459		$ 1,244,696
General Service 50 to 2,999 kW	67,888,959		$ 3,699,948	67,481,331		$ 3,677,733
General Service 3,000 to 4,999 kW	22,337,244		$ 1,217,380	21,969,645		$ 1,197,346
Unmetered Scattered Load	422,879		$ 23,047	419,344		$ 22,854
Sentinel Lighting	48,144		$ 2,624	45,820		$ 2,497
Street Lighting	1,193,747		$ 65,059	1,165,253		$ 63,506
TOTAL			**$ 8,764,519**			**$ 8,779,551**

Transmission - Network		2008	$ -		2009	$ -
Class Name	**Volume (kWh/kW)**	**Rate**	**Amount**	**Volume (kWh/kW)**	**Rate**	**Amount**
Residential	46,649,903	0.00390	$ 181,935	47,172,831	0.00553	$ 261,054
General Service Less Than 50 kW	22,275,984	0.00350	$ 77,966	22,838,459	0.00497	$ 113,416
General Service 50 to 2,999 kW	168,573	1.43270	$ 241,515	166,526	2.03285	$ 338,522
General Service 3,000 to 4,999 kW	44,426	1.60240	$ 71,188	43,874	2.27363	$ 99,753
Unmetered Scattered Load	422,879	0.00350	$ 1,480	419,344	0.00497	$ 2,082
Sentinel Lighting	128	1.08600	$ 139	122	1.54092	$ 188
Street Lighting	3,143	1.08050	$ 3,396	3,066	1.53311	$ 4,701
TOTAL			**$ 577,619**			**$ 819,716**

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Transmission - Connection		**2008**	**$ -**		**2009**	**$ -**
Class Name	**Volume (kWh/kW)**	**Rate**	**Amount**	**Volume (kWh/kW)**	**Rate**	**Amount**
Residential	46,649,903	0.00620	$ 289,229	47,172,831	0.00465	$ 219,306
General Service Less Than 50 kW	22,275,984	0.00550	$ 122,518	22,838,459	0.00412	$ 94,186
General Service 50 to 2,999 kW	168,573	2.20690	$ 372,024	166,526	1.65485	$ 275,575
General Service 3,000 to 4,999 kW	44,426	2.60290	$ 115,636	43,874	1.95179	$ 85,633
Unmetered Scattered Load	422,879	0.00550	$ 2,326	419,344	0.00412	$ 1,729
Sentinel Lighting	128	1.74180	$ 223	122	1.30609	$ 159
Street Lighting	3,143	1.70610	$ 5,363	3,066	1.27932	$ 3,922
TOTAL			**$ 907,319**			**$ 680,511**

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Wholesale Market Service	**2008**	**rate ($/kWh):**	**$ 0.0052000**	**2009**	**rate ($/kWh):**	**$ 0.0052000**
Class Name	**Volume (kWh)**		**Amount**	**Volume (kWh)**		**Amount**
Residential	46,649,903		$ 242,579	47,172,831		$ 245,299
General Service Less Than 50 kW	22,275,984		$ 115,835	22,838,459		$ 118,760
General Service 50 to 2,999 kW	67,888,959		$ 353,023	67,481,331		$ 350,903
General Service 3,000 to 4,999 kW	22,337,244		$ 116,154	21,969,645		$ 114,242
Unmetered Scattered Load	422,879		$ 2,199	419,344		$ 2,181
Sentinel Lighting	48,144		$ 250	45,820		$ 238
Street Lighting	1,193,747		$ 6,207	1,165,253		$ 6,059
TOTAL			**$ 836,248**			**$ 837,682**

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Rural Rate Protection	2008	rate ($/kWh):	$ 0.001	2009	rate ($/kWh):	$ 0.001
Class Name	**Volume (kWh)**		**Amount**	**Volume (kWh)**		**Amount**
Residential	46,649,903		$ 46,650	47,172,831		$ 47,173
General Service Less Than 50 kW	22,275,984		$ 22,276	22,838,459		$ 22,838
General Service 50 to 2,999 kW	67,888,959		$ 67,889	67,481,331		$ 67,481
General Service 3,000 to 4,999 kW	22,337,244		$ 22,337	21,969,645		$ 21,970
Unmetered Scattered Load	422,879		$ 423	419,344		$ 419
Sentinel Lighting	48,144		$ 48	45,820		$ 46
Street Lighting	1,193,747		$ 1,194	1,165,253		$ 1,165
TOTAL			**$ 160,817**			**$ 161,093**
Class Name	**Volume**	**2008**	**Amount**	**Volume**	**2009**	**Amount**
Low Voltage Charges		**89,000**	**$ 89,000.00**		**91,000**	**$ 91,000.00**
GRAND TOTAL			**$ 11,335,522**			**$ 11,369,553**

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Reconciliation between Financial Statements and Financial Results Filed

There is no difference between the audited financial statements and the financial results filed with the Ontario Energy Board.

Proposed Accounting Treatment for long lived assets

The Applicant's accounting procedures are consistent with the Canadian GAAP and the Board's Accounting Procedures Handbook. The Applicant does not capture the cost of funding capital projects (AFUDC) and accordingly, has not reflected any amounts concerning this practice in this rate application. The Applicant will follow the Board's Uniform System of Accounts (USoA) should the need arise using the prescribed interest rate in effect at that time.

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. Gains or losses on disposition of such assets are credited or charged to "Other income" in the Statement of Income.

Compliance with the Uniform System of Accounts

The Applicant has followed the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the USofA in the preparation of this Application.

Accounting Orders

The Applicant is not aware of any accounting orders at this time.

Annual Report

The Applicant does not formally produce an annual report, however, the audited Financial Statements are presented to the Shareholders and approved by them the annual general meeting.

Prospectus, information and recent share issue update

Not Applicable.

Extraordinary Events

The Applicant has not experienced any extraordinary circumstances since the date of incorporation that would adversely affect the utility.

Overview

Rate Base Overview

A projection of the Applicant's rate base is provided for both the Bridge Year (2008) and the Test Year (2009). Comparisons are also provided for the 2006 approved and 2006 actual data and 2007 actual data.

The Applicant's forecast rate base for the test year is $8,818,124. The rate base underlying the test year revenue requirements includes a forecast of net fixed assets, plus a working capital allowance. Net fixed assets are gross assets in service minus accumulated amortization and contributed capital. The table at Exhibit 2 Tab 1 Schedule 2 provides the Rate Base calculations for the periods mentioned above.

Gross Asset – Property, Plant & Equipment and Accumulated Amortization:

The bridge and test year's gross asset balance reflects the capital expenditure programs forecast for both years. These programs are described in detail in the Applicant's written evidence at Exhibit 2, Tab 3, Schedule 1. The justification for capital projects in excess of 1% of the net fixed assets are filed also at Exhibit 2, Tab 3, Schedule 1 followed by a table summarizing the asset additions for each of the years 2006 through 2009, Exhibit 2, Tab 3, Schedule 2 as well as asset disposals, Exhibit 2 Tab 3 Schedule 3.

Capital Budget

The Capital Budget for both the bridge year and test year is included in Exhibit 2, Tab 3, Schedule 1. This provides all the relevant information pertaining to the Capital Program for the Applicant. The review for capital projects in excess of 1% of the net fixed is presented in Exhibit 2, Tab 3, Schedule 1.

Allowance for Working Capital

The calculation of working capital is included in Exhibit 2, Tab 4, Schedule 1.

Rate Base Summary Table

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Bridge Year	2009 Test Year
Net Capital Assets in Service:	-	0	0	0	0
Opening Balance	-	6,990,470	7,086,954	6,961,518	6,802,840
Ending Balance	-	7,086,954	6,961,518	6,802,840	6,898,562
Average Balance	7,096,093	7,038,712	7,024,236	6,882,179	6,850,701
Working Capital Allowance	1,803,062	1,569,072	1,772,537	1,960,263	1,967,423
Total Rate Base	**8,899,155**	**8,607,784**	**8,796,772**	**8,842,442**	**8,818,124**

Expenses for Working Capital	**2006 EDR Approved**	**2006 Actual**	**2007 Actual**	**2008 Bridge Year**	**2009 Test Year**
Eligible Distribution Expenses:					
3500-Distribution Expenses - Operation	175,881	218,322	256,507	284,900	264,900
3550-Distribution Expenses - Maintenance	258,340	247,085	252,713	296,200	292,600
3650-Billing and Collecting	285,425	328,595	314,401	323,100	332,200
3700-Community Relations	21,753	51,191	42,778	56,500	35,600
3800-Administrative and General Expenses	706,526	588,417	636,151	739,200	786,300
3950-Taxes Other Than Income Taxes	30,832	52,866	31,436	33,000	35,000
Total Eligible Distribution Expenses	1,478,756	1,486,476	1,533,986	1,732,900	1,746,600
3350-Power Supply Expenses	10,541,659	8,974,004	10,282,924	11,335,522	11,369,553
Total Expenses for Working Capital	12,020,415	10,460,480	11,816,910	13,068,422	13,116,153
Working Capital factor	15.0%	15.0%	15.0%	15.0%	15.0%
Working Capital Allowance	**1,803,062**	**1,569,072**	**1,772,537**	**1,960,263**	**1,967,423**

Variance Analysis on Rate Base Table

Explanations for variances that exceed the materiality thresholds as prescribed in the Filing Guidelines are set out in the following sections.

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Total Rate Base	$8,899,155	$8,607,784	$8,796,772	$8,842,442	$8,818,124
Threshold of Net fixed assets		$70,961	$70,870	$69,615	$68,028
Variance		($291,371)	$188,988	$45,670	($ 22,113)
Percentage		(3.3%)	2.2%	0.5%	(0.3%)

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Working Capital Allowance	$1,803,062	$1,569,072	$1,772,537	$1,960,263	$1,967,423
Threshold		$19,891	$19,752	$20,453	$24,665
Variance		($233,990)	$203,465	$187,727	$9,365
Percentage		(13.0%)	13.0%	10.6%	0.5%

2006 Actual compared to 2006 Approved

	2006 EDR Approved	**2006 Actual**	**Var $**	**Var %**
Net Capital Assets in Service:				
Opening Balance	7,098,342	6,990,470		
Ending Balance	7,093,843	7,086,954		
Average Balance	7,096,093	7,038,712	(57,381)	(0.8%)
Working Capital Allowance	1,803,062	1,569,072	(233,990)	(13.0%)
Total Rate Base	**8,899,155**	**8,607,784**	**(291,371)**	**(3.3%)**
Expenses for Working Capital				
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	175,881	218,322	42,442	24.1%
3550-Distribution Expenses - Maintenance	258,340	247,085	(11,255)	(4.4%)
3650-Billing and Collecting	285,425	328,595	43,170	15.1%
3700-Community Relations	21,753	51,191	29,438	135.3%
3800-Administrative and General Expenses	706,526	588,417	(118,108)	(16.7%)
3950-Taxes Other Than Income Taxes	30,832	52,866	22,034	71.5%
Total Eligible Distribution Expenses	1,478,756	1,486,476	7,720	0.5%
3350-Power Supply Expenses	10,541,659	8,974,004	(1,567,655)	(14.9%)
Total Expenses for Working Capital	12,020,415	10,460,480	(1,559,935)	(13.0%)
Working Capital factor	15.0%	15.0%	0	0.0%
Working Capital Allowance	**1,803,062**	**1,569,072**	**(233,990)**	**(13.0%)**

The 2006 Actual Rate Base of $8,607,784 is $291,371 or 3.3% lower than the 2006 EDR Approved Rate Base of $8,899,155. The difference can be attributed to two factors: 1) the actual net capital assets in service for 2006 was $57,381 lower than the approved EDR and 2) the actual working capital allowance in 2006 was $233,990 lower than the 2006 EDR approved value.

The Net Capital Assets are affected by:

The Net Capital Assets variance of $57,381 is the difference between the 2006 EDR approved and the 2006 Actual. This variance is a reflection of the total additions for 2005, 2006 and one-half of the additions for 2004. Analysis of the variances related to gross capital assets are shown in Exhibit 2, Tab 2, Schedule 3.

The Working Capital is affected by:

The actual 2006 overall eligible distribution expenses was $7,720 higher than the 2006 EDR approved expenditures.

The Distribution Expenses-Operations showed an increase of $42,442 while the Distribution Expenses-Maintenance showed a decrease of $11,255. The reason for this is because in 2006 the Applicant had to transfer hours spent elsewhere to operations in order to focus on ensuring that all paperwork and engineering drawings were in place to meet the new ESA (Electrical Safety Association) standards and the first audit.

An increase of $43,170 in Billing and Collecting was partly due to an overlap of the ASP billing costs during the switch over period from one to the other. The increase was also the result of looking more closely to the duties being preformed by the office staff and setting out guidelines for where labour dollars were to be charged. In 2006 the Applicant implemented the policy that Administrative and General staff would allocate the portion of their time spent on Billing and Collections and other areas to the proper accounts according to the duties being performed. This results in a truer picture of the cost of Billing and Collecting and Administrative and General Expenses.

An increase of $29,438 occurred in Community Relations because of the Applicant's expenditures related to the third tranche CDM spending.

Also the 2006 Actual Administrative expenses showed a decrease of $118,108 which was partially the result of the Applicant filling a vacancy that occurred when the Financial Administrator left in 2005 and the position was being covered by an outside consultant.

The actual 2006 power supply expenses was $1,567,655 lower than the 2006 EDR approved amount, the difference is due to estimating the cost of power for the 2006 EDR model and the fact that the cost of power is adjusted down each month when the cost of power exceeds the revenues generated for the pass through charges. The variances in the power supply expenses are not within the Applicants influence.

2007 Actual compared to 2006 Actual

	2006 Actual	2007 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	6,990,470	7,086,954	96,484	1.4%
Ending Balance	7,086,954	6,961,518	(125,436)	(1.8%)
Average Balance	7,038,712	7,024,236	(14,476)	(0.2%)
Working Capital Allowance	1,569,072	1,772,537	203,465	13.0%
Total Rate Base	**8,607,784**	**8,796,772**	**188,988**	**2.2%**
Expenses for Working Capital				
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	218,322	256,507	38,185	17.5%
3550-Distribution Expenses - Maintenance	247,085	252,713	5,629	2.3%
3650-Billing and Collecting	328,595	314,401	(14,194)	(4.3%)
3700-Community Relations	51,191	42,778	(8,413)	(16.4%)
3800-Administrative and General Expenses	588,417	636,151	47,733	8.1%
3950-Taxes Other Than Income Taxes	52,866	31,436	(21,430)	(40.5%)
Total Eligible Distribution Expenses	1,486,476	1,533,986	47,510	3.2%
3350-Power Supply Expenses	8,974,004	10,282,924	1,308,920	14.6%
Total Expenses for Working Capital	10,460,480	11,816,910	1,356,430	13.0%
Working Capital factor	15.0%	15.0%	0	0.0%
Working Capital Allowance	1,569,072	1,772,537	203,465	13.0%

The 2007 Actual Rate Base of $8,796,772 is $188,988 or 2.2% higher than the 2006 Actual Rate Base of $8,607,784. The difference can be attributed to two factors: 1) the actual net capital assets in service for 2007 was $14,476 lower than 2006 and 2) the actual working capital allowance in 2007 was $203,465 higher than the 2006 Actual value.

Net Capital Assets are affected by:

The Net Capital Assets in Service opening balance variance of $96,484 represents the total asset additions / disposals for 2006 less accumulated depreciation. In 2006, in addition to the normal capital projects, the Applicant purchased an International Digger Truck which was a replacement vehicle. The net Capital Assets in Service ending balance variance of ($125,436) represents the total assets additions / disposals for 2007 less accumulated depreciation. In 2007 the Applicant sold off surplus vehicles that were fully depreciated and no longer required. Gains on sale of assets are used as revenue offsets.

The Working Capital is affected by:

The actual 2007 overall eligible distribution expenses was $47,510 higher than the 2006 actual expenditures. Within the overall eligible distribution expenses the different components (Distribution Expenses-Operations, Distribution Expenses-Maintenance, Billing and Collecting, Community Relations, Administration and General Expenses and Taxes Other Than Income Taxes) vary by either being higher or lower than the 2006 actual expenditures. Individual component variances that exceed the Board approved thresholds are explained below.

In the Distribution Expenses-Operations the increased cost of $38,185 is primarily due to the reallocation of existing staff labour hours and overheads to assist in the smart meter selection process and provide required upgrades identified as necessary during an analysis of existing meters. The variance is also affected by the shift of more labour and overhead costs to supervision because of the on going increased work load created by the documentation required to meet the ESA new standards.

In the Administrative and General Expenses the increased cost of $47,733 is partially due to taking out Business Credit Risk Insurance to help mitigate the cost to cover write offs due to bankruptcies of commercial accounts in excess of $1,000. This new insurance cost is $13,268 (Account #5635); Injuries & Damages Insurance (Account # 5640) increased by $3,991; Employees Pensions and Benefits (Account #5645) increased by $8,876 due to a large credit in 2006 related to Employee Future Benefits - CICA Section 3461 adjustment; Regulatory Expenses (Account #5655) related to OEB direct costs and ESA fees increased by $2,749; the balance $17,849 is attributed to the increase in labour costs due to overtime incurred during implementation of new standardized billing setups and the upgrade of the billing system to a Windows based system, NorthStar V6.

The decrease in Taxes Other Than Income Taxes of $21,430 in 2007 is due to a correction of $22,000 that was made at the end of 2006 to correct the posting of Ontario Provincial Capital tax as directed by the auditors.

The total Power Supply expense for 2007 is $1,308,920 greater than 2006 because revenues generated in 2007 for the pass through costs were a closer reflection of cost of power supply. However in six months of the year, the cost of power was reduced by $510,113 to bring the total cost into balance with the revenues generated from the sale of power. This is also true in the case of the transmission network charges; where the cost still exceeded revenues by $83,121.

2008 Bridge compared to 2007 Actual

	2007 Actual	2008 Projection	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	7,086,954	6,961,518	(125,436)	(1.8%)
Ending Balance	6,961,518	6,802,840	(158,678)	(2.3%)
Average Balance	7,024,236	6,882,179	(142,057)	(2.0%)
Working Capital Allowance	1,772,537	1,960,263	187,727	10.6%
Total Rate Base	**8,796,772**	**8,842,442**	**45,670**	**0.5%**
Expenses for Working Capital				
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	256,507	284,900	28,393	11.1%
3550-Distribution Expenses - Maintenance	252,713	296,200	43,487	17.2%
3650-Billing and Collecting	314,401	323,100	8,699	2.8%
3700-Community Relations	42,778	56,500	13,722	32.1%
3800-Administrative and General Expenses	636,151	739,200	103,049	16.2%
3950-Taxes Other Than Income Taxes	31,436	33,000	1,564	5.0%
Total Eligible Distribution Expenses	1,533,986	1,732,900	198,914	13.0%
3350-Power Supply Expenses	10,282,924	11,335,522	1,052,598	10.2%
Total Expenses for Working Capital	11,816,910	13,068,422	1,251,511	10.6%
Working Capital factor	15.0%	15.0%	0	0.0%
Working Capital Allowance	**1,772,537**	**1,960,263**	**187,727**	**10.6%**

The 2008 Bridge Actual Rate Base of $8,842,442 is $45,670 or 0.5% higher than the 2007 Actual Rate Base of $8,796,772. The difference can be attributed to two factors: 1) the net capital assets in service for 2008 Bridge year is projected at $142,057 lower than 2007 actual expenditures and 2) the actual working capital allowance in 2008 Bridge year is projected as $187,727 higher than the 2007 actual value.

The Net Capital Assets are affected by:

The net capital assets reduction of $142,057 for the Bridge year is the result of a major piece of transportation equipment being disposed of in 2007 and the associated accumulated depreciation taken off the books in 2007. This resulted in the change in accumulated depreciation in 2007 being at a lower level than normal value which is no longer a factor in 2008. Accumulated Depreciation-2105 in 2007 was ($446,089) and was increased to ($566,760) for the Bridge Year. However, in the first four months of 2008 all general plant assets were reviewed and those no longer in use were written off. For example, obsolete

computers and office equipment in the amount of $75,842, Tools, Shop and Garage Equipment and Power Operated equipment in the value of $28,675.

The Working Capital is affected by:

The 2008 Bridge year working capital exceeds 2007 Actual working capital by $187,727 or 10.6%.

The components of the working capital that exceed the $20,453 threshold are: Distribution Expenses-Operations by $28,393, Distribution Expenses – Maintenance by $43,487; Administrative and General Expenses by $103,049 and Power Supply expenses by $1,052,598.

The major components of the increase in Distribution Expenses-Operations for 2008 relate to the replacement of unsafe meter bases and doing other necessary meter upgrades for $17,000. The other element of the increase involved upgrades to our mapping system at a cost of $13,300.

The major components of the increase in Distribution Expenses-Maintenance for 2008 relate to increases in the time allocated to the cost of maintenance supervision and engineering (Account 5105) of $8,300 to meet the new ESA standards; increase in material and labour allocated to upgrades to maintenance of poles, towers and fixtures (Account 5120) by $22,000 and increase in expenditures to maintenance of overhead conductors and devices (Account 5125) by $23,000. A small portion of the increases in these accounts are offset by a decrease in the other maintenance accounts. The Applicant reviews all maintenance jobs on a case-by-case base and determines which items are priorities and require a needs analysis.

The Administrative and General Expenses for 2008 Bridge year is greater than 2007 actual by $103,049 for the following reasons. The hiring of a contract person to assist in the completion of the rate application and to replace an employee who is going on a leave of absence in order to complete her CGA education between September 2008 and July 2009. The Applicant has also retained a contract employee who was covering a maternity leave to assist in the

implementation of a new financial system which includes an asset management and work orders system in the third phase. The Applicant has also added an additional $10,000 to the budget for the hiring of consultants to address on going new regulatory issues, such as Rate Design, International Financial Reporting Standards (IFRS), etc. that arise in the industry outside of the rate filing process.

The power supply expenses for the 2008 Bridge year is greater than 2007 actual by $1,052,598 because the forecasted cost of power for 2008 is equal to the forecasted sale of electricity. In 2007 the cost of power was reduced by $802,886 to bring the total cost into balance with the revenues generated from the sale of power. The balance of the adjustment is related to the increase volume changes and the price of power. The Applicant has not attempted to forecast the balances in the regulatory variance accounts related to power costs.

2009 Test Year compared to 2008 Bridge

	2008 Projection	2009 Projection	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	6,961,518	6,802,840	(158,678)	(2.3%)
Ending Balance	6,802,840	6,898,562	95,723	1.4%
Average Balance	6,882,179	6,850,701	(31,478)	(0.5%)
Working Capital Allowance	1,960,263	1,967,423	7,160	0.4%
Total Rate Base	**8,842,442**	**8,818,124**	**(24,318)**	**(0.3%)**
Expenses for Working Capital				
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	284,900	264,900	(20,000)	(7.0%)
3550-Distribution Expenses - Maintenance	296,200	292,600	(3,600)	(1.2%)
3650-Billing and Collecting	323,100	332,200	9,100	2.8%
3700-Community Relations	56,500	35,600	(20,900)	(37.0%)
3800-Administrative and General Expenses	739,200	786,300	47,100	6.4%
3950-Taxes Other Than Income Taxes	33,000	35,000	2,000	6.1%
Total Eligible Distribution Expenses	1,732,900	1,746,600	13,700	0.8%
3350-Power Supply Expenses	11,335,522	11,369,553	34,032	0.3%
Total Expenses for Working Capital	13,068,422	13,116,153	47,732	0.4%
Working Capital factor	15.0%	15.0%	0	0.0%
Working Capital Allowance	**1,960,263**	**1,967,423**	**7,160**	**0.4%**

The 2009 Test Year Rate Base of $8,818,124 is $24,318 or (0.3%) lower than the 2008 Bridge Year Rate Base of $8,842,442. The difference can be attributed to two factors: 1) the net capital assets in service for 2009 Test Year are projected to be $31,478 lower than the 2008 Bridge Year expenditures and 2) the working capital allowance in 2009 Test Year is projected as $7,160 higher than the 2008 Bridge year value.

The Net Capital Assets are affected by:

The opening balance of the net capital assets shows a reduction of $158,678 for the 2008 Bridge year. This is the result of the Applicant disposing of the major piece of equipment in 2007 which was replaced in 2006. The write off of the equipment resulted in the net accumulated depreciation in 2007 being lower than normal. In 2008 the change in accumulated amortization was no longer affected by the write off of that piece of equipment.

The closing balance of net capital assets for the 2009 Test Year shows an increase in capital expenditure of $95,723. However, the Applicant would like to point out that these forecast expenditures do not include any incremental capital or maintenance costs related to the purchase or on going cost of smart meters. The Applicant understands that the corresponding Smart Meter costs are to be allocated to Account 1555-Smart Meter Capital Recovery Offset Variance and to Account 1556-Smart meter OM&A Variance Account and will be recovered through a rate rider approved by the Board in a separate application.

The Working Capital is affected by:

The 2009 Test Year working capital is higher than the 2008 Bridge year working capital by $7,160 or (0.4%).

The components of the working capital that exceed the $23,652 threshold are: Administrative and General Expenses by $47,100 and an increase in Power Supply expenses by $34,032.

The increase of $47,100 in Administrative and General Expenses is due to increased travel expenditures of $6,000; increase in general administration expenses of $18,900 related to the overlapping of staff due to the return of a staff member that took a leave of absence in 2008 and the need for increased staffing while the Applicant completes the second phase of the Financial System upgrade related to conversion of the financial software related to the general ledger, accounts payable, misc receivables, payable and inventory in 2009 and the planning of implementation of operations and asset management to take place in 2010 and the migration to the new International Financial Reporting Standards (IFRS's). The increase of $6,500 in Office Supplies and Expenses which includes bank charges, subscriptions, books, bulletins, small office equipment, stationery, printing, computer expenses, courier, delivery charges and miscellaneous general administration expenses.

The Applicant is also looking at increases in property insurance and business credit risk insurance of $1,200 and an increase of $4,000 in premiums for Injuries and Damage Insurance. The Applicant has forecasted an increase in Regulatory expenses of $39,400. This increase is broken down into two parts. The first part is an increase of $5,400 to cover additional OEB cost awards and fees and ESA fees. The second part of this cost is $34,000 which is one-third of the forecasted cost related to the preparation and presentation of the 2009 Cost of Service Rate Application.

The power supply expenses for the 2009 Test Year are higher than 2008 Bridge year by $34,032 because the Applicant has forecasted an increase in the cost of power for 2009. This amount is a blend of an increase in the total kWh consumed due to growth and a reduction in the rates charged to the customers for Transmission Network and Connection charges to better reflect the true cost and revenues for these two charges. The Applicant is hoping that by adjusting the Transmission Network and Connection charges to the customers effective May 1, 2009, the approved pass-through costs will not create the same size variances that have occurred in the past couple of years.

Fixed Assets

Fixed Asset Continuity Statements

		2006 EDR	Variance to 2006 Actual			2006	2007 Changes			2007
		Approved	Additions	Ret./Other *	Amortization	Balance	Additions	Ret./Other *	Amortization	Balance
1805-Land										
	Gross Assets	$ 46,065.54	$ -	$ -	$ -	$ 46,065.54	$ -	$ -	$ -	$ 46,065.54
	Accumulated Amortization	$ -	$ -	$ 0.46	$ (0.46)	$ -	$ -	$ -	$ -	$ -
	Net Book Value	$ 46,065.54	$ -	$ 0.46	$ (0.46)	$ 46,065.54	$ -	$ -	$ -	$ 46,065.54
1806-Land Rights										
	Gross Assets	$ 24,407.63	$ 2,901.00	$ -	$ -	$ 27,308.63	$ 3,381.19	$ -	$ -	$ 30,689.82
	Accumulated Amortization	$ (1,712.23)	$ -	$ (747.10)	$ (531.40)	$ (2,990.73)	$ -	$ -	$ (571.00)	$ (3,561.73)
	Net Book Value	$ 22,695.40	$ 2,901.00	$ (747.10)	$ (531.40)	$ 24,317.90	$ 3,381.19	$ -	$ (571.00)	$ 27,128.09
1808-Buildings and Fixtures										
	Gross Assets	$ 2,307.56	$ -	$ -	$ -	$ 2,307.56	$ -	$ -	$ -	$ 2,307.56
	Accumulated Amortization	$ (1,806.06)	$ -	$ (88.50)	$ (59.00)	$ (1,953.56)	$ -	$ -	$ (59.00)	$ (2,012.56)
	Net Book Value	$ 501.50	$ -	$ (88.50)	$ (59.00)	$ 354.00	$ -	$ -	$ (59.00)	$ 295.00
1820-Distribution Station Equipment - Normally Primary below 50 kV										
	Gross Assets	$ 1,213,442.99	$ 51,741.02	$ -	$ -	$ 1,270,184.01	$ -	$ -	$ -	$ 1,270,184.01
	Accumulated Amortization	$ (588,572.27)	$ -	$ (54,009.73)	$ (35,077.00)	$ (677,659.00)	$ -	$ -	$ (35,077.00)	$ (712,736.00)
	Net Book Value	$ 629,870.72	$ 51,741.02	$ (54,009.73)	$ (35,077.00)	$ 592,525.01	$ -	$ -	$ (35,077.00)	$ 557,448.01
1825-Storage Battery Equipment										
	Gross Assets	0.00	$ 2,154.99	$ -	$ -	$ 2,154.99	$ -	$ -	$ -	$ 2,154.99
	Accumulated Amortization	$ -	$ -	$ (215.50)	$ (431.00)	$ (646.50)	$ -	$ -	$ (431.00)	$ (1,077.50)
	Net Book Value	$ -	$ 2,154.99	$ (215.50)	$ (431.00)	$ 1,508.49	$ -	$ -	$ (431.00)	$ 1,077.49
1830-Poles, Towers and Fixtures										
	Gross Assets	$ 1,134,967.52	$ 84,239.47	$ 33,744.85	$ -	$ 1,252,951.84	$ 84,927.19	$ -	$ -	$ 1,337,879.03
	Accumulated Amortization	$ (502,126.59)	$ -	$ (69,048.09)	$ (47,343.76)	$ (618,518.44)	$ -	$ -	$ (49,286.45)	$ (667,804.89)
	Net Book Value	$ 632,840.93	$ 84,239.47	$ (35,303.24)	$ (47,343.76)	$ 634,433.40	$ 84,927.19	$ -	$ (49,286.45)	$ 670,074.14
1835-Overhead Conductors and Devices										
	Gross Assets	$ 824,452.69	$ 124,301.49	$ 36,084.96	$ -	$ 984,839.14	$ 64,645.07	$ -	$ -	$ 1,049,484.21
	Accumulated Amortization	$ (325,827.36)	$ -	$ (51,935.24)	$ (37,622.22)	$ (415,384.82)	$ -	$ -	$ (39,094.79)	$ (454,479.61)
	Net Book Value	$ 498,625.33	$ 124,301.49	$ (15,850.28)	$ (37,622.22)	$ 569,454.32	$ 64,645.07	$ -	$ (39,094.79)	$ 595,004.60
1840-Underground Conduit										
	Gross Assets	$ 943,703.35	$ 196,216.64	$ 28,232.81	$ -	$ 1,168,152.79	$ 18,754.75	$ -	$ -	$ 1,186,907.54
	Accumulated Amortization	$ (316,638.96)	$ -	$ (56,152.99)	$ (44,722.90)	$ (417,514.85)	$ -	$ -	$ (46,685.79)	$ (464,200.64)
	Net Book Value	$ 627,064.39	$ 196,216.64	$ (27,920.18)	$ (44,722.90)	$ 750,637.94	$ 18,754.75	$ -	$ (46,685.79)	$ 722,706.90
1845-Underground Conductors and Devices										
	Gross Assets	$ 1,362,702.12	$ 187,896.50	$ 14,908.18	$ -	$ 1,565,506.80	$ 9,758.99	$ -	$ -	$ 1,575,265.79
	Accumulated Amortization	$ (522,808.86)	$ -	$ (79,246.10)	$ (59,579.71)	$ (661,634.67)	$ -	$ -	$ (62,088.45)	$ (723,723.12)
	Net Book Value	$ 839,893.26	$ 187,896.50	$ (64,337.92)	$ (59,579.71)	$ 903,872.13	$ 9,758.99	$ -	$ (62,088.45)	$ 851,542.67
1850-Line Transformers										
	Gross Assets	$ 2,251,163.52	$ 178,673.38	$ 10,557.77	$ -	$ 2,440,394.67	$ 87,367.46	$ -	$ -	$ 2,527,762.13
	Accumulated Amortization	$ (1,022,085.84)	$ -	$ (116,922.52)	$ (84,367.75)	$ (1,223,376.11)	$ -	$ -	$ (88,706.59)	$ (1,312,082.70)
	Net Book Value	$ 1,229,077.68	$ 178,673.38	$ (106,364.75)	$ (84,367.75)	$ 1,217,018.56	$ 87,367.46	$ -	$ (88,706.59)	$ 1,215,679.43
1855-Services										
	Gross Assets	$ 2,753,397.26	$ 178,669.49	$ 26,153.59	$ -	$ 2,958,220.34	$ 27,156.70	$ 0.00	$ -	$ 2,985,377.04
	Accumulated Amortization	$ (1,176,782.18)	$ -	$ (162,038.16)	$ (114,951.34)	$ (1,453,771.68)	$ -	$ -	$ (116,583.61)	$ (1,570,355.29)
	Net Book Value	$ 1,576,615.08	$ 178,669.49	$ (135,884.57)	$ (114,951.34)	$ 1,504,448.66	$ 27,156.70	$ 0.00	$ (116,583.61)	$ 1,415,021.75
1860-Meters										
	Gross Assets	$ 775,201.76	$ 25,101.68	$ (9,392.12)	$ -	$ 790,911.32	$ 6,669.71	$ 0.00	$ -	$ 797,581.03
	Accumulated Amortization	$ (371,795.72)	$ -	$ (37,402.17)	$ (26,002.63)	$ (435,200.52)	$ -	$ -	$ (26,403.26)	$ (461,603.78)
	Net Book Value	$ 403,406.04	$ 25,101.68	$ (46,794.29)	$ (26,002.63)	$ 355,710.80	$ 6,669.71	$ 0.00	$ (26,403.26)	$ 335,977.25

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	2008 Changes			2008	2009 Changes			2009
	Additions	Ret./Other *	Amortization	Balance	Additions	Ret./Other *	Amortization	Balance
1805-Land								
Gross Assets	$ -	$ -	$ -	$ 46,065.54	$ -	$ -	$ -	$ 46,065.54
Accumulated Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value	$ -	$ -	$ -	$ 46,065.54	$ -	$ -	$ -	$ 46,065.54
1806-Land Rights								
Gross Assets	$ 4,000.00	$ -	$ -	$ 34,689.82	$ 4,000.00	$ -	$ -	$ 38,689.82
Accumulated Amortization	$ -	$ -	$ (654.00)	$ (4,215.73)	$ -	$ -	$ (734.00)	$ (4,949.73)
Net Book Value	$ 4,000.00	$ -	$ (654.00)	$ 30,474.09	$ 4,000.00	$ -	$ (734.00)	$ 33,740.09
1808-Buildings and Fixtures								
Gross Assets	$ -	$ -	$ -	$ 2,307.56	$ -	$ -	$ -	$ 2,307.56
Accumulated Amortization	$ -	$ -	$ (59.00)	$ (2,071.56)	$ -	$ -	$ (59.00)	$ (2,130.56)
Net Book Value	$ -	$ -	$ (59.00)	$ 236.00	$ -	$ -	$ (59.00)	$ 177.00
1820-Distribution Station Equipment - Normally Primary below 50 kV								
Gross Assets	$ -	$ -	$ -	$ 1,270,184.01	$ -	$ -	$ -	$ 1270,184.01
Accumulated Amortization	$ -	$ -	$ (35,077.00)	$ (747,813.00)	$ -	$ -	$ (35,077.00)	$ (782,890.00)
Net Book Value	$ -	$ -	$ (35,077.00)	$ 522,371.01	$ -	$ -	$ (35,077.00)	$ 487,294.01
1825-Storage Battery Equipment								
Gross Assets	$ -	$ -	$ -	$ 2,154.99	$ -	$ -	$ -	$ 2,154.99
Accumulated Amortization	$ -	$ -	$ (431.00)	$ (1,508.50)	$ -	$ -	$ (431.00)	$ (1,939.50)
Net Book Value	$ -	$ -	$ (431.00)	$ 646.49	$ -	$ -	$ (431.00)	$ 215.49
1830-Poles, Towers and Fixtures								
Gross Assets	$ 70,700.00	$ -	$ -	$ 1,408,579.03	$ 110,500.00	$ -	$ -	$ 1519,079.03
Accumulated Amortization	$ -	$ -	$ (50,690.24)	$ (718,495.13)	$ -	$ -	$ (53,768.11)	$ (772,263.24)
Net Book Value	$ 70,700.00	$ -	$ (50,690.24)	$ 690,083.90	$ 110,500.00	$ -	$ (53,768.11)	$ 746,815.79
1835-Overhead Conductors and Devices								
Gross Assets	$ 82,300.00	$ -	$ -	$ 1,131784.21	$ 136,300.00	$ -	$ -	$ 1268,084.21
Accumulated Amortization	$ -	$ -	$ (40,963.99)	$ (495,443.60)	$ -	$ -	$ (44,993.06)	$ (540,436.66)
Net Book Value	$ 82,300.00	$ -	$ (40,963.99)	$ 636,340.61	$ 136,300.00	$ -	$ (44,993.06)	$ 727,647.55
1840-Underground Conduit								
Gross Assets	$ 6,700.00	$ -	$ -	$ 1193,607.54	$ 5,000.00	$ -	$ -	$ 1198,607.54
Accumulated Amortization	$ -	$ -	$ (47,192.42)	$ (511393.06)	$ -	$ -	$ (47,324.82)	$ (558,717.88)
Net Book Value	$ 6,700.00	$ -	$ (47,192.42)	$ 682,214.48	$ 5,000.00	$ -	$ (47,324.82)	$ 639,889.66
1845-Underground Conductors and Devices								
Gross Assets	$ 16,500.00	$ -	$ -	$ 1591765.79	$ 19,200.00	$ -	$ -	$ 1610,965.79
Accumulated Amortization	$ -	$ -	$ (62,608.95)	$ (786,332.07)	$ -	$ -	$ (63,145.15)	$ (849,477.22)
Net Book Value	$ 16,500.00	$ -	$ (62,608.95)	$ 805,433.72	$ 19,200.00	$ -	$ (63,145.15)	$ 761488.57
1850-Line Transformers								
Gross Assets	$ 147,000.00	$ -	$ -	$ 2,674,762.13	$ 266,000.00	$ -	$ -	$ 2,940,762.13
Accumulated Amortization	$ -	$ -	$ (93,384.86)	$ (1405,467.56)	$ -	$ -	$ (101,630.95)	$ (1507,098.51)
Net Book Value	$ 147,000.00	$ -	$ (93,384.86)	$ 1269,294.57	$ 266,000.00	$ -	$ (101,630.95)	$ 1433,663.62
1855-Services								
Gross Assets	$ 22,900.00	$ -	$ -	$ 3,008,277.04	$ 59,600.00	$ -	$ -	$ 3,067,877.04
Accumulated Amortization	$ -	$ -	$ (117,044.14)	$ (1687,399.43)	$ -	$ -	$ (118,162.60)	$ (1805,562.03)
Net Book Value	$ 22,900.00	$ -	$ (117,044.14)	$ 1320,877.61	$ 59,600.00	$ -	$ (118,162.60)	$ 1262,315.01
1860-Meters								
Gross Assets	$ 15,000.00	$ -	$ -	$ 812,581.03	$ 15,000.00	$ -	$ -	$ 827,581.03
Accumulated Amortization	$ -	$ -	$ (26,839.40)	$ (488,443.18)	$ -	$ -	$ (27,439.40)	$ (515,882.58)
Net Book Value	$ 15,000.00	$ -	$ (26,839.40)	$ 324,137.85	$ 15,000.00	$ -	$ (27,439.40)	$ 311,698.45

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		2006 EDR	Variance to 2006 Actual			2006	2007 Changes			2007
		Approved	Additions	Ret./Other *	Amortization	Balance	Additions	Ret./Other *	Amortization	Balance
1905-Land										
	Gross Assets	$ 8,639.65	$ -	$ -	$ -	$ 8,639.65	$ -	$ -	$ -	$ 8,639.65
	Accumulated Amortization	$ -	$ -	$ 0.35	$ (0.35)	$ -	$ -	$ -	$ -	$ -
	Net Book Value	$ 8,639.65	$ -	$ 0.35	$ (0.35)	$ 8,639.65	$ -	$ -	$ -	$ 8,639.65
1908-Buildings and Fixtures										
	Gross Assets	$ 1,020,233.90	$ -	$ -	$ -	$ 1,020,233.90	$ -	$ -	$ -	$ 1,020,233.90
	Accumulated Amortization	$ (135,885.88)	$ -	$ (32,728.71)	$ (21,819.14)	$ (190,433.73)	$ -	$ -	$ (21,819.14)	$ (212,252.87)
	Net Book Value	$ 884,348.02	$ -	$ (32,728.71)	$ (21,819.14)	$ 829,800.17	$ -	$ -	$ (21,819.14)	$ 807,981.03
1915-Office Furniture and Equipment										
	Gross Assets	$ 71,974.33	$ 7,941.87	$ 429.02	$ -	$ 80,345.21	$ 18,265.95	$ -	$ -	$ 98,611.16
	Accumulated Amortization	$ (40,060.13)	$ -	$ (9,716.83)	$ (6,341.79)	$ (56,118.75)	$ -	$ -	$ (6,912.93)	$ (63,031.68)
	Net Book Value	$ 31,914.20	$ 7,941.87	$ (9,287.81)	$ (6,341.79)	$ 24,226.46	$ 18,265.95	$ -	$ (6,912.93)	$ 35,579.48
1920-Computer Equipment - Hardware										
	Gross Assets	$ 177,898.27	$ 25,446.21	$ (434.99.55)	$ -	$ 159,844.93	$ 25,739.58	$ -	$ -	$ 185,584.51
	Accumulated Amortization	$ (150,928.06)	$ -	$ 228.63.82	$ (10,693.80)	$ (138,758.04)	$ -	$ -	$ (14,316.59)	$ (153,074.63)
	Net Book Value	$ 26,970.21	$ 25,446.21	$ (206.35.73)	$ (10,693.80)	$ 21,086.89	$ 25,739.58	$ -	$ (14,316.59)	$ 32,509.88
1925-Computer Software										
	Gross Assets	$ 67,859.73	$ 6,201.65	$ 1,750.00	$ -	$ 75,811.38	$ 52,270.32	$ -	$ -	$ 128,081.70
	Accumulated Amortization	$ (61,379.93)	$ -	$ (6,479.81)	$ (4,267.82)	$ (72,127.56)	$ -	$ -	$ (11,361.16)	$ (83,488.72)
	Net Book Value	$ 6,479.80	$ 6,201.65	$ (4,729.81)	$ (4,267.82)	$ 3,683.82	$ 52,270.32	$ -	$ (11,361.16)	$ 44,592.98
1930-Transportation Equipment										
	Gross Assets	$ 639,077.83	$ 214,540.74	$ 116,361.75	$ -	$ 969,980.32	$ 60,580.00	$ (190,289.22)	$ -	$ 840,271.10
	Accumulated Amortization	$ (487,252.21)	$ -	$ 128.56.95	$ (59,503.57)	$ (533,898.83)	$ -	$ 190,288.77	$ (77,233.10)	$ (420,843.16)
	Net Book Value	$ 151,825.62	$ 214,540.74	$ 129,218.70	$ (59,503.57)	$ 436,081.49	$ 60,580.00	$ (0.45)	$ (77,233.10)	$ 419,427.94
1935-Stores Equipment										
	Gross Assets	$ 19,723.64	$ -	$ 210.60	$ -	$ 19,934.24	$ -	$ -	$ -	$ 19,934.24
	Accumulated Amortization	$ (13,430.86)	$ -	$ (2,976.01)	$ (1,390.81)	$ (17,797.68)	$ -	$ -	$ (855.81)	$ (18,653.49)
	Net Book Value	$ 6,292.78	$ -	$ (2,765.41)	$ (1,390.81)	$ 2,136.56	$ -	$ -	$ (855.81)	$ 1,280.75
1940-Tools, Shop and Garage Equipment										
	Gross Assets	$ 41,903.65	$ 26,500.01	$ 1,139.63	$ -	$ 69,543.29	$ 3,952.30	$ -	$ -	$ 73,495.59
	Accumulated Amortization	$ (28,181.55)	$ -	$ (4,984.76)	$ (4,782.43)	$ (37,948.74)	$ -	$ -	$ (4,619.00)	$ (42,567.74)
	Net Book Value	$ 13,722.10	$ 26,500.01	$ (3,845.13)	$ (4,782.43)	$ 31,594.55	$ 3,952.30	$ -	$ (4,619.00)	$ 30,927.85
1945-Measurement and Testing Equipment										
	Gross Assets	$ 41,282.48	$ 862.92	$ (0.00)	$ -	$ 42,145.40	$ -	$ -	$ -	$ 42,145.40
	Accumulated Amortization	$ (20,380.71)	$ -	$ (457.43.7)	$ (3,094.04)	$ (28,049.12)	$ -	$ -	$ (3,135.58)	$ (31,184.70)
	Net Book Value	$ 20,901.77	$ 862.92	$ (457.43.7)	$ (3,094.04)	$ 14,096.28	$ -	$ -	$ (3,135.58)	$ 10,960.70
1950-Power Operated Equipment										
	Gross Assets	$ 84,511.13	$ 14,483.92	$ -	$ -	$ 98,995.05	$ -	$ -	$ -	$ 98,995.05
	Accumulated Amortization	$ (58,832.59)	$ -	$ (10,536.96)	$ (8,230.00)	$ (77,599.55)	$ -	$ -	$ (8,230.00)	$ (85,829.55)
	Net Book Value	$ 25,678.54	$ 14,483.92	$ (10,536.96)	$ (8,230.00)	$ 21,395.50	$ -	$ -	$ (8,230.00)	$ 13,165.50
1955-Communication Equipment										
	Gross Assets	$ 23,853.66	$ 6,480.32	$ 473.85	$ -	$ 30,807.82	$ 496.78	$ (0.00)	$ -	$ 31,304.60
	Accumulated Amortization	$ (10,092.04)	$ -	$ (3,810.21)	$ (2,986.42)	$ (16,888.67)	$ -	$ -	$ (3,011.25)	$ (19,899.92)
	Net Book Value	$ 13,761.62	$ 6,480.32	$ (3,336.37)	$ (2,986.42)	$ 13,919.15	$ 496.78	$ (0.00)	$ (3,011.25)	$ 11,404.68
1960-Miscellaneous Equipment										
	Gross Assets	$ 1,709.10	$ 7,753.18	$ -	$ -	$ 9,462.28	$ -	$ -	$ -	$ 9,462.28
	Accumulated Amortization	$ (685.46)	$ -	$ (657.47)	$ (1078.76)	$ (2,421.69)	$ -	$ -	$ (1771.00)	$ (4,192.69)
	Net Book Value	$ 1,023.64	$ 7,753.18	$ (657.47)	$ (1078.76)	$ 7,040.59	$ -	$ -	$ (1771.00)	$ 5,269.59
1980-System Supervisory Equipment										
	Gross Assets	$ 169,148.70	$ -	$ 1,721.05	$ -	$ 170,869.75	$ -	$ -	$ -	$ 170,869.75
	Accumulated Amortization	$ (45,302.61)	$ -	$ (27,070.36)	$ (18,124.78)	$ (90,497.75)	$ -	$ -	$ (18,124.78)	$ (108,622.53)
	Net Book Value	$ 123,846.09	$ -	$ (25,349.31)	$ (18,124.78)	$ 80,372.00	$ -	$ -	$ (18,124.78)	$ 62,247.22
1985-Sentinel Lighting Rental Units										
	Gross Assets	$ 2,516.21	$ -	$ -	$ -	$ 2,516.21	$ -	$ -	$ -	$ 2,516.21
	Accumulated Amortization	$ (2,516.21)	$ -	$ -	$ -	$ (2,516.21)	$ -	$ -	$ -	$ (2,516.21)
	Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1995-Contributions and Grants - Credit										
	Gross Assets	$ (728,216.53)	$ (138,546.27)	$ (140,703.16)	$ -	$ (1,007,465.95)	$ 46,975.44	$ (0.00)	$ -	$ (960,490.51)
	Accumulated Amortization	$ -	$ -	$ 140,702.68	$ (140,702.68)	$ -	$ -	$ (46,975.44)	$ 46,975.44	$ 0.00
	Net Book Value	$ (728,216.53)	$ (138,546.27)	$ (0.47)	$ (140,702.68)	$ (1,007,465.95)	$ 46,975.44	$ (46,975.44)	$ 46,975.44	$ (960,490.51)
TOTAL										
	Gross Assets	$ 12,978,927.66	$ 1,203,560.21	$ 78,173.24	$ -	$ 14,260,661.11	$ 510,941.43	$ (190,289.22)	$ -	$ 14,581,313.32
	Accumulated Amortization	$ (5,885,084.31)	$ -	$ (554,917.33)	$ (733,705.56)	$ (7,173,707.20)	$ -	$ 143,313.33	$ (589,401.84)	$ (7,619,795.71)
	Net Book Value	$ 7,093,843.35	$ 1,203,560.21	$ (476,744.09)	$ (733,705.56)	$ 7,086,953.91	$ 510,941.43	$ (46,975.89)	$ (589,401.84)	$ 6,961,517.61

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		2008 Changes			2008	2009 Changes			2009
		Additions	Ret./Other *	Amortization	Balance	Additions	Ret./Other *	Amortization	Balance
1905-Land									
	Gross Assets	$ -	$ -	$ -	$ 8,639.65	$ -	$ -	$ -	$ 8,639.65
	Accumulated Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Net Book Value	$ -	$ -	$ -	$ 8,639.65	$ -	$ -	$ -	$ 8,639.65
1908-Buildings and Fixtures									
	Gross Assets	$ -	$ -	$ -	$ 1,020,233.90	$ -	$ -	$ -	$ 1,020,233.90
	Accumulated Amortization	$ -	$ -	$ (21,819.14)	$ (234,072.01)	$ -	$ -	$ (21,819.14)	$ (255,891.15)
	Net Book Value	$ -	$ -	$ (21,819.14)	$ 786,161.89	$ -	$ -	$ (21,819.14)	$ 764,342.75
1915-Office Furniture and Equipment									
	Gross Assets	$ 20,000.00	$ (20,559.06)	$ -	$ 98,052.10	$ -	$ -	$ -	$ 98,052.10
	Accumulated Amortization	$ -	$ 20,559.06	$ (8,263.95)	$ (50,736.57)	$ -	$ -	$ (6,537.95)	$ (57,274.52)
	Net Book Value	$ 20,000.00	$ -	$ (8,263.95)	$ 47,315.53	$ -	$ -	$ (6,537.95)	$ 40,777.58
1920-Computer Equipment - Hardware									
	Gross Assets	$ 13,000.00	$ (55,283.89)	$ -	$ 143,300.62	$ 29,000.00	$ -	$ -	$ 172,300.62
	Accumulated Amortization	$ -	$ 55,283.89	$ (18,399.00)	$ (116,139.74)	$ -	$ -	$ (21,154.05)	$ (137,343.79)
	Net Book Value	$ 13,000.00	$ -	$ (18,399.00)	$ 27,110.88	$ 29,000.00	$ -	$ (21,154.05)	$ 34,956.83
1925-Computer Software									
	Gross Assets	$ 96,000.00	$ -	$ -	$ 224,081.70	$ 82,000.00	$ -	$ -	$ 306,081.70
	Accumulated Amortization	$ -	$ -	$ (34,457.83)	$ (117,946.55)	$ -	$ -	$ (63,090.67)	$ (181,037.22)
	Net Book Value	$ 96,000.00	$ -	$ (34,457.83)	$ 106,135.15	$ 82,000.00	$ -	$ (63,090.67)	$ 125,044.48
1930-Transportation Equipment									
	Gross Assets	$ -	$ -	$ -	$ 840,271.10	$ 45,000.00	$ -	$ -	$ 885,271.10
	Accumulated Amortization	$ -	$ -	$ (76,748.04)	$ (497,591.20)	$ -	$ -	$ (81,248.00)	$ (578,839.20)
	Net Book Value	$ -	$ -	$ (76,748.04)	$ 342,679.90	$ 45,000.00	$ -	$ (81,248.00)	$ 306,431.90
1935-Stores Equipment									
	Gross Assets	$ 1,000.00	$ -	$ -	$ 20,934.24	$ 1,000.00	$ -	$ -	$ 21,934.24
	Accumulated Amortization	$ -	$ -	$ (344.81)	$ (18,998.30)	$ -	$ -	$ (444.81)	$ (19,443.11)
	Net Book Value	$ 1,000.00	$ -	$ (344.81)	$ 1,935.94	$ 1,000.00	$ -	$ (444.81)	$ 2,491.13
1940-Tools, Shop and Garage Equipment									
	Gross Assets	$ 14,000.00	$ (17,954.58)	$ -	$ 69,541.01	$ 2,000.00	$ -	$ -	$ 71,541.01
	Accumulated Amortization	$ -	$ 17,954.58	$ (5,185.65)	$ (29,798.81)	$ -	$ -	$ (5,985.65)	$ (35,784.46)
	Net Book Value	$ 14,000.00	$ -	$ (5,185.65)	$ 39,742.20	$ 2,000.00	$ -	$ (5,985.65)	$ 35,756.55
1945-Measurement and Testing Equipment									
	Gross Assets	$ 1,000.00	$ -	$ -	$ 43,145.40	$ 1,000.00	$ -	$ -	$ 44,145.40
	Accumulated Amortization	$ -	$ -	$ (2,999.28)	$ (34,183.98)	$ -	$ -	$ (2,798.28)	$ (36,982.26)
	Net Book Value	$ 1,000.00	$ -	$ (2,999.28)	$ 8,961.42	$ 1,000.00	$ -	$ (2,798.28)	$ 7,163.14
1950-Power Operated Equipment									
	Gross Assets	$ -	$ (10,720.00)	$ -	$ 88,275.05	$ -	$ -	$ -	$ 88,275.05
	Accumulated Amortization	$ -	$ 10,720.00	$ (5,018.54)	$ (80,128.09)	$ -	$ -	$ (1,810.00)	$ (81,938.09)
	Net Book Value	$ -	$ -	$ (5,018.54)	$ 8,146.96	$ -	$ -	$ (1,810.00)	$ 6,336.96
1955-Communication Equipment									
	Gross Assets	$ -	$ -	$ -	$ 31,304.60	$ -	$ -	$ -	$ 31,304.60
	Accumulated Amortization	$ -	$ -	$ (3,036.09)	$ (22,936.01)	$ -	$ -	$ (2,151.09)	$ (25,087.10)
	Net Book Value	$ -	$ -	$ (3,036.09)	$ 8,368.59	$ -	$ -	$ (2,151.09)	$ 6,217.50
1960-Miscellaneous Equipment									
	Gross Assets	$ 2,500.00	$ -	$ -	$ 11,962.28	$ -	$ -	$ -	$ 11,962.28
	Accumulated Amortization	$ -	$ -	$ (1,936.00)	$ (6,128.69)	$ -	$ -	$ (1,601.00)	$ (7,729.69)
	Net Book Value	$ 2,500.00	$ -	$ (1,936.00)	$ 5,833.59	$ -	$ -	$ (1,601.00)	$ 4,232.59
1980-System Supervisory Equipment									
	Gross Assets	$ -	$ -	$ -	$ 170,869.75	$ -	$ -	$ -	$ 170,869.75
	Accumulated Amortization	$ -	$ -	$ (18,124.78)	$ (126,747.31)	$ -	$ -	$ (17,671.71)	$ (144,419.02)
	Net Book Value	$ -	$ -	$ (18,124.78)	$ 44,122.44	$ -	$ -	$ (17,671.71)	$ 26,450.73
1985-Sentinel Lighting Rental Units									
	Gross Assets	$ -	$ -	$ -	$ 2,516.21	$ -	$ -	$ -	$ 2,516.21
	Accumulated Amortization	$ -	$ -	$ -	$ (2,516.21)	$ -	$ -	$ -	$ (2,516.21)
	Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1995-Contributions and Grants - Credit									
	Gross Assets	$ -	$ -	$ -	$ (960,490.51)	$ -	$ -	$ -	$ (960,490.51)
	Accumulated Amortization	$ -	$ -	$ -	$ 0.00	$ -	$ -	$ -	$ 0.00
	Net Book Value	$ -	$ -	$ -	$ (960,490.51)	$ -	$ -	$ -	$ (960,490.51)
TOTAL									
	Gross Assets	$ 512,600.00	$ (104,517.53)	$ -	$ 14,989,395.79	$ 775,600.00	$ -	$ -	$ 15,764,995.79
	Accumulated Amortization	$ -	$ 104,517.53	$ (671,278.11)	$ (8,186,556.29)	$ -	$ -	$ (719,077.44)	$ (8,905,633.73)
	Net Book Value	$ 512,600.00	$ -	$ (671,278.11)	$ 6,802,839.50	$ 775,600.00	$ -	$ (719,077.44)	$ 6,859,362.06

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Gross Assets Table

Account Description	2009 Projection	2008 Projection	Var $ 2008 to 2009	2007 Actual	Var $ 2007 to 2008	2006 Actual	Var $ 2006 vs 2007	2006 EDR Approved	Var $ 2006 Actual to 2006 EDR
1805-Land	$ 46,066	$ 46,066	$ -	$ 46,066	$ -	$ 46,066	$ -	$ 46,066	$ -
1806-Land Rights	$ 38,690	$ 34,690	$ 4,000	$ 30,690	$ 4,000	$ 27,309	$ 3,381	$ 24,408	$ 2,901
1808-Buildings and Fixtures	$ 2,308	$ 2,308	$ -	$ 2,308	$ -	$ 2,308	$ -	$ 2,308	$ -
1820-Distribution Station Equipment - Normally Primary below 50 kV	$ 1,270,184	$ 1,270,184	$ -	$ 1,270,184	$ -	$ 1,270,184	$ -	$ 1,218,443	$ 51,741
1825-Storage Battery Equipment	$ 2,155	$ 2,155	$ -	$ 2,155	$ -	$ 2,155	$ -	$ -	$ 2,155
1830-Poles, Towers and Fixtures	$ 1,519,079	$ 1,408,579	$ 110,500	$ 1,337,879	$ 70,700	$ 1,252,952	$ 84,927	$ 1,134,968	$ 117,984
1835-Overhead Conductors and Devices	$ 1,268,084	$ 1,131,784	$ 136,300	$ 1,049,484	$ 82,300	$ 984,839	$ 64,645	$ 824,453	$ 160,386
1840-Underground Conduit	$ 1,198,608	$ 1,193,608	$ 5,000	$ 1,186,908	$ 6,700	$ 1,168,153	$ 18,755	$ 943,703	$ 224,449
1845-Underground Conductors and Devices	$ 1,610,966	$ 1,591,766	$ 19,200	$ 1,575,266	$ 16,500	$ 1,565,507	$ 9,759	$ 1,362,702	$ 202,805
1850-Line Transformers	$ 2,980,762	$ 2,674,762	$ 306,000	$ 2,527,762	$ 147,000	$ 2,440,395	$ 87,367	$ 2,251,164	$ 189,231
1855-Services	$ 3,067,877	$ 3,008,277	$ 59,600	$ 2,985,377	$ 22,900	$ 2,958,220	$ 27,157	$ 2,753,397	$ 204,823
1860-Meters	$ 827,581	$ 812,581	$ 15,000	$ 797,581	$ 15,000	$ 790,911	$ 6,670	$ 775,202	$ 15,710
1905-Land	$ 8,640	$ 8,640	$ -	$ 8,640	$ -	$ 8,640	$ -	$ 8,640	$ -
1908-Buildings and Fixtures	$ 1,020,234	$ 1,020,234	$ -	$ 1,020,234	$ -	$ 1,020,234	$ -	$ 1,020,234	$ -
1915-Office Furniture and Equipment	$ 98,052	$ 98,052	$ -	$ 98,611	$ (559)	$ 80,345	$ 18,2	$ 71,974	$ 8,371

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1920-Computer Equipment - Hardware	$ 172,301	$ 143,301	$ 29,000	$ 185,585	$ (42,284)	$ 159,845	$ 25,740	$ 177,898	$ (18,053)
1925-Computer Software	$ 306,082	$ 224,082	$ 82,000	$ 128,082	$ 96,000	$ 75,811	$ 52,270	$ 67,860	$ 7,952
1930-Transportation Equipment	$ 885,271	$ 840,271	$ 45,000	$ 840,271	$ -	$ 969,980	$ (129,709)	$ 639,078	$ 330,902
1935-Stores Equipment	$ 21,934	$ 20,934	$ 1,000	$ 19,934	$ 1,000	$ 19,934	$ -	$ 19,724	$ 211
1940-Tools, Shop and Garage Equipment	$ 71,541	$ 69,541	$ 2,000	$ 73,496	$ (3,955)	$ 69,543	$ 3,952	$ 41,904	$ 27,640
1945-Measurement and Testing Equipment	$ 44,145	$ 43,145	$ 1,000	$ 42,145	$ 1,000	$ 42,145	$ -	$ 41,282	$ 863
1950-Power Operated Equipment	$ 88,275	$ 88,275	$ -	$ 98,995	$ (10,720)	$ 98,995	$ -	$ 84,511	$ 14,484
1955-Communication Equipment	$ 31,305	$ 31,305	$ -	$ 31,305	$ -	$ 30,808	$ 497	$ 23,854	$ 6,954
1960-Miscellaneous Equipment	$ 11,962	$ 11,962	$ -	$ 9,462	$ 2,500	$ 9,462	$ -	$ 1,709	$ 7,753
1980-System Supervisory Equipment	$ 170,870	$ 170,870	$ -	$ 170,870	$ -	$ 170,870	$ -	$ 169,149	$ 1,721
1985-Sentinel Lighting Rental Units	$ 2,516	$ 2,516	$ -	$ 2,516	$ -	$ 2,516	$ -	$ 2,516	$ -
1995-Contributions and Grants - Credit	$ (960,491)	$ (960,491)	$ -	$ (960,491)	$ -	$ (1,007,466)	$ 46,975	$ (728,217)	$ (279,249)
TOTAL	$ 15,804,996	$ 14,989,396	$ 815,600	$ 14,581,313	$ 408,082	$ 14,260,661	$ 320,652	$ 12,978,928	$ 1,281,733

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Materiality/Variance Analysis on Gross Assets

The calculation of the materiality level as set out in the Filing Guidelines is those variances that exceed 1% of net fixed assets. The calculation of the Materiality Threshold on gross assets is shown in the following table:

	EDR – 2006	Actual – 2006	Actual – 2007	Bridge – 2008	Test – 2009
Gross Cost	$12,978,928	$14,260,661	$14,581,313	$14,989,396	$15,804,996
Accumulated Amortization	$ 5,885,084	$ 7,173,707	$ 7,619,796	$8,186,556	$8,906,433
Net Fixed Assets	$ 7,093,844	$ 7,086,954	$ 6,961,517	$ 6,802,840	$6,898,563
Percent	1%	1%	1%	1%	1%
Minimum Filing Threshold	$70,938	$70,870	$69,615	$68,028	$68,986

The Applicant has selected the lowest materiality threshold of $68,028 to allow for the most detailed review of gross asset changes. Those variances that have exceeded the materiality level and those variances that are under the 1% are explained as follows:

Historical Board Approved to Actual 2006

Actual ending balance for Capital Assets as at December 31, 2006 is $14,260,661 vs. the EDR Board Approved balance of $12,978,928. The variance, $1,281,733 is a combination of additions/retirements in 2006 and in 2005, and in part is due to the balance shown as 2006 EDR which is actually an averaging of the 2003 and 2004 Capital Asset balances.

Explanations of variances greater than 1% are set out as follows:

Acct # & Name	Year	Amount	Description of Addition
#1830 – Poles, Towers & Fixtures	2004	$ 7,953.24	Job 04-021 Installed a new 3 phase section of line between Queen St and Union St West, to improve system reliability
		$ 18,758.18	Job 04-020 – Upgraded hydro lines on Tower St in Fergus due to age of lines.
		$ 19,654.84	Job 04-064 – Replace existing substandard pole line on Kertland St from Mill St to Colborne St with 10 new 50 foot poles and 336 conductor to reduce line losses and improve safety. System reliability will be improved by creating a loop on the F1 and F3 feeders
		$ 8,949.24	Job 01-028 – Remove overhead lines and replace with underground lines for replacement of David St Bridge in Elora.
		$ 1,181.21	Job 04-052 – New services required on Woodside St as a result of road improvements

Acct # & Name	Year	Amount	Description of Addition
		$ 310.53	Job 04-051 - System improvement on feeders F4 and F6 Elora, to improve system reliability
		$ 822.07	Job 04-057 - Install new pole at 555 Glengarry Cres, Fergus.
		$ 957.00	Job 04-033 - New pole for construction at Community Centre
		$ 3,702.28	Job 04-001 - Remove overhead lines and replace with underground lines for replacement of David St Bridge in Elora.
		$ 707.95	Job 02-024 - The Township upgraded well #6 facility, in Fergus, which then required an installation upgrade in the electricity service.
		$ 1,877.54	Contributed Capital for 2004 – Township of Centre Wellington – 44 kV connection to the arena
		$ 397.91	Job 03-076 - New pole at Elora splash pad
		$ 1,563.23	Job 04-082 Replace two substandard poles and install new switches on F1 feeder on Colborne St between Chalmers and Queen St to improve switching options.
		$ 654.50	No job number - put new pole in Elora
	Total 2004	**$ 67,489.70**	
	2005	$ 13,326.98	Job 04-022- Upgraded Conductor on Mill St East in Elora from Geddes St to Kertland St- to improve system reliability
		$ (709.09)	Job 04-001 - Remove overhead lines and replace with underground lines for replacement of David St Bridge in Elora.
		$ 9,459.52	Job 05-056 – Replace substandard overhead system, both primary and secondary, on Churchill Cres, Fergus with new poles and conductors to improve safety and reliability
		$ 12,785.38	Job 05-052 – Replace substandard overhead system, both primary and secondary, on Highland Rd, Fergus with new poles and conductors to improve safety and reliability
	Total 2005	**$ 34,862.80**	
	2006	$ 5,276.07	Job 06-091 – Alter overhead line because of road improvements done on Forfar St, Fergus
		$ 452.20	Job 06-102 – Install new service at 595 Garafraxa St, Fergus
		$ 21,294.96	Job 06-071 – Replace 18 substandard poles and switches with new 50 foot poles and one new air break switch on St David St N from Parkside to Gordon St, Fergus to improve reliability
		$ 819.70	Job 06-081 – Replacement aging direct buried primary cable and (poletrans) transformer with new primary cable installed in ducts and pad mount transformers on Parkside Ave E, Fergus.
		$ 2,842.14	Job 06-049 – Alterations to existing overhead system to facilitate intersection improvements and road widening
		$ 1,023.45	Job 06-044 – 120 Union Street - new connection to infill lot
		$ 15,936.59	Job 06-027 – Replace substandard pole line on Elora St from Perth St to Guelph Rd. Install 8 50 foot poles and new 336 primary conductor. Install new spun secondary conductor all to improve system and reliability.
		$ 375.11	Job 04-022- Upgraded Conductor on Mill St East in Elora from Geddes St to Kertland St- to improve system reliability
		$ 1,356.45	Job 06-101 – Construct new line to connect the F1 feeder and the F2 feeder to improve system reliability between St Andrew St and South River Road
	Total 2006	**$ 49,376.67**	
#1830 – Poles, Towers & Fixtures	1/2 2004 and all 2005, 2006	**$ 117,984.32**	
#1835 –Overhead Conductors & Devices	2004	$ 5,167.39	Job 04-021 Installed a new 3 phase section of line between Queen St and Union St West, to improve system reliability

Acct # & Name	Year	Amount	Description of Addition
		$ 8,825.85	Job 04-020 – Upgraded hydro lines on Tower St in Fergus due to age of lines.
		$ (225.02)	Job 04-001 - Remove overhead lines and replace with underground lines for replacement of David St Bridge in Elora.
		$ 10,523.27	04-014 switch maintenance
		$ 7,049.49	04-075 - Change out old porcelain insulators with new polymer ones on Union St W and Allan St to improve safety and reliability
		$ 3,230.05	2004 Contributed Capital Aquicon Const
		$ 2,024.98	Job 04-052 – New services required on Woodside St as a result of road improvements
		$ 9,516.96	Job 04-051 - System improvement on feeders F4 and F6 Elora, to improve system reliability
		$ 23,618.92	Job 04-064 – Replace existing substation pole line on Kertland St from Mill St to Colborne St with 10 new 50 foot poles and 336 conductor to reduce line losses and improve safety. System reliability will be improved by creating a loop on the F1 and F3 feeders
		$ 2,105.64	Job 04-082 Replace two substandard poles and install new switches on F1 feeder on Colborne St between Chalmers and Queen St to improve switching options.
		$ 332.39	Job 02-024 - The Township upgraded well #6 facility, in Fergus, which then required an installation upgrade in the electricity service.
	Total 2004	**$ 72,169.92**	
	2005	$ 6,163.35	Job 05-056 – Replace substandard overhead system, both primary and secondary, on Churchill Cres, Fergus with new poles and conductors to improve safety and reliability
		$ 3,989.77	Job 05-052 – Replace substandard overhead system, both primary and secondary, on Highland Rd, Fergus with new poles and conductors to improve safety and reliability
		$ 196.72	Job 05-005 - Empty reels picked up
		$ 831.26	Job 05-063 - Douglas Cres Secondary conductor upgrade due to age
		$ 578.68	Job 05-057 - Remove primary overhead from backyard on Colquhoun St to eliminate safety hazard in backyards
		$ 79,805.58	Job 04-022- Upgraded Conductor on Mill St East in Elora from Geddes St to Kertland St- to improve system reliability
	Total 2005	**$ 91,565.36**	
	2006	$ 203.47	Job 06-091 – Alter overhead line because of road improvements done on Forfar St, Fergus
		$ 77.06	Job 06-081 – Replacement aging direct buried primary cable and (poletrans) transformer with new primary cable installed in ducts and padmount transformers on Parkside Ave E, Fergus.
		$ 18,574.01	Job 06-071 – Replace 18 substandard poles and switches with new 50 foot poles and one new air break switch on St David St N from Parkside to Gordon St, Fergus
		$ 7,157.60	Job 06-049 – Alterations to existing overhead system to facilitate intersection improvements and road widening
		$ 6,723.99	Job 06-027 – Replace substandard pole line on Elora St from Perth St to Guelph Rd. Install 8 50 foot poles and new 336 primary conductor. Install new spun secondary conductor all to improve safety and reliability
#1835 –Overhead Conductors & Devices	Total 2006	**$ 32,736.13**	
	1/2 2004 and all 2005, 2006	**$ 160,386.45**	

#1840 – Underground Conduit	2004	$47,255.31	Job 04-001 - Remove overhead lines and replace with underground lines for replacement of David St Bridge in Elora.

Acct # & Name	Year	Amount	Description of Addition
		$9,210.30	Conduit for BenNevis Phase 2 Subdivision
	Total 2004	**$56,465.61**	
	2005	$126.80	Job 05-071 – Reposition padmount from Tower St to Wellington St to remove from edge of roadway and sidewalk snowplow
		$116,996.88	Conduit for Mod-Aire and Keating phase 3 subdivision
	Total 2005	**$117,123.68**	
	2006	$20,678.98	Job 06-081 – Replace aging direct buried primary cable and (poletrans) transformer with new primary cable installed in ducts and padmount transformers on Parkside Ave E, Fergus.
		$4,110.98	Job 06-034 – Installed new switching cubicle to facilitate a loop feed connection for a new subdivision
		$54,303.00	Conduit for Ville Lora Downs North Phase 3 installation
	Total 2006	**$79,092.96**	
#1840 – Underground Conduit	1/2 2004 and all 2005 and 2006	**$224,449.45**	
#1845 – Underground Conductors and Devices	2004	$10,354.98	Underground conductors and devices for BenNevis phase 2 subdivision
		$331.04	Job 04-020 – Upgraded hydro lines on Tower St in Fergus due to age of lines.
		$19,130.34	Job 04-001 - Remove overhead lines and replace with underground lines for replacement of David St Bridge in Elora.
	Total 2004	**$29,816.36**	
	2005	$1,820.64	Job 05-071 – Reposition padmount from Tower St to Wellington St to remove from edge of roadway and sidewalk snowplow
		$69,739.55	Underground conductors and devices for Mod-Aire and Keating subdivision phase 3
	Total 2005	**$71,560.19**	
	2006	$124.48	Job 06-091 – Alter overhead line because of road improvements done on Forfar St, Fergus
		$23,704.95	Job 06-081 – Replacement aging direct buried primary cable and (poletrans) transformer with new primary cable installed in ducts and padmount transformers on Parkside Ave E, Fergus.
		$92,506.08	Underground conductors and devices for Down North phase 3 and Woodhill Gardens
	Total 2006	**$116,335.51**	
#1845 – Underground Conductors and Devices	1/2 2004 and all 2005 and 2006	**$202,803.88**	
#1850 – Line Transformers	2004	$19,803.92	Line transformer for BenNevis phase 1 and 2 and Arif Mian.
		$1,311.63	Labour and materials for transformers
	Total 2004	**$21,115.55**	
	2005	$7,303.11	Purchase 75 KVA 3-ph pad overhead transformer from Cooper Power Systems
		$125.83	Job 04-001 - Remove overhead lines and replace with underground lines for replacement of David St Bridge in Elora.
		$3,262.90	Labour and Burdens to install purchased transformers
		$38,701.76	Contributed Capital for Keating Phase 3, ModAire, Pizza Pizza and Keating subdivision.
	Total 2005	**$49,393.60**	
	2006	$1,913.81	Job 06-027 – Replace substandard pole line on Elora St from Perth St to Guelph Rd. Install 8 50 foot poles and new 336 primary conductor. Install new spun secondary conductor to improve safety and reliability.

Acct # & Name	Year	Amount	Description of Addition
		$13,743	Purchase 225 KVA 3-ph pole mount overhead transformer from Carte International. Part number 014T17ADWM
		$12,782.88	Purchase 300 KVA 3-ph pad mount overhead transformer from Carte International. Part number 014F19ADVK
		$7,418.52	Purchase 75 KVA 3-ph pad mount overhead transformer from Carte International. Part number 014F12ADVJ
		$30,800.52	Purchase 6 4KV and 1 75 KVA underground transformers from Copper Power Systems
		$17,215.20	Purchase 4 50 KVA 1-ph minipad transformer from Carte International
		$52,238.10	Line Transformer for Down North phase 3 and Woodhill Gardens
		($9,218.52)	Invoice #398 and #470 – Sale of Transformers – one to Orangeville Hydro and one to BE Pressure Supply
		$2,386.27	Labour, burdens and small materials used to install transformers
	Total 2006	**$129,279.78**	
#1850 – Line Transformers	1/2 2004 and all 2005 and 2006	**$189,231.16**	
#1855 – Services	2004	$11,833.10	Services for BenNevis phase 2 and Klompmaker
		$2,173.81	Job 04-001 - Remove overhead lines and replace with underground lines for replacement of David St Bridge in Elora.
		$324.36	Job 04-052 – New services required on Woodside St as a result of road improvements
		$976.55	04-026 - Remove primary overhead from backyard on Herrick St to eliminate safety hazard in backyards
		$935.66	Job 04-021 Installed a new 3 phase section of line between Queen St and Union St West, to improve system reliability
		$6,012.58	Job 04-020 – Upgraded hydro lines on Tower St in Fergus due to age of lines.
		$17,472.00	New services
		$624.45	Job 04-064 – Replace existing substation pole line on Kertland St from Mill St to Colborne St with 10 new 50 foot poles and 336 conductor to reduce line losses and improve safety. System reliability will be improved by creating a loop on the F1 and F3 feeders
		$11,954.70	Base Connection Refund
	Total 2004	**$52,307.21**	
	2005	$76,373.72	Services for Mod-Aire subdivision, Keating Phase 3, Pizza Pizza.
		$6,264.48	Job 04-001 - Remove overhead lines and replace with underground lines for replacement of David St Bridge in Elora.
		$1,918.06	Job 05-071 – Reposition padmount from Tower St to Wellington St to remove from edge of roadway and sidewalk snowplow
		$6,701.18	Job 05-052 – Replace substandard overhead system, both primary and secondary, on Highland Rd, Fergus with new poles and conductors to improve safety and reliability
		$4,146.59	Job 05-056 – Replace substandard overhead system, both primary and secondary, on Churchill Cres, Fergus with new poles and conductors to improve safety and reliability
		$4,125.95	Job 05-014 - The Township upgraded well #1 facility, in Fergus, which then required an installation upgrade in the electricity service.
		$10,440.00	New services added - no job numbers (underground)
		$1,538.41	Base Connection Refund
	Total 2005	**$111,508.39**	
	2006	$7,807.45	Job 06-027 – Reconstruction: new poles and conductor on Elora Street, Fergus due to age.
		$2,004.49	Job 06-025 – Extend secondary conductor to supply newly installed TV amplifier

Acct # & Name	Year	Amount	Description of Addition
		$258.92	Job 06-044 – 120 Union Street - new connection to infill lot
		$5,047.71	Job 06-049 – Alterations to existing overhead system to facilitate intersection improvements and road widening
		$0.00	
		$243.02	Job 06-077- 125 Union St - new connection
		$2,857.93	Job 06-101 – Construct new line to connect the F1 feeder and the F2 feeder to improve system reliability between St Andrew St and South River Road
		$254.66	Job 06-102 – Install new service at 595 Garafraxa St, Fergus
		$259.15	Job 06-107 – To connect Hydro One customer to our system due to new subdivision construction
		$45,071.13	Services for new subdivision
		$1,593.96	Base Connection Refund
		$1,762.67	Job 06-071 – Replace 18 substandard poles and switches with new 50 foot poles and one new air break switch on St David St N from Parkside to Gordon St, Fergus
	Total 2006	**$67,161.09**	
#1855 – Services	Total 2004	**$204,823.08**	
#1930 – Transportation Equipment	2004	$7,326.55	Bought 1994 GMC 3500 Dump truck
		$225,396.95	Purchase 2003 International Single Bucket truck
	Total 2004	**$232,723.50**	
	2005	($22,266.93)	Dispose of 1998 F150 truck
		($55,134)	Disposed of 1992 International
		$481.51	Modification to truck #5
	Total 2005	**($76,919.42)**	
	2006	$291,460.16	Purchased new 2007 International 7500 Digger truck
#1930 – Transportation Equipment	½ 2004 and Total 2005 and 2006	**$330,902.49**	
#1995 - Contributions and Grants	**2004**	($1,502)	Fergus Arena - Township of Centre Wellington
		($3,230)	Centre Wellington District High School - Aquicon Construction
		($24,954)	Ben Nevis Phase 2
		($352)	John Klompmaker
		$20,296	Fergus Mill Adjustment from 2003
		$31,783	Depreciation of Contributions and Grants
		($510)	Alif Mian - 600 Scotland St
	Total 2004	**$21,532**	
	2005	($150,706)	Mod-Aire Homes
		($38,048)	Harmony Trails Phase 3
		$1,915	Cherryhill Phase 2
		$7,893	Ville Lora Station Square
		($1,748)	Various Vendors
		($6,727)	Pizza Pizza - Luigi Gallo
		$35,952	Depreciation of Contributions and Grants
	Total 2005	**($151,469)**	
	2006	($155,316)	Ville Lora Station Square
		($1,003)	B Murray
		($2,058)	Ben Nevis - Gordon St
		($19,447)	Woodhill Gardens
		($4,061)	Damside Developments - Fergus Market

Acct # & Name	Year	Amount	Description of Addition
		$43,338	Depreciation of Contributions and Grants
	Total 2006	**($138,546)**	
#1995 - Contributions and Grants	1/2 2004 plus 2005 and 2006	**($279,249)**	

Variances Less Than 1%

Account variances greater than 1% have been explained above. Those additions with a variance of less than 1% represent miscellaneous additions to the USofA accounts as follows:

Acct # & Name	**Year**	**Amount**	**Description of Addition**
#1806 – Land Rights	**2005**	$1,126	Property Transfer
		$275	Part lot exemption fee
	Total 2005	**$1,401**	
	2006	$1,500	Hydro Easement by South River Road, Fergus
#1806 – Land Rights	**Total 2005 and 2006**	**$2,901**	
#1820 –Distribution Station Equipment	**2005**	$24,084.02	Upgrade WMP Fergus TS
		$27,657.00	Replace M3 Feeder in Fergus.
#1820 –Distribution Station Equipment	**Total 2005**	**$51,741.02**	
#1825 – Storage battery Equipment	**2005**	**$2,155**	Batteries for stations 1 and 2
#1860 - Meters	**2004**	($9,392.00)	This amount consists of the $50,634 adjustment on EDR Adj1 model and the averaging of the difference between 2003 and 2004 of $41,241.90 for a net difference of $9,392. The Balance in 1860 of the EDR model for 2004 includes the adjustment for Wholesale meters upgrade of $50,634.
	2005	$820.43	Labour and Burdens to install meters
		$10,832.79	Meters from Itron, Brooks Utility (test switch), Ekstrom (5 adapter forms) and Olameter (60 single phase meters)
	Total 2005	**$11,653.22**	
	2006	$6,850.17	Includes Meters from Elster and Young Utility.
		$4,060.80	Meters for new subdivision
		$2,537.49	Labour and burdens to install meters
	Total 2006	**$13,448.46**	
#1860 - Meters	**2004 + 2005 and 2006**	**$15,709.68**	
#1915 – Office Furniture and Equipment	**2004**	$858.03	Three new bookcases
	2005	$388.79	New bookcase
	2006	$4,150	New postage machine
		$481	New locking file cabinet
		$2,922	New postage meter
	Total 2006	$7,553	

Acct # & Name	Year	Amount	Description of Addition
#1915 – Office Furniture and Equipment	**Total ½ 2004 and all 2005 and 2006**	**$8,371.00**	
#1920 – Computer Equipment – Hardware	**2004**	$2,052.00	Purchased Cisco switch
		$570.24	APC from ITM
		($3,580.72)	Dispose of laptop
		$6,208.36	Purchase new computers
	Total 2004	**$5,249.88**	
	2005	$2,289	New computer for Accounts Payable
		$2,699	New computer for SCADA room
		($46,125)	Scrapped computer equipment that was fully depreciated
	Total 2005	**($41,137)**	
	2006	$2,766	Security Router
		$17,693	New computers – 2 laptops and 3 desktop computers and one laser jet printer
	Total 2006	**$20,459**	
#1920 – Computer Equipment – Hardware	**Total ½ 2004 and all of 2005 & 2006**	**($18,053.06)**	
#1925 – Computer Software	**2004**	$3,500	Bill Print
	2006	$1,342	Software for 2 new laptops
		$4,860	Software for Royal Bank application
	Total 2006	**$6,202**	
#1925 – Computer Software	**½ of 2004 and total from 2006**	**$7,952.00**	
#1935 – Stores Equipment	**2004**	$421.20	Industrial shelf for shop
	½ 2004	**$211**	
#1940 – Tools, shop and Garage Equipment	**2004**	$1,187.98	New power pruner
		$1,091.29	Quick cut saw with disc
	Total 2004	**$2,279.27**	
	2005	$3,480	18 volt crimping tool
		$604.80	Burndy Hand Hytool
		$661.98	Hood – orange
		$647.95	Stihl chainsaw 18” bar
		$2,532.34	Line hose
		$617.14	Hose
		$1,821.99	Yamaha generator
		$5,151.60	6707 Block, clevis ball
		$4,709.20	Mobile Mapper
	Total 2005	**$20,227**	
	2006	$3,484.48	Assembly of clevis ball 35,000 pounds from Timberland Equipment
		$500.14	Pliers, cutter head
		$419.98	Digital camera
		$1,868.58	Hastings shotgun stick and telescopic stick
	Total 2006	**$6,273**	

Acct # & Name	Year	Amount	Description of Addition
#1940 – Tools, shop and Garage Equipment	**½ 2004 and all 2005 & 2006**	**$27,640.00**	
#1945 – Measurement and Testing Equipment	**2006**	**$862.92**	Insulation multimeter
#1950 – Power Operated Equipment	**2005**	**$14,484**	For Reel Poleboss, brake spindle and a line truck winch adapter
#1955 – Communication Equipment	**2004**	$947.69	Radio and horn for truck #12
	2005	$2,921.40	Update office telephone system with voice mail and telephone extensions
		$3,558.92	New radio for truck #5, as well as new portable radios and a new speaker for the shop
	Total 2005	$6,480.32	
#1955 – Communication Equipment	**½ 2004 and all 2005**	**$6,954**	
#1960 – Miscellaneous Equipment	**2005**	$1,461.48	Install new drop box for customers to drop payments into
	2006	$3,267.70	Purchase defibulator
		$3,024	Security System outside shop
	Total 2006	$6,291.70	
#1960 – Miscellaneous Equipment	**Total 2005 and 2006**	**$7,753.10**	
#1980 – System Supervisory Equipment	**2004**	$3,442.10	Upgrade to software to SCADA system
	1/2 2004	**$ 1,721.05**	

2006 Actual to 2007 Actual

Actual ending balance for Capital Assets as at December 31, 2006 is $14,260,661 vs. Actual Capital Assets at December 31, 2007 of $14,581,313. The variance, $320,652 is a result of additions of $510,941 and retirements of $190,289 throughout the 2007 year.

Explanations of variances greater than the materiality level of $69,615 listed in Exhibit 2, Tab 2, Schedule 3, page 1 are as follows:

Acct # & Name	Year	Amount	Description of Addition
#1830 – Poles, Towers & Fixtures	**2007**	$42,133.81	Job 06-101 – Construct new line to connect the F1 feeder and the F2 feeder to improve system reliability between St Andrew St and South River Road

Acct # & Name	Year	Amount	Description of Addition
		$10,530.46	Job 06-064 – Line upgrade - new pole and conductor in preparation for new large load customer at Heritage River Retirement Home, Elora.
		$892.00	Job 07-091 – Replace substandard fuse cutouts with new solid cutouts, at 424 Union St W, Fergus
		$1,598.82	Job 07-083 Replace substandard secondary pole and reposition to road allowance in front of house. Reroute overhead secondary to new pole and onto stack at 49 Church St, Elora
		$1,990.16	Job 07-081 – Gartshore St – New pole - due to road widening
		$1,737.67	Job 07-067– Storm Damage 165 Garafraxa St, Fergus Pole Replacement
		$408.50	Job 07-060 Replace aging direct buried with new primary cable installed in ducts and replace two poletrans type transformers with one new padmount transformer on Albert St E, Fergus.
		$5,769.89	Job 07-056 Replace rotten pole and upgrade primary conductor on Herrick St and Hill St to improve safety and reduce line losses.
		$2,398.86	Job 07-055 – Replace two steel poles with wood on Colquhoun St, Fergus to improve safety
		$202.40	Job 07-048 Underground service – 81 McNab St, Elora
		$1,909.21	Job 07-038 – New service for new Bell underground exchange – Bridge St, Elora
		$1,656.95	Job 07-020 – Upgrade to 5 foot higher pole for additional clearance on Garafraxa St.
		$12,234.24	Job 07-018 - Replace substandard poles and switches with 7 new 50 foot poles and 3 new switches on Belsyde Ave.
		$1,464.22	Job 07-13 - New poles – John St and Colborne St, Elora.
#1830 – Poles, Towers & Fixtures	**Total 2007**	**$84,927.19**	
#1850 – Line Transformers	**2007**	$1,154.77	Job 07-060 Replace aging direct buried with new primary cable installed in ducts and replace two poletrans type transformers with one new padmount transformer on Albert St E, Fergus.
		$7,076.16	Purchase 112 KVA 3-ph padmount overhead transformer from Carte International. Part number 014T14AECN
		$18,554.40	Purchase 300 KVA 3-ph Pad Mount overhead transformer from Lakeport Power. S/N 22611:001
		$21,892.68	Purchase 500 KVA 3-ph Pad Mount overhead transformer from Carte International. Part number 014F21AE9E
		$12,150	Purchase 150 KVA 3-ph pad mount overhead transformer from Lakeport Power. S/N C-27078-1
		$4,627.80	Purchase 50 KVA a-ph pad mount overhead transformer from Lakeport Power
		$9,255.60	Purchase 2 50KVA 1-ph pad mount underground transformers from Lakeport Power
		$12,150	Purchase 150KVA 3-ph pad mount underground transformer from Lakeport Power
		$506.05	Material purchases to install transformers
#1850 – Line Transformers	**Total 2007**	**$87,367.46**	
#1930 – Transportation Equipment	**2007**	($7,326.55)	Disposed of 1994 F150 dump truck
		($18,538.08)	Disposed of 2000 F150 4x2 truck
		($164,424.14)	Disposed of 1994 Bucket Truck with chassis and bucket
		$60,579.55	Purchase 2007 Dodge Ram 3500 4x4 Dump truck
#1930 – Transportation Equipment	**Total 2007**	**($129,709.22)**	

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Variance Less Than 1%

Those additions with a variance of less than 1% represent miscellaneous additions to the USofA accounts as follows:

Acct # & Name	Year	Amount	Description of Addition
#1806 – Land Rights	**2007**	$759.50	Easements for Cassie and Kooiman
		$2,346.50	Legal boundary survey and plan
		$275	Property Transfer Elora
#1806 – Land Rights	**Total 2007**	**$3,381.00**	
#1835 –Overhead Conductors & Devices	**2007**	$ 2,210.31	Job 07-13 - New poles – John St and Colborne St, Elora.
		$ 7,857.88	07-018 - Replace substandard poles and switches with 7 new 50 foot poles and 3 new switches on Belsyde Ave.
		$ 5,228.67	Job 07-056 Replace rotten pole and upgrade primary conductor on Herrick St and Hill St to improve safety and reduce line losses.
		$ 460.65	Job 07-060 Replace aging direct buried with new primary cable installed in ducts and replace two poletrans type transformers with one new padmount transformer on Albert St E, Fergus.
		$ 112.23	Job 07-067– Storm Damage 165 Garafraxa St, Fergus Pole Replacement
		$ 7,308.08	Job 07-091 – Replace substandard fuse cutouts with new solid cutouts, at 424 Union St W, Fergus
		$ 186.14	Job 07-081 – Gartshore St – New pole - due to road widening
		$ 28,816.15	Job 06-101 – Construct new line to connect the F1 feeder and the F2 feeder to improve system reliability between St Andrew St and South River Road
		$ 10,881.28	Job 06-064 – Line upgrade - new pole and conductor in preparation for new large load customer at Heritage River Retirement Home, Elora.
		$ 496.11	Job 06-081 – Replacement aging direct buried primary cable and (poletrans) transformer with new primary cable installed in ducts and padmount transformers on Parkside Ave E, Fergus.
		$1,087.50	Job 06-53 - Line alterations to allow new primary connection to Fergus Motel
#1835 –Overhead Conductors & Devices	**Total 2007**	**$ 64,645.00**	
#1840 – Underground Conduit	**2007**	$ 17,480.00	Job 07-060 Replace aging direct buried with new primary cable installed in ducts and replace two poletrans type transformers with one new padmount transformer on Albert St E, Fergus.
		$ 1,275.00	Job 06-101 – Construct new line to connect the F1 feeder and the F2 feeder to improve system reliability between St Andrew St and South River Road
#1840 – Underground Conduit	**Total 2007**	**$ 18,755.00**	
#1845 – Underground Conductors and Devices	**2007**	$ 7,496.77	Job 07-060 Replace aging direct buried with new primary cable installed in ducts and replace two poletrans type transformers with one new padmount transformer on Albert St E, Fergus.
		$ 2,262.23	Job 06-081 – Parkside Ave. Poletrans Replacement: due to cables and transformers being old

Acct # & Name	Year	Amount	Description of Addition
#1845 – Underground Conductors and Devices	Total 2007	**$ 9,759.00**	
#1855 – Services	**2007**	$ 1,683.20	07-018 - Replace substandard poles and switches with 7 new 50 foot poles and 3 new switches on Belsyde Ave.
		$ 1,721.88	Job 07-059 - New pole installed on Bridge St in Elora
		$ 1,887.96	Job 07-038 – New service for new Bell underground exchange – Bridge St, Elora
		$ 1,003.84	Job 07-048 Underground service – 81 McNab St, Elora
		$ 128.07	Job 07-054 Relocate meter base at 23 Elkin Court, Fergus
		$ 1,263.71	Job 07-055 – Replace two steel poles with wood on Colquhoun St, Fergus to improve safety
		$ 951.33	Job 07-060 Replace aging direct buried with new primary cable installed in ducts and replace two poletrans type transformers with one new padmount transformer on Albert St E, Fergus.
		$ 729.95	Job 07-083 Replace substandard secondary pole and reposition to road allowance in front of house. Reroute overhead secondary to new pole and onto stack at 49 Church St, Elora
		$ 470.22	Job 07-091 – Replace substandard fuse cutouts with new solid cutouts, at 424 Union St W, Fergus
		$ 320.16	Job 07-026 - Reposition pole 230 Prince's St Fergus
		$ 317.80	Job 06-101 – Construct new line to connect the F1 feeder and the F2 feeder to improve system reliability between St Andrew St and South River Road
		$ 4,283.61	Job 06-064 – Line upgrade - new pole and conductor in preparation for new large load customer at Heritage River Retirement Home, Elora.
		$ 12,395.27	New customers from 2007
#1855 – Services	**Total 2007**	**$ 27,157.00**	
#1860 - Meters	**2007**	$ 343.00	Meters reverified
		$ 3,446.00	Elster 16 meters
		$ 2,881.00	Itron
#1860 - Meters	**Total 2007**	**$ 6,670.00**	
#1915 – Office Furniture and Equipment	**2007**	$1,134	Canon fax machine
		$15,138.36	New pro folder/inserter mail machine
		$1,993.59	New brown leather chairs for office
#1915 – Office Furniture and Equipment	**Total 2007**	**$18,265.95**	
#1920 – Computer Equipment - Hardware	**2007**	$1,154.22	CPU Tower enclosure with thermometer– to reduce noise coming from server
		$12,723.15	New server and installation (DC01Server)
		$5,581.36	New server and installation (DC02 Server)
		$3,707.64	New computer and monitor for SCADA room
		$2,573.21	New laptop for trucks
#1920 – Computer Equipment - Hardware	**Total 2007**	**$25,740**	
#1925 – Computer Software	**2007**	$55,270.32	Conversion from Harris PUBS to Harris Northstar version 6

Acct # & Name	Year	Amount	Description of Addition
#1940 – Tools, shop and Garage Equipment	**2007**	$1,339.18	Impact Torq Hydraulic Drill
#1940 – Tools, shop and Garage Equipment	**Total 2007**	**$3,952.30**	
#1955 – Communication Equipment	**2007**	$497	Polycom telephone for Board Room
#1995 - Contributions and Grants	2007	$46,975	Depreciation of Contributions and Grants

Historical Actual to Bridge – 2007 Actual to 2008 Bridge

Actual ending balance for Capital Assets as at December 31, 2007 is $14,581,313 vs. Budgeted Capital Assets at December 31, 2008 of $14,989,396. The variance is a result of additions and/or retirements throughout 2008 year.

Explanations of variances greater than the materiality level of $67,927 listed in the table in Exhibit 2, Tab 2, Schedule 3 page 1 are as follows:

Acct # & Name	Year	Amount	Description of Addition
#1830 – Poles, Towers & Fixtures	**2008**	$ 12,730.47	Install 3 phase connection for commercial property on Mill St Elora
		$ 18,163.08	New pole line on new road into industrial lands north of Glengarry
		$ 28,595.70	Highway 6 and McQueen Blvd - new concrete poles for 4 kV and 44 kV as well as new UG primary under McQueen to loop feed padswitch
		$ 11,210.75	Reframe poles as required in order to upgrade conductor and to improve reliability
#1830 – Poles, Towers & Fixtures	**Total 2008**	**$ 70,700.00**	
#1835 –Overhead Conductors & Devices	**2008**	$13,101.62	Install 3 phase connection for commercial property on Mill St Elora
		$19,534.23	New pole line on new road into industrial lands north of Glengarry
		$24,697.31	Highway 6 and McQueen Blvd - new concrete poles for 4 kV and 44 kV as well as new UG primary under McQueen to loop feed padswitch
		$24,966.85	Reframe poles as required in order to upgrade conductor and eliminate a newly created bottleneck
#1835 –Overhead Conductors & Devices	**Total 2008**	**$82,300.00**	
#1850 – Line Transformers	**2008**	$18,000.00	Install 3 phase connection for commercial property on Mill St Elora
		$129,000.00	New padmount transformers of various sizes

Acct # & Name	Year	Amount	Description of Addition
	Total 2008	**$147,000.00**	
#1860- Meters	**2008**	**$15,000.00**	500 hours related to fixing meter bases and upgrades to three elements and switching out meters that Measurement Canada will not allow the Applicant to postpone
#1925 – Computer Software	**2008**	$45,000	File Nexus program, allow The Applicant to go paperless and has capability for PDF search
		$8,000	Cognos software program, allows The Applicant to create their own reports
		$43,000	Going from Harris Fins to Harris Cayenta for financials, and work orders, M-Care, e-care
	Total 2008	**$96,000**	

Variances Less Than 1%

Those additions with a variance of less than 1% represent miscellaneous additions to the USofA accounts as follows:

Acct # & Name	Year	Amount	Description of Addition
#1806 – Land Rights	**2008**	$4,000	Easement at Price Chopper for down guys. Will be getting an easement from the owner re the OH line to customer owned transformer
#1840 – Underground Conduit	**2008**	$6,700	Highway 6 and McQueen Blvd - new concrete poles for 4 kv and 44 kV as well as new UG primary under McQueen to loop feed pad switch
#1845 – Underground Conductors and Devices	**2008**	$16,500	Highway 6 and McQueen Blvd - new concrete poles for 4 kv and 44 kV as well as new UG primary under McQueen to loop feed pad switch
#1855 – Services	**2008**	$22,900.00	125 possible new connections
	Total 2008	**$22,900.00**	
#1915 – Office Furniture and Equipment	**2008**	($20,559.06)	Disposed of used and fully depreciated assets such as chairs, postage meter, fax machine, photocopier
		$20,000	New tile floor for office
	Total 2008	($559)	
#1920 – Computer Equipment - Hardware	**2008**	$10,000	3 new desktop computers – Cashier, Admin Assistant and Financial Administrator
		$3,000	Colour duplex Laser printer and color desktop printer
		($55,284)	Wrote off assets that were disposed in 2008. Includes a number of computers and monitors, as well as a printer
	Total 2008	($42,284)	
#1935 – Stores Equipment	**2008**	$1,000	Purchase new stores equipment as equipment becomes obsolete
#1940 – Tools, shop and Garage Equipment	**2008**	($17,955)	Write off assets that were fully depreciated and disposed of includes pressure washer, 3500 Watt Generator, 12” cut off saw, Hydraulic hammer drill, Hex die, chain saws and a gas drill
		$8,000	Pressure Washer and Extractor hood over power washer
		$2,000	Shotgun switch sticks
		$4,000	Battery operator cutters

Acct # & Name	Year	Amount	Description of Addition
	Total 2008	**($3,955)**	
#1945 – Measurement and Testing Equipment	**2008**	$1,000	Meter test equipment – if required
#1950 – Power Operated Equipment	**2008**	($10,720)	Disposed of brush chipper and diesel Generator, both fully depreciated-
#1960 – Miscellaneous Equipment	**2008**	$2,500	To possibly replace a piece of existing equipment

2008 Bridge Year to 2009 Test Year

Budgeted ending balance for Capital Assets as at December 31, 2008 is $14,989,396 vs. Budgeted Capital Assets at December 31, 2009 of $15,759,996.

Explanations of variances greater than the materiality level of $68,543 listed in the table in Exhibit 2 Tab 2 Schedule 3, page 1 are as follows:

Acct # & Name	Year	Amount	Description of Addition
#1830 – Poles, Towers & Fixtures	**2009**	$43,594.38	Job 09-001 - Reconstruct Belsyde Ave from St David St to Scotland St. Install new 50' poles, upgrade conductor as required, install new polemount transformers and upgrade secondary conductor. Section of line on Sctoland St from St Andrew St to Belsyde Ave. Instal 50 foot poles. Install 44kv circuit to create a tie on the 44 kv for improved reliability. Upgrade 44 kv conductors. Install replacement transformers to improve reliability.
		$66,905.62	Job 09-002 - Reconstruct Scotland St under 44 kV, upgrade 4 KV conductor, install new section of 44kv to create a tie, install new polemount transformers, poles and secondary conductor
	Total 2009	**$110,500.00**	
#1835 – Overhead Conductors & Devices	**2009**	$25,939.96	Job 09-001 - Reconstruct Belsyde Ave from St David St to Scotland St. Install new 50' poles, upgrade conductor as required, install new polemount transformers and upgrade secondary conductor
		$110,360.04	Job 09-002 - Reconstruct Scotland St under 44 kV, upgrade 4 KV conductor, install new section of 44kv to create a tie, install new polemount transformers, poles and secondary conductor
	Total 2009	**$136,300.00**	
#1850 – Line Transformers	**2009**	$31,148.42	Job 09-001 - Reconstruct Belsyde Ave from St David St to Scotland St. Install new 50' poles, upgrade conductor as required, install new polemount transformers and upgrade secondary conductor
		$16,117.59	Job 09-002 - Reconstruct Scotland St under 44 kV, upgrade 4 KV conductor, install new section of 44kv to create a tie, install new polemount transformers, poles and secondary conductor
		$75,000.00	Transformers in preparation for 194 lot Eastwood Subdivision
		$183,733.99	Transformers for stock and replacement of existing ones in use because Applicant's stock of transformers is depleted.

Acct # & Name	Year	Amount	Description of Addition
	Total 2009	**$306,000.00**	
#1925 – Computer Software	**2009**	$82,000	Phase 2 of implementation of Cayenta Financials.

Variances Less Than 1%

Account variances greater than 1% have been explained above. Those additions with a variance of less than 1% represent miscellaneous additions to the USofA accounts as follows:

Acct # & Name	Year	Amount	Description of Addition
#1806 – Land Rights	**2009**	$4,000	Easements related to Belsyde Ave/ Scotland St / Eastwood Subdivisions
#1840 – Underground Conduit	**2009**	$5,000	Ducts to be installed under the road when Township of Centre Wellington completes planned road improvements
#1845 – Underground Conductors and Devices	**2009**	$ 19,200.00	Underground conductors and devices for 194 lot Eastwood Subdivision
#1855 – Services	**2009**	$11,470.47	Job 09-001 - Reconstruct Belsyde Ave from St David St to Scotland St. Install new 50' poles, upgrade conductor as required, install new polemount transformers and upgrade secondary conductor
		$24,376.33	Job 09-002 - Reconstruct Scotland St under 44 kV, upgrade 4 KV conductor, install new section of 44kv to create a tie, install new polemount transformers, poles and secondary conductor
		$23,753.20	Connection of new lots in Eastwood subdivision
#1855 – Services	**Total 2009**	$59,600.00	
#1860 – Meters	**2009**	$15,000	Purchase meters to replace existing one due to age
#1920 – Computer Equipment - Hardware	**2009**	$29,000	Includes two new computers for billing clerk and IESO computer, 2 new servers, new UPS power supply and one Laserjet 9050 printer
#1930 – Transportation Equipment	**2009**	$45,000	Smaller pickup truck replacement for the line foreman
#1935 – Stores Equipment	**2009**	$1,000	To replace or install new shelving
#1940 – Tools, shop and Garage Equipment	**2009**	$2,000	Tool replacement as required

Acct # & Name	Year	Amount	Description of Addition
#1945 – Measurement and Testing Equipment	**2009**	$1,000	Meter testing equipment – if required

Accumulated Depreciation Table

Accumulated Depreciation Table	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2006 Actual	2007 Actual	Variance from 2006 Actual	2007 Actual	2008 Bridge	Variance from 2007 Actual	2008 Bridge	2009 Test	Variance from 2008 Bridge
	($'s)	($'s)		($'s)	($'s)		($'s)	($'s)		($'s)	($'s)	
Land and Buildings												
1806-Land Rights-Depreciation	(1,712)	(2,991)	1,279	(2,991)	(3,562)	571	(3,562)	(4,216)	654	(4,216)	(4,950)	734
1808-Buildings and Fixtures-Depreciation	(1,806)	(1,954)	148	(1,954)	(2,013)	59	(2,013)	(2,072)	59	(2,072)	(2,131)	59
Sub-Total-Land and Buildings	**(3,518)**	**(4,944)**	**1,426**	**(4,944)**	**(5,574)**	**630**	**(5,574)**	**(6,287)**	**713**	**(6,287)**	**(7,080)**	**793**
Distribution Station												
1820-Distribution Station Equipment - Normally Primary below 50 kV-Depreciation	(588,572)	(677,659)	89,087	(677,659)	(712,736)	35,077	(712,736)	(747,813)	35,077	(747,813)	(782,890)	35,077
Sub-Total-DS	**(588,572)**	**(677,659)**	**89,087**	**(677,659)**	**(712,736)**	**35,077**	**(712,736)**	**(747,813)**	**35,077**	**(747,813)**	**(782,890)**	**35,077**
Poles and Wires												
1830-Poles, Towers and Fixtures-Depreciation	(502,127)	(618,518)	116,392	(618,518)	(667,805)	49,286	(667,805)	(718,495)	50,690	(718,495)	(772,263)	53,768
1835-Overhead Conductors and Devices-Depreciation	(325,827)	(415,385)	89,557	(415,385)	(454,480)	39,095	(454,480)	(495,444)	40,964	(495,444)	(540,437)	44,993
1840-Underground Conduit-Depreciation	(316,639)	(417,515)	100,876	(417,515)	(464,201)	46,686	(464,201)	(511,393)	47,192	(511,393)	(558,718)	47,325
1845-Underground Conductors and Devices-Depreciation	(522,809)	(661,635)	138,826	(661,635)	(723,723)	62,088	(723,723)	(786,332)	62,609	(786,332)	(849,477)	63,145

Sub-Total-Poles and Wires	**(1,667,402)**	**(2,113,053)**	**445,651**	**(2,113,053)**	**(2,310,208)**	**197,155**	**(2,310,208)**	**(2,511,664)**	**201,456**	**(2,511,664)**	**(2,720,895)**	**209,231**
Line Transformers												
1850-Line Transformers-Depreciation	(1,022,086)	(1,223,376)	201,290	(1,223,376)	(1,312,083)	88,707	(1,312,083)	(1,405,468)	93,385	(1,405,468)	(1,507,899)	102,431
Sub-Total-Line Transformers	**(1,022,086)**	**(1,223,376)**	**201,290**	**(1,223,376)**	**(1,312,083)**	**88,707**	**(1,312,083)**	**(1,405,468)**	**93,385**	**(1,405,468)**	**(1,507,899)**	**102,431**
Services and Meters												
1855-Services-Depreciation	(1,176,782)	(1,453,772)	276,990	(1,453,772)	(1,570,355)	116,584	(1,570,355)	(1,687,399)	117,044	(1,687,399)	(1,805,562)	118,163
1860-Meters-Depreciation	(371,796)	(435,201)	63,405	(435,201)	(461,604)	26,403	(461,604)	(488,443)	26,839	(488,443)	(515,883)	27,439
Sub-Total-Services and Meters	**(1,548,578)**	**(1,888,972)**	**340,394**	**(1,888,972)**	**(2,031,959)**	**142,987**	**(2,031,959)**	**(2,175,843)**	**143,884**	**(2,175,843)**	**(2,321,445)**	**145,602**
General Plant												
1908-Buildings and Fixtures-Depreciation	(135,886)	(190,434)	54,548	(190,434)	(212,253)	21,819	(212,253)	(234,072)	21,819	(234,072)	(255,891)	21,819
1910-Leasehold Improvements-Depreciation			-			-			-			-
Sub-Total-General Plant	**(135,886)**	**(190,434)**	**54,548**	**(190,434)**	**(212,253)**	**21,819**	**(212,253)**	**(234,072)**	**21,819**	**(234,072)**	**(255,891)**	**21,819**
IT Assets												
1920-Computer Equipment - Hardware-Depreciation	(150,928)	(138,758)	(12,170)	(138,758)	(153,075)	14,317	(153,075)	(116,190)	(36,885)	(116,190)	(137,344)	21,154
1925-Computer Software-Depreciation	(61,380)	(72,128)	10,748	(72,128)	(83,489)	11,361	(83,489)	(117,947)	34,458	(117,947)	(181,037)	63,091
Sub-Total-IT Assets	**(212,308)**	**(210,886)**	**(1,422)**	**(210,886)**	**(236,563)**	**25,678**	**(236,563)**	**(234,136)**	**(2,427)**	**(234,136)**	**(318,381)**	**84,245**
Equipment												
1915-Office Furniture and Equipment-Depreciation	(40,060)	(56,119)	16,059	(56,119)	(63,032)	6,913	(63,032)	(50,737)	(12,295)	(50,737)	(57,275)	6,538

1930-Transportation Equipment-Depreciation	(487,252)	(533,899)	46,647	(533,899)	(420,843)	(113,056)	(420,843)	(497,591)	76,748	(497,591)	(578,839)	81,248
1935-Stores Equipment-Depreciation	(13,431)	(17,798)	4,367	(17,798)	(18,653)	856	(18,653)	(18,998)	345	(18,998)	(19,443)	445
1940-Tools, Shop and Garage Equipment-Depreciation	(28,182)	(37,949)	9,767	(37,949)	(42,568)	4,619	(42,568)	(29,799)	(12,769)	(29,799)	(35,784)	5,986
1945-Measurement and Testing Equipment-Depreciation	(20,381)	(28,049)	7,668	(28,049)	(31,185)	3,136	(31,185)	(34,184)	2,999	(34,184)	(36,982)	2,798
1950-Power Operated Equipment-Depreciation	(58,833)	(77,600)	18,767	(77,600)	(85,830)	8,230	(85,830)	(80,128)	(5,701)	(80,128)	(81,938)	1,810
1955-Communication Equipment-Depreciation	(10,092)	(16,889)	6,797	(16,889)	(19,900)	3,011	(19,900)	(22,936)	3,036	(22,936)	(25,087)	2,151
1960-Miscellaneous Equipment-Depreciation	(685)	(2,422)	1,736	(2,422)	(4,193)	1,771	(4,193)	(6,129)	1,936	(6,129)	(7,730)	1,601
Sub-Total-Equipment	**(658,916)**	**(770,723)**	**111,807**	**(770,723)**	**(686,203)**	**(84,520)**	**(686,203)**	**(740,502)**	**54,299**	**(740,502)**	**(843,078)**	**102,577**
Other Distribution Assets												
1825-Storage Battery Equipment-Depreciation	-	(647)	647	(647)	(1,078)	431	(1,078)	(1,509)	431	(1,509)	(1,940)	431
1980-System Supervisory Equipment-Depreciation	(45,303)	(90,498)	45,195	(90,498)	(108,623)	18,125	(108,623)	(126,747)	18,125	(126,747)	(144,419)	17,672
1985-Sentinel Lighting Rental Units-Depreciation	(2,516)	(2,516)	-	(2,516)	(2,516)	-	(2,516)	(2,516)	-	(2,516)	(2,516)	-
Sub-Total-Other Distribution Assets	**(47,819)**	**(93,660)**	**45,842**	**(93,660)**	**(112,216)**	**18,556**	**(112,216)**	**(130,772)**	**18,556**	**(130,772)**	**(148,875)**	**18,103**
ACCUMULATED DEPRICIATION TOTAL	**(5,885,084)**	**(7,173,707)**	**1,288,623**	**(7,173,707)**	**(7,619,796)**	**446,089**	**(7,619,796)**	**(8,186,556)**	**566,761**	**(8,186,556)**	**(8,906,434)**	**719,877**

Materiality and Variance Analysis on Accumulated Amortization

The calculation of the Materiality Threshold on Gross Assets is shown in the following table:

	EDR – 2006	Actual - 2006	Actual – 2007	Bridge – 2008	Test - 2009
Gross Cost	$12,978,928	$14,260,661	$14,581,313	$14,989,396	$15,804,996
2105 - Accumulated Amortization	$ 5,885,084	$ 7,173,707	$ 7,619,796	$8,186,556	$8,906,433
Net Fixed Assets	$ 7,093,844	$ 7,086,954	$ 6,961,517	$ 6,802,840	$6,898,563
Percent	1%	1%	1%	1%	1%
Threshold	$70,938	$70,869	$69,615	$68,028	$68,986

The Applicant has selected the lowest materiality threshold of $68,028 to allow for the most detailed review of Accumulated Depreciation. A summary of each account is listed below as the account 2105 as a whole has a variance greater than one percent.

Actual 2006 to 2006 EDR Historical Board Approved

Description	2006 Actual	2006 EDR	Variance
Accumulated Amortization	$7,173,707	$7,885,084	$1,288,623
Cost Drivers:			
2006 EDR Averaging			$289,250.22
2005/2006 Amortization Expense			$1,123,913
Acct #1920 – Computer Equipment - Hardware			-$46,124
Acct #1930 – Vehicle – Truck Disposal			-$77,014
Unexplained Variance			$0

The actual ending balance of accumulated amortization as at December 31, 2006 is $7,173,707 vs. the 2006 EDR ending balance of $5,885,084. The variance, $1,288,623 is a combination of retirements in 2005, actual amortization expense for the years 2005 and 2006, along with the averaging of the 2003 and 2004 accumulated amortization balances in the 2006 EDR. The 2006 EDR amounts were determined by using an average of the 2003 and 2004 balances, which thereby reduced the actual amount in this account as at the end of 2004.

Explanation:

The 2006 Board Approved EDR balance was generated in the EDR filing based on an averaging of 2003 and 2004 balances which is $289,250 less than the 2004 actual balance. Amortization Expense for the years 2005 and 2006 totaled $1,123,913 (2005 = $530,911; 2006 = $593,002.) The 2005 and 2006 amortization expense results from the amortization expense for assets in-service prior to the current year plus ½ year amortization expense on assets declared in-service in the year. Assets disposed of in the current year result in a decrease to the accumulated amortization account by removing the accumulated amortization for that asset. In 2005 Centre Wellington Hydro disposed of a truck and computer hardware amounting to $77,014 and $46,124.

2007 Actual to 2006 Actual

Description	2007 Actual	2006 Actual	Variance
Accumulated Amortization	$7,619,796	$7,173,707	$446,089
Cost Drivers:			
2007 Amortization Expense			$511,313
Acct #1930 – Vehicle – Truck Disposal			-$190,289
Acct #1995 – Contributions & Grants			$46,976
Acct #1930 – Transportation and #1935 – Stores Equip. Depreciation Expense goes to Acct. 9070 and 9040.			$78,089
Unexplained Variance			$0

Explanation:

Amortization Expense for the year 2007 totaled $511,313 which is an incease over 2006 levels ($473,724) of $37,588. The 2007 amortization expense results from the amortization expense for assets in-service prior to the current year plus ½ year amortization expense on assets declared in-service in the year. Assets disposed of in the current year result in a decrease to the accumulated amortization account by removing the accumulated amortization for that asset and in 2007 the accumulated amortization on one truck disposal was removed from Account #1930 Transportation Equipment in the amount of $190,289. The balance of the variance of $46,976 is a reduction to Amortization Expense as a result of the amortization of Contributions and Grants.

2008 Bridge Year to 2007 Actual

Description	2008 Bridge Year	2007 Actual	Variance
Accumulated Amortization	$8,186,556	$7,619,796	$566,760
Cost Drivers:			
2008 Amortization Expense			$594,185
Acct #1915 – Office Furniture Disposal			-$20,559
Acct #1920 – Computer Equipment hardware – Disposal			-$55,284
Acct #1940 – Tools, Shop and Garage Equipment			-$17,955
Acct #1950 – Power Operated Equipment			-$10,720
Acct #1930 – Transportation and #1935 – Stores Equip. Depreciation Expense goes to Acct. 9070 and 9040.			$77,093
Unexplained Variance			$0

Explanation:

Projected Amortization Expense for the year 2008 is $594,185 which is an increase over 2007 levels ($511,313) of $82,872. The 2008 amortization expense results from the amortization expense for assets in-service prior to the current year plus ½ year amortization expense on assets declared in-service in the year. Assets disposed of in the current year result in a decrease to the accumulated amortization account by removing the accumulated amortization for that asset and in 2008. In 2008 we project to dispose of Office Furniture, $20,559; Computer Equipment Hardware, $55,284; Tools, Shop and Garage Equipment, $17,955; and Power Operated Equipment $10,720

2009 Test Year to 2008 Bridge Year

Description	2009 Test Year	2008 Bridge Year	Variance
Accumulated Amortization	$8,906,433	$8,186,556	$719,877
Cost Drivers:			
2009 Amortization Expense			$638,185
Transportation and Stores Depreciation Expense			$81,693
Unexplained Variance			0.00

Explanation:

Projected Amortization Expense for the year 2009 is $638,185 which is an increase over 2008 levels ($594,185) of $44,000. The 2009 amortization expense results from the amortization expense for assets in-service prior to the current year plus ½ year amortization expense on assets declared in-service in the year.

Capital Plan

Capital Plan by Project

Materiality Analysis on Capital Additions

	EDR – 2006	Actual – 2006	Actual – 2007	Bridge – 2008	Test – 2009
Gross Cost	$12,978,928	$14,260,661	$14,581,313	$14,989,396	$15,759,996
Accumulated Amortization	$ 5,885,084	$ 7,173,707	$ 7,619,796	$8,186,556	$8,906,433
Net Fixed Assets	$ 7,093,844	$ 7,086,954	$ 6,961,517	$ 6,802,840	$6,853,563
Percent	1%	1%	1%	1%	1%
Minimum Filing Threshold	$70,938	$70,870	$69,615	$68,028	$68,535
Centre Wellington Hydro Threshold	$25,000	$25,000	$25,000	$25,000	$25,000

The Applicant has selected a materiality threshold of $25,000 to allow for a more detailed review of capital additions. Costing of each of these capital projects is broken down by key element.

The following section of the Application is a breakdown of major capital projects for 2006 and 2007, projected capital projects for 2008 Bridge Year and for 2009 Test Year. Details for each capital project exceeding the materiality threshold as prescribed in the filing guidelines are presented.

Some projects obtain their transformers from the pool of transformers in stock, while other transformers are purchased specifically for each project.

2006 Year

Total capital additions for the 2006 year were $689,485.79. Those Projects exceeding the materiality threshold of $25,000 are as follows:

Project Description: Job #06-027

06-027	1830	$ 15,936.59	Replace substandard pole line on Elora St from Perth St to Guelph Rd. Install 8 50 foot poles and new 336 primary conductor. Install new spun secondary conductor.
	1835	$ 6,723.99	
	1850	$ 1,913.81	
	1855	$ 7,807.45	
Total Job Cost		**$ 32,381.84**	

Need: Poles were very old (approximately from 1950's,) 35 foot poles with transformers hanging from arms. Primary conductor was #6 solid copper on all three phases. Secondary conductor was 1/0 copper open buss and did not have adequate clearance.

Scope: Install 8 fifty foot poles with Hydro One Circuit to remain on top of pole. Install 1 phase only of 336 conductor for primary. Install new secondary 3/0 spun triplex. Install all new #2 triplex services. Install replacement transformers.

Project Start Date: Mid April 2006

Project Completion Date: August 15, 2006

Project Description: Job #06-071

06-071	1830	$ 21,294.96	Replace 18 substandard poles and switches with new 50 foot poles and one new air break switch on St David St N from Parkside to Gordon St, Fergus
	1835	$ 18,574.01	
	1855	$ 1,762.67	
Total Job Cost		**$ 41,631.64**	

Need: Poles were old 35 foot class 4 or 5. Switches are in line type. Primary conductor was 336.

Scope: Install 12 new fifty foot class 3 poles. Install one new triangle air brake switch. Transfer all conductors to new poles

Project Start Date: June 2006

Project Completion Date: December 2006

Project Description: Job #06-081

06-081	1830	$ 819.70	Replacement of old direct buried primary cable and (poletrans) transformer with new primary cable installed in ducts and padmount transformers on Parkside Ave E, Fergus.
	1835	$ 77.06	
	1840	$ 20,678.98	
	1845	$ 23,704.95	
Total Job Cost		**$ 45,280.69**	

Need: Replacement of old direct buried primary cable and transformer.

Scope: Contractor to install 5 concrete transformer bases complete with grounding and re route pre installed empty ducts into bases. Contractor also to install 5 new concrete street light poles, complete with duct. The Applicant's staff to install cable and complete all connections.

Project Start Date: September 2006

Project Completion Date: December 2006

Project Description: Purchase of Replacement International Digger Truck

06-VEH	1930	$ 291,460.16	Purchased new 2007 International 7500 Digger truck

Need: The 2007 Radio Boom Derrick (RBD) was purchased to replace a 1991 RBD (digger truck). Every 12 years, we review and plan for replacement of large equipment. After the decision has been made that we need to replace a large piece of equipment, the actual delivery date can be anywhere from 12-24 months.

Scope: When we are scheduled to replace a large piece of equipment, we normally ask other LDC's we have a relationship with (neighbouring and Co-Op members) to see if they are planning on tendering any new vehicles. If so, in an effort to get better pricing, we will go together on a joint tender and purchase, providing the specifications are similar.

In this particular case, Guelph Hydro was tendering for the exact same type of vehicle we required so we were able to ask the vendors to quote on two (almost identical piece's of work equipment, chassis and boom).

Project Start Date: We started the research for a replacement RBD in 2005. The quotations for the complete unit were submitted around the end of January 2006

Project Completion Date: We took possession of the truck towards the middle of December 2006.

Project Description: 06-CAP

06-CAP	1840	$ 54,303.00	Infrastructure installed by Developers for Ville Lora Downs North Phase 3 and Woodhill Gardens subdivisions.
	1845	$ 92,506.08	
	1850	$ 52,238.10	
	1855	$ 45,071.13	
		$ 244,118.31	

Need: Developer is required to install new infrastructure for Green Field Development, this includes underground conduit, underground conductors and devices, underground transformers and services.

Scope: The developer provides the Applicant with approved drawings. The Applicant then reviews the drawings to ensure that standards and safety issues are addressed.

Project Start Date: November 2005

Project Completion Date: December 2006

Project Description: 2006 Purchase of New Transformers

06-035	1850	$ 84,346.39	Purchase of new underground and overhead transformers during 2006.

Need: Replacement of existing transformers, new transformers and replenish inventory where deemed necessary. Breakdown of purchases are as follows:

- April 2006 ordered – 6-50 kVa IPH PAD ANSI Type 2 UG Transformers - $20,502.72 received Dec 2006

- April 2006 ordered – 1-75 kVa PAD ANSI Type 2 UG Transformer - $4,890.24 received Dec 2006
- April 2006 ordered – 1-100 kVa 1PH PAD ANSI Type 2 UG Transformer $5,407.56 received Dec 2006
- June 2006 ordered – 4-50 kVa 1PH MiniPad UG transformers - $17,215.20 received Nov 2006
- April 2006 ordered – 1-225 kVa 3PH Pole OH transformer - $13,743.00 received Sept 2006
- April 2006 ordered – 1-300 kVa 3PH PAD OH transformer - $12,782.88 received Sept 2006
- April 2006 ordered – 1-75 kVa 3PH PAD OH transformer – $7,418.52 received Sept 2006

Also included in the cost of the transformers is $2,386.27 for labour and miscellaneous small materials used in the installation of the transformers.

Scope: The Superintendent reviews the Applicant's need for new transformers at the time of preparing the annual capital budget and after a physical inventory has been completed of all transformers on hand any units that have reached their useful life are designated for replacement. The Superintendent then obtains prices and orders the required transformers. The lead time on some transformers can be up to forty-eight weeks. Transformer selection is based on transformer loss evaluation formula (Price + (No Load Loss x $8.30) + (Load Loss x $4.10.)

Project Start Date: March 2006

Project Completion Date: December 2006

Project Description: Net increase in contributed capital for 2006

06-CONT	1995	$ (138,546.27)	Contributions and Grants

Need: Developers share of infrastructure for new subdivisions which includes underground conduit, underground conductors and devices, transformers and services of $181,884.11; less

2006 amortization of $43,337.84 for contributions to the end of 2006 with the half year rule applying to acquisitions in 2006.

Scope: The scope in this case was a review of charges submitted by the developer then applying the economic evaluation model to determine the developer's contributions.

Project Start Date: January 2006

Project Completion Date: December 2006

The following projects are not above the materiality level of $25,000.

No.	Project Description	Amount
04-022	Upgraded Conductor on Mill St East in Elora from Geddes St to Kertland St- to improve system reliability	$ 375.11
06-025	Extend secondary conductor to supply newly installed TV amplifier	$ 2,004.49
06-034	Installed new switching cubicle to improve switching options	$ 4,110.98
06-044	120 Union Street - new connection to infill lot	$ 1,282.37
06-049	Intersection of Gartshore and Garafraxa upgraded due to road widening and town installed traffic signals	$ 15,047.45
06-077	125 Union St - new connection	$ 243.02
06-091	Alter overhead line because of road improvements done on Forfar St, Fergus	$ 5,604.02
06-101	Preliminary work	$ 4,214.38
06-102	Install new service at 595 Garafraxa St, Fergus	$ 706.86
06-107	To connect Hydro One customer to our system due to new subdivision construction	$ 259.15
	Invoice #431 and #369	$ (9,218.52)
	Base Connection Refund	$ 1,593.96
	Land rights	$ 1,500.00
	Meters – materials	$ 13,448.46
	Office Furniture and Equipment	$ 7,553.08
	Computer Equipment - Hardware	$ 20,458.77
	Computer Software	$ 6,201.65
	Tools, Shop, Garage Equipment	$ 6,273.18
	Measurement & Testing Equipment	$ 862.92
	Miscellaneous Equipment	$ 6,291.70
	Total Jobs less than 1% variance	$ 88,813.03
	Jobs greater than 1% Variance -(Detailed above)	$ 600,672.76
	Total Jobs 2006	$ 689,485.79

	Total 2006 Actual	$ 689,485.79
	Difference	$ 0.00
	1915 - Office Furntiture - retired and removed furniture from office	$ (4,108.00)
	Total Retirements (From Exhibit 2, Tab 3 and Schedule 3)	$ (4,108.00)
	TOTAL 2006 Asset Additions and Retirements by Project	$ 685,377.79

2007 Year

Total capital additions for the 2007 year were $510,941.43. Those Projects exceeding the materiality threshold of $25,000 are as follows:

Project Description: Job #06-064

06-064	1830	$ 10,530.46	Line upgrade - new pole and conductor in preperation for new large load customer at Heritage River Retirement Home, Elora.
	1835	$ 10,881.28	
	1855	$ 4,283.61	
Total Job Cost		**$ 25,695.35**	

Need: New customer coming on line required a 500 KVA transformer. Existing section of line was substandard, because of pole height and primary conductor size. System neutral was undersized and grounding was not adequate.

Scope: Install five new 45 foot poles. Install new 336 conductor. Installing new 3/0 spun secondary conductor. Install new #2 triplex services. Install new grounding.

Project Start Date: Early May 2007

Project Completion Date: Early June 2007

Project Description: Job #06-081

06-081	1830		Replacement of old direct buried primary cable and (poletrans) transformer with new primary cable installed in ducts and padmount transformers on Parkside Ave E, Fergus.
	1835	$ 496.11	
	1840		
	1845	$ 2,262.23	
Total Job Cost		**$ 2,758.34**	

Need: Replace old direct buried primary cable and poletran type transformers.

Scope: Contractor installed five new concrete transformer bases, complete with grounding. Contractor relocate already installed ducts into new transformer bases and installed fish rope in all ducts to facilitate cable replacement. Contractor also installed 5 new concrete street light poles complete with 2 inch duct. The Applicant installed new primary cables and transformers and completed all connection - primary, secondary and street lights.

In 2007 the Applicant went back to this job and removed the abandoned apparatus and installed a section of new underground to create a loop on the primary feed.

Project Start Date: January 2007

Project Completion Date: January 2007

Project Description: Job #06-101

06-101	1830	$ 42,133.81	Construct new line to conect the F1 feeder and the F2 feeder to improve system reliability
	1835	$ 28,816.15	
	1840	$ 1,275.00	
	1855	$ 317.80	
Total Job Cost		**$ 72,542.76**	

Need: To create loop feed for the F1 and F2 feeders out of station #1. This will eliminate a radial feed on both these feeders, thereby improving reliability of supply to customers, especially the grocery store and plaza at the end of the F1 feeder.

Scope: Construct new pole line as per engineer drawings from Betty Line at St Andrew St W across Grand River to South River Road.

Project Start Date: Late July 2007

Project Completion Date: November 2007

Project Description: Job #07-060

07-060	1830	$ 408.50	Replace old direct buried with new primary cable installed in ducts and replace two poletran type transformers with one new padmount transformer on Albert St E, Fergus.
	1835	$ 460.65	
	1840	$ 17,480.00	
	1845	$ 7,496.77	
	1850	$ 1,154.77	
	1855	$ 951.33	
Total Job Cost		**$ 27,952.02**	

Need: Replace old direct buried primary cable and two poletrans type transformers with new primary cables in duct and one new padmount transformer.

Scope: Contractor installed all duct, transformer base and grounding and two concrete street light poles. The Applicant installed cables and completed all connections, including primary, secondary and street lights.

Project Start Date: Late October 2007

Project Completion Date: Late November 2007

Project Description: Conversion to NorthStar – Harris Computers

07-XXX	1925	$ 52,270.32	Conversion from Harris PUBS to Harris Northstar version 6

Need: The CIS provider had made major changes to the billing system to enhance performance and flexibility within the system. NorthStar V6 is windows friendly and allows access to additional reports.

Scope: Included review of changes to upgraded NorthStar V6 billing system, determination of operating platform, arranging with IT hosting company to have hardware in place, assuring conductivity, then arranging for conversion training, testing and cutover.

Project Start Date: May 7, 2007

Project Completion Date: June 29, 2007

Project Description: Replacement of existing Dump Truck

07-VEH	1930	$ 60,579.55	Purchased 2007 Dodge Ram 3500 4x4 Dump Truck

Need: It was determined that by purchasing a new dump truck we could divest of the old dump truck as well as a pickup truck.

Scope: Quotations were received in March 2007 for a new dump truck. The Dodge Ram 3500 came in with the best price and options and a purchase order was issued.

Project Start Date: March 2007

Project Completion Date: July 2007 – Just prior to delivery the Applicant sold the 1995 dump truck as well as a 1998 pickup truck.

Project Description: 2007 Purchase of New Transformers

07-TRANS	1850	$ 86,212.69	Purchase of new underground and overhead transformers during 2007.

Need: Replacement of existing transformers, new transformers and replenish inventory will deemed necessary. Breakdown of purchases are as follows:

- Oct 2006 ordered – 1-112 kVa 3PH POLE OH Transformers - $7,076.16 received Jan 2007
- July 2007ordered – 1-300 kVa 3PH PAD Mount OH Transformer - $18,554.40 received Sept 2007
- Nov 2006 ordered – 1-500 kVa 3PH PAD OH Transformer $21,892.68 received Sept 2007
- Feb 2007 ordered – 1-150 kVa 3PH PAD OH transformers - $12,150.00 received Oct 2007
- Sept 2007 ordered – 1-50 kVa 1PH PAD OH transformer - $4,627.80 received Dec 2007
- Sept 2007 ordered – 2-50 kVa 1PH PAD OH transformer - $9,255.60 received Dec 20076
- Feb 2007 ordered – 1-150 kVa 3PH PAD UG transformer – $12,150.00 received Dec 2007

Also included in the cost of the transformers is $506.05 for labour and miscellaneous small materials used in the installation of the transformers.

Scope: The Superintendent reviews the utilities need for new transformers at the time of preparing the annual capital budget and after a physical inventory has been completed of all transformers on hand any units that have reached their useful life are designated for replacement. The Superintendent then obtains prices and places orders for the required transformers. The lead time on some transformers can be up to forty-eight weeks.

Project Start Date: October 2006

Project Completion Date: December 2007

Project Description: Net decrease in contributed capital for 2007

07-XXX	1995	$ 46,975.44	Contributed Capital depreciation for 2007

Need: The amount of $46,975.44 represents the amount of amortization on contributed capital accounts for 2007. There was no new contributed capital for the 2007 year.

Scope: Recording 2007 amortization of contributed capital. Amortization is recorded as a debit against the contributed capital amount.

Project Start Date: January 2007

Project Completion Date: December 2007

The following projects, on next page, are not above the materiality level of $25,000.

No.	Project Description	Amount
06-053		$ 1,087.50
07-013	New poles – John St and Colborne St, Elora, needed additional clearance	$ 3,674.53
07-018	Belsyde reconstruction – new poles and switch due to age	$ 21,775.32
07-020	Upgrade pole 5' higher Bell cable too close to traffic light for additional clearance – Gartshore St, Fergus	$ 1,656.95
07-026		$ 320.16
07-038	New service for Bell – Bridge St, Elora	$ 3,797.17
07-048	Underground service – 81 McNab St, Elora	$ 1,206.24
07-054		$ 128.07
07-055	replace two steel poles with wood on Colquhoun St, Fergus to improve safety	$ 3,662.57
07-056	Herrick St, Fergus replace rotten pole	$ 10,998.56
07-059		$ 1,721.88
07-067	Storm Damage 165 Garafraxa St, Fergus Pole Replacement	$ 1,849.90
07-081	Gartshore St – New pole - due to road widening	$ 2,176.30
07-083	Church Street - pole repositioning due to age of pole. Pole was in the back yard, and was moved to street	$ 2,328.77
07-091	Overhead line improvements	$ 8,670.30
	New connections 2007 - no job number	$ 12,395.27
	New Meters for 2007	$ 6,669.71
	Land Rights	$ 3,381.19
	Office Furniture and Equipment	$ 18,265.95
	New CPU tower enclosure	$ 1,154.22
	New server and isntallation (DC01Server)	$ 12,723.15
	New Server and isntallation (DC02Server)	$ 5,581.36
	New computer and monitor for SCADA System	$ 3,707.64
	New laptop (1) for Linesmen	$ 2,573.21
	Tools, Shop and Garage Equipment - purchased Impact Torq Hydraulic drill and generators	$ 3,952.30
	Communication Equipment - Polycom conference phone	$ 496.78
	Total Jobs less than 1% variance	$ 135,955.00
	Jobs greater than 1% Variance	$ 374,986.47
	Total Jobs 2007	$ 510,941.43
	Total 2007 (From Exhibit 2, Tab 3, Schedule 2 - Capital Additions)	$ 510,941.43
	Difference	$ -
	Sale of 1994 Bucket Truck to Job Inc.	$ (190,289.00)
	Total Retirements (From Exhibit 2, Tab 3 and Schedule 3)	$ (190,289.00)
	TOTAL 2007 Asset Additions and Retirements by Project	$ 320,652.43

2008 Year

Total capital additions for the 2008 year are projected to be $512,600. Those Projects exceeding the materiality threshold of $25,000 are as follows:

Project Description: Job #08-002

08-002	1830	$ 12,700.00	Install 3 phase connection for commercial property on Mill St Elora
	1835	$ 11,700.00	
	1850	$ 36,000.00	
Total Job Cost		**$ 60,400.00**	

Need: New commercial building to be constructed which will require a three phase primary connection to a 150 KVA padmount transformer.

Scope: Extend three phase circuit on Hydro One poles and one span across Mill St. to new riser pole.

Project Start Date: August 2008

Project Completion Date: September 2008

Project Description: Job #08-003

08-003	1830	$ 18,200.00	New pole line on new road into industrial lands north of Glengarry to service new industrial park. Seven 50 foot poles and 336 conductor.
	1835	$ 18,200.00	
Total Job Cost		**$ 36,400.00**	

Need: New three phase pole line required to service newly created industrial lots.

Scope: Install seven fifty foot poles complete with 336 conductor on phases and neutral.

Project Start Date: June 2008

Project Completion Date: June 2008

Project Description: Job #08-004

08-004	1830	$ 28,600.00	Highway 6 and McQueen Blvd - new concrete poles for 4 kv and 44 kv as well as new UG primary under McQueen to loop feed padswitch
	1835	$ 28,800.00	
	1840	$ 6,700.00	
	1845	$ 16,500.00	
Total Job Cost		**$ 80,600.00**	

Need: Existing pole line will need to be relocated because of planned road and intersection improvements by the municipality, MTO and the county.

Scope: Relocate poles and conductor as required. Existing underground primary cable routes have to be abandoned and new routes installed during road construction.

Project Start Date: August 2008

Project Completion Date: October 2008

Project Description: Job #08-005

08-005	1830	$11,200.00	Reframe poles as required in order to upgrade conductor, reduce line losses and improve system reliability
	1835	$ 23,600.00	
Total Job Cost		**$ 34,800.00**	

Need: Upgrade conductor to improve system reliability and reduce line losses.

Scope: Install 336 conductor from Breadalbane St to Beatty Line along Patrick Lane.

Project Start Date: March 2008

Project Completion Date: June 2008

Project Description: Job #08-XXX

08-XXX	1850	**$ 111,000.00**	New padmount transformers of various sizes

Need: New padmount transformers required to have in stock for projects that will come during the year and for replacements. The lead time for transformers in 2006 and 2007 was up to 48 weeks for 3 phase padmounts.

- Ordered – 2 - 500 KVA padmounts underground transformer approx. $49,000
- Ordered – 6 – 50 KVA padmounts underground transformers approx. $30,000
- Ordered - 1 – 112 KVA 347/600 padmount Underground transformer approx. $16,000
- Ordered - 1 – 150 KVA 347/600 padmount underground transformer approx $16,000

Scope: The Superintendent reviews the utilities need for new transformers at the time of preparing the annual capital budget and after a physical inventory has been completed of all transformers on hand any units that have reached their useful life are designated for replacement. The Superintendent then obtains prices and places orders for the required transformers. The lead time on some transformers can be up to forty-eight weeks.

Project Start Date: All ordered in the last year, 2007.
Project Completion Date: Delivered to the Applicant in 2008.

Project Description: Upgrade of Financial System

08-COMP1	1925	$ 36,000.00	Phase one upgrade to Cayenta Financials from Harris Computers

Need: To upgrade the Financial System to a more robust system. Requirements being imposed on the utility to track assets, better tracking of cost and cost estimates, and better reporting tools are forcing an upgrade.

Scope: The Applicant has reviewed the Financial System and has talked to current users. Selection process was made and due to the complexity and work involved the Applicant has decided to phase the implementation between September 2008 and May 2010. This will allow for testing and the ability to meet other deadlines. Phase 2: Is the implementation and going live with the Financial portion of the program. This phase will cover cost of training and implementation of the program, License fees and expenses. The Financial portion includes:

General Ledger, Accounts Payable, Purchasing Inventory and Payroll. Phase 3 is the implementation of fixed assets, work order and Job cost modules in 2010 at an estimated cost of $74,000.

Project Start Date: September 2008

Project Completion Date: May 2010

Project Description: Purchase digital filing and search system

08-COMP2	1925	$ 45,000.00	Purchase Digital filing and search system

Need: The ability to file reports electronically and search documents in a timelier manner. This system allows reports to be put in secured files with limited access, eliminates paper copies and reduces the need for storage space. It also allows expansion of records management to filing engineering documents, account payable, etc. electronically.

Scope: Review of systems, selection process and license jointly to reduce costs.

Project Start Date: August 2008

Project Completion Date: October 2008

Project Description: Purchase Cognos Reporting Tool and Training

08-COMP3	1925	$ 15,000.00	Purchase of Cognos Reporting Tool and Training

Need: The Cognos reporting tool will allow in house linking of fields/tables within the CIS system in order to produce required reports. Cognos will allow existing staff to create their own reports in most cases without having to contract services with outside IT vendor. Cognos also enhances reports and allows them to be tailored to the Applicants needs.

Scope: Review system, talk to other users, vendors. Determine hardware requirements and arrange for training.

Project Start Date: October 2008

Project End Date: November 2008

The following projects, on next page are not above the materiality level of $25,000.

No.	Project Description	Amount
08-XXX	Easements at Price Chopper's	$ 4,000
08-XXX	Services - all new connections	$ 22,900
	Meters	$ 15,000
08-XXX	Install new tile at office (1915)	$ 20,000
08-XXX	Replacement of existing computers, color printer	$ 13,000
08-XXX	New stores equipment	$ 1,000
08-XXX	Purchase new power washer with direct outside ventelation and other tools and shop equipment	$ 14,000
08-XXX	Purchase new meter testing equipment	$ 1,000
08-XXX	Purchase miscellaneous equipment	$ 2,500
	Total Jobs less than 1% variance	$ 93,400
	Jobs greater than 1% Variance	$ 359,200
	Total Jobs 2008	$ 452,600
	Total 2008 Budget	$ 512,600
	Difference	$ 60,000
	1915 - Office Furntiture - retired and removed furniture from office	$ (20,559)
	1920 - Wrote off and disposed comptuers	$ (55,284)
	1940 - Wrote off and disposed of tools, shop and garage equipment	$ (17,955)
	1950 - Wrote off and disposed of power operated equipment	$ (10,720)
	Total Asset Retirements (From Exhibit 2, Tab 3, Schedule 3)	$ (104,518)
	TOTAL 2008 Asset Additions and Retirements by Project	$ 408,082

2009 Year

Total capital additions for the 2009 year are projected to be $815,600. Those Projects exceeding the materiality threshold are as follows:

Project Description: Job #09-001

09-001	1830	$ 43,600.00	Job 09-001 - Reconstruct Belsyde Ave from St David St to Scotland St. Install new 50' poles, updgrade conductor as required, install new polemount transformers and upgrade secondary conductor
	1835	$ 60,000.00	
	1850	$ 31,100.00	
	1855	$ 23,800.00	
Total Job Cost		**$ 158,500.00**	

Need: The conductor along this section of line has a lot of sleeves in it and the poles are substandard for clearances. The 44 kV line should be extended from St Andrew St West along Scotland St to Belsyde Ave to connect with the 44kV coming in along County Road 18. This would enhance the reliability to our system by providing us with the ability to feed our system from two directions.

Scope: Install twelve 50 foot poles along Scotland Street from St Andrew St West to Belsyde Ave. Install new 336 conductor on top for 44 KV circuit and for 4KV underbuild. Install new 3/0 span secondary. Install all new #2 Triplex services. Install replacement transformers.

Project Start Date: April 2009

Project Completion Date: July 2009

Project Description: Job #09-002

09-002	1830	$ 66,900.00	Job 09-002 - Reconstruct Scotland St under 44 kv, upgrade 4 kv conductor, install new secition of 44 kv to create a tie, install new polemount transformers, poles and secondary conductor
	1835	$ 76,300.00	
	1850	$ 16,100.00	
	1855	$ 24,400.00	
Total Job Cost		**$ 183,700.00**	

Need: All poles on this section are old and short with open buss secondary.

Scope: Install fourteen 50 foot poles along Belsyde Ave from Scotland St to St David St South, Hydro One circuit will remain on top of the poles. Install new 336 conductor on 4kv circuit. Install 3/0 spun secondary conductor. Install new 2 triplex services. Install replacement transformers. Upgrade all risers with new switches and arrestors.

Project Start Date: September 2009

Project Completion Date: November 2009

Project Description: Job #09-003

09-003	1845	$ 19,200.00	Eastwood Subdivision for 2009
	1850	$ 75,000.00	
	1855	$ 11,500.00	
Total Job Cost		**$ 105,700.00**	

Need: Pole changes will be required in order to connect to the overhead line to allow for connection to the 4kv circuit. Developer intends to begin this subdivision in late 2008; the Applicant will not be required to start work until 2009 with an expected in-service date later in the year.

Scope: Install two 65 foot poles, transfer two 44 KV circuits, one 8 KV circuit and one 4 KV circuit. Build two new risers to service subdivision. Inspect underground system as it is being installed by developer's contractors. Complete all connections on primary, secondary and street lights.

Project Start Date: March 2009

Project Completion Date: Early April 2009

Project Description: Job #09-004

09-004	1850	**$ 183,700.00**	New Transformers 2009

Need: New padmount transformers required for expected projects during the year and for scheduled and emergency replacements. The lead time for transformers in 2006 and 2007 was up to 48 weeks for 3 phase padmounts.

Scope: The Superintendent reviews the utilities need for new transformers at the time of preparing the annual capital budget and after a physical inventory has been completed of all transformers on hand any units that have reached their useful life are designated for replacement. The Superintendent then obtains prices and orders the required transformers.

- 4 – 75 KVA Padmount Underground Transformers – Approx. $45,000

- 2 – 112.5 KVA Padmount Underground Transformers – Approx. $ 26,100
- 2 – 150 KVA Padmount Underground Transformers – Approx. $ 24,500
- 2 – 300 KVA Padmount Underground Transformers– Approx. $ 37,000
- 15 – 50 KVA Padmount Underground Transformers - Approx. $40,000

Project Start Date: Ordered in 2008

Project Completion Date: Will be delivered to the Applicant 2009

Project Description: Job #09-005

09-005	1930	$ 45,000.00	New F150 Pickup Truck

Need: To replace existing 2001 F250 Heavy Duty, with a regular pickup truck. The F250 is the oldest truck in smaller trucks category.

Scope: The Applicant is able to go to a smaller truck, because of the versatility of the dump truck.

Project Start Date: Early 2009

Project Completion Date: Early 2009

Project Description: Job #09-006

09-006	1925	$ 82,000.00	Upgrade to Cayenta Financials from Harris Computers

Need: To upgrade the Financial System to a more robust system. Requirements being imposed on the utility to track assets, better tracking of cost and cost estimates, and better reporting tools are forcing an upgrade. Phase 2: Is the implementation and going live with the Financial portion of the program. This phase will cover cost of training and implementation of the program, License fees and expenses Financial portion includes: General Ledger, Accounts Payable, Purchasing Inventory and Payroll. Phase 3 is the implementation of fixed assets, work order and Job cost modules in 2010 at an estimated cost of $74,000.

Scope: Work with CIS vendor, IT hosting vendor and staff to ensure smooth implementation.

Project Start Date: September 2008

Project Completion Date: May 2010

Project Description: Job #09-007

09-007	1920	$ 29,000.00	Purchase new computer equipment

Need: Includes the replacement of 3 in-house servers and one desktop computer, which will be in its 4th year of service. Also included is the replacement cost of a major printer which will be 10 years old.

Scope: Review system requirements and ensure that servers currently quoted will meet the needs, place order and arrange for conversion of existing data.

Project Start Date: January 2009

Project Completion Date: December 2009

The following projects are not above the materiality level of $25,000.

No.	Project Description	Amount
	Easements related to Belsyde or Scotland or Eastwood Subdivision	$ 4,000.00
	Underground conduit - could be various jobs	$ 5,000.00
	Meters	$ 15,000.00
	Stores Equipment	$ 1,000.00
	Tools, Shop and Garage Equipment	$ 2,000.00
	Measurement & Testing Equip	$ 1,000.00
	Total Jobs less than 1% variance	$ 28,000.00
	Jobs greater than 1% Variance	$ 787,600.00
	Total Jobs 2009	$ 815,600.00
	Total 2009 Budget	$ 815,600.00
	Difference	$ -

Summary of Asset Additions

Gross Capital Asset Account	2006 Additions	2007 Additions	2008 Projected Additions	2009 Projected Additions
1610-Miscellaneous Intangible Plant	$ -	$ -	$ -	$ -
1805-Land	$ -	$ -	$ -	$ -
1806-Land Rights	$ 1,500	$ 3,381	$ 4,000	$ 4,000
1820-Distribution Station Equipment - Normally Primary below 50 kV	$ -	$ -	$ -	$ -
1825-Storage Battery Equipment	$ -	$ -	$ -	$ -
1830-Poles, Towers and Fixtures	$ 49,377	$ 84,927	$ 70,700	$ 110,500
1835-Overhead Conductors and Devices	$ 32,736	$ 64,645	$ 82,300	$ 136,300
1840-Underground Conduit	$ 79,093	$ 18,755	$ 6,700	$ 5,000
1845-Underground Conductors and Devices	$ 116,336	$ 9,759	$ 16,500	$ 19,200
1850-Line Transformers	$ 129,280	$ 87,367	$ 147,000	$ 306,000
1855-Services	$ 67,161	$ 27,157	$ 22,900	$ 59,600
1860-Meters	$ 13,448	$ 6,670	$ 15,000	$ 15,000
1915-Office Furniture and Equipment	$ 7,553	$ 18,266	$ 20,000	$ -
1920-Computer Equipment - Hardware	$ 20,459	$ 25,740	$ 13,000	$ 29,000
1925-Computer Software	$ 6,202	$ 52,270	$ 96,000	$ 82,000
1930-Transportation Equipment	$ 291,460	$ 60,580	$ -	$ 45,000
1935-Stores Equipment	$ -	$ -	$ 1,000	$ 1,000
1940-Tools, Shop and Garage Equipment	$ 6,273	$ 3,952	$ 14,000	$ 2,000
1945-Measurement and Testing Equipment	$ 863	$ -	$ 1,000	$ 1,000
1950-Power Operated Equipment	$ -	$ -	$ -	$ -
1955-Communication Equipment	$ -	$ 497	$ -	$ -
1960-Miscellaneous Equipment	$ 6,292	$ -	$ 2,500	$ -
1995-Contributions and Grants - Credit	$ (138,546)	$ 46,975	$ -	$ -
TOTAL	**$ 689,486**	**$ 510,941**	**$ 512,600**	**$ 815,600**

The increase in overhead plant expenditures in 2008 and 2009 continues to be offset by decreased spending on underground plant.

In 2008 and 2009 a steady increase can be seen in account 1950 – Line Transformers. Until about 2004/2005 the Applicant bought surplus transformers from neighbouring utilities at a very reasonable cost.

With the introduction of Ontario Regulation 22/04 (Ont. Reg 22/04) this practice became cost prohibitive because of the requirement to have test reports for each transformer, new or used.

Since that time the Applicant purchased new transformers and only those that were not in inventory. The result of this is that our stock of padmount transformers was depleted and we are now building up an inventory of new transformers.

The cost of new transformers has increased significantly over the past four years.

Summary of Asset Retirements

Gross Capital Asset Account	2006 Retirements	2007 Retirements	2008 Projected Retirements	2009 Projected Retirements
1915-Office Furniture and Equipment	$ 4,108	$ -	$ 20,559	$ -
1920-Computer Equipment - Hardware		$ -	$ 55,284	$ -
1930-Transportation Equipment		$ 190,289	$ -	$ -
1940-Tools, Shop and Garage Equipment		$ -	$ 17,955	$ -
1950-Power Operated Equipment		$ -	$ 10,720	$ -
TOTAL	**$ 4,108**	**$ 190,289**	**$ 104,518**	**$ -**

Leave to Construction (under Section 92)

Not Applicable

Fixed Assets and Associate Depreciation Rates

Fixed Assets and Associated Depreciation Rates

USAacct	AcctDesc	Useful Life	Depr %
1805	1805-Land	0	0
1806	1806-Land Rights	0	0
1808	1808-Buildings and Fixtures	50	2
1810	1810-Leasehold Improvements	25	4
1815	1815-Transformer Station Equipment - Normally Primary above 50 kV	-	-
1820	1820-Distribution Station Equipment - Normally Primary below 50 kV	30	3.3
1830	1830-Poles, Towers and Fixtures	25	4
1835	1835-Overhead Conductors and Devices	25	4
1840	1840-Underground Conduit	25	4
1845	1845-Underground Conductors and Devices	25	4
1850	1850-Line Transformers	25	4
1855	1855-Services	25	4
1860	1860-Meters	25	4
1905	1905-Land	0	0
1906	1906-Land Rights	0	0
1908	1908-Buildings and Fixtures	25	4
1910	1910-Leasehold Improvements	-	-
1915	1915-Office Furniture and Equipment	10	10
1920	1920-Computer Equipment - Hardware	5	20
1925	1925-Computer Software	3	33.3
1930	1930-Transportation Equipment – small trucks/vehicles	4	25
1930	1930-Transportation Equipment – Trucks <3 Tons	5	20
1930	1930-Transportation Equipment – Trucks>3 Tons	8	12.5
1935	1935-Stores Equipment	10	10
1940	1940-Tools, Shop and Garage Equipment	10	10
1945	1945-Measurement and Testing Equipment	10	10
1950	1950-Power Operated Equipment	-	-
1955	1955-Communication Equipment	-	-
1960	1960-Miscellaneous Equipment	-	-
1965	1965-Water Heater Rental Units	-	-

1970	1970-Load Management Controls - Customer Premises	-	-
1975	1975-Load Management Controls - Utility Premises	-	-
1980	1980-System Supervisory Equipment	15	6.7
1985	1985-Sentinel Lighting Rental Units	-	-
1995	1995-Contributions and Grants - Credit	25	4

System Expansions

Subdivision Development or other Expansions to the Distribution System:

The primary driver for this category is residential development. Work involves installing residential overhead and underground distribution systems and components and/or inspecting such work performed by a developer's contractor. The economic evaluation and capital contribution processes required by the Distribution System Code are applied to residential expansions when required. The Applicant’s service territory is currently at the Municipal boundary leaving little room for substantial growth into the future.

Capitalization Policy

The Applicant applies the following general capitalization policies and principles based on Generally Accepted Accounting Principles ("GAAP"), in particular CICA Handbook Section 3060 Capital Assets, as well as guidelines set out by the Ontario Energy Board, where applicable:

- The amount to be capitalized is the cost to acquire or construct a capital asset, including any ancillary costs incurred to place a capital asset into its intended state of operation. The Applicant does not currently capitalize interest on funds used during construction.

- Assets that are intended to be used on an on-going basis and are expected to provide future economic benefit (generally considered to be greater than one year) will be capitalized.

- General Plant items with an estimated useful life greater than one year and valued at greater than $500 will be capitalized.

- Expenditures that create a physical betterment or improvement of the asset (i.e. there is a significant increase in the physical output or service capacity; or the useful life of the capital asset is extended) will be capitalized.

With respect to transportation equipment (e.g. vehicles), all costs associated with putting a vehicle into service are capitalized.

Allowance for Working Capital

Summary of 2008 Working Capital Allowance

Expenses for Working Capital	2009 Projection	2008 Projection	Var $ (2009 Vs 2008)	2007 Actual	Var $ (2008 vs 2007)	2006 Actual	Var $ (2007 vs 2006 Act)	2006 EDR Approved	Var $ (2006 Act vs 2006 EDR)
Eligible Distribution Expenses:	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3500-Distribution Expenses - Operation	$ 264,900	$ 284,900	$ (20,000)	$ 256,507	$ 28,393	$ 218,322	$ 38,185	$ 175,881	$ 42,442
3550-Distribution Expenses - Maintenance	$ 292,600	$ 296,200	$ (3,600)	$ 252,713	$ 43,487	$ 247,085	$ 5,629	$ 258,340	$ (11,255)
3650-Billing and Collecting	$ 332,200	$ 323,100	$ 9,100	$ 314,401	$ 8,699	$ 328,595	$ (14,194)	$ 285,425	$ 43,170
3700-Community Relations	$ 35,600	$ 56,500	$ (20,900)	$ 42,778	$ 13,722	$ 51,191	$ (8,413)	$ 21,753	$ 29,438
3800-Administrative and General Expenses	$ 786,300	$ 739,200	$ 47,100	$ 636,151	$ 103,049	$ 588,417	$ 47,733	$ 706,526	$ (118,108)
3950-Taxes Other Than Income Taxes	$ 35,000	$ 33,000	$ 2,000	$ 31,436	$ 1,564	$ 52,866	$ (21,430)	$ 30,832	$ 22,034
Total Eligible Distribution Expenses	**$ 1,746,600**	**$ 1,732,900**	**$ 13,700**	**$ 1,533,986**	**$ 198,914**	**$ 1,486,476**	**$ 47,510**	**$ 1,478,756**	**$ 7,720**
3350-Power Supply Expenses	$ 11,369,553	$ 11,335,522	$ 34,032	$ 10,282,924	$ 1,052,598	$ 8,974,004	$ 1,308,920	$ 10,541,659	$ (1,567,655)
Total Expenses for Working Capital	**$ 13,116,153**	**$ 13,068,422**	**$ 47,732**	**$ 11,816,910**	**$ 1,251,511**	**$ 10,460,480**	**$ 1,356,430**	**$ 12,020,415**	**$ (1,559,935)**
Working Capital factor	15%	15%		15%		15%		15%	
Working Capital Allowance	**$ 1,967,423**	**$ 1,960,263**	**$ 7,160**	**$ 1,772,537**	**$ 187,727**	**$ 1,569,072**	**$ 203,465**	**$ 1,803,062**	**$ (233,990)**

Working Capital Allowance calculations by accounts

Eligible Distribution Expenses:	2009 @ existing rates	Allowance for Working Capital 15%	2008 Projection	Allowance for Working Capital 15%	2007 Actual	Allowance for Working Capital 15%	2006 Actual	Allowance for Working Capital 15%
3500-Distribution Expenses - Operation								
5005-Operation Supervision and Engineering	$ 94,500	$ 14,175	$ 92,000	$ 13,800	$ 97,211	$ 14,582	$ 70,850	$ 10,628
5010-Load Dispatching	$ 18,200	$ 2,730	$ 17,400	$ 2,610	$ 16,600	$ 2,490	$ 12,887	$ 1,933
5012-Station Buildings and Fixtures Expense	$ 29,400	$ 4,410	$ 27,000	$ 4,050	$ 33,594	$ 5,039	$ 29,445	$ 4,417
5017-Distribution Station Equipment - Operation Supplies and Expenses	$ -	$ -	$ -	$ -	$ 7	$ 1	$ -	$ -
5020-Overhead Distribution Lines and Feeders - Operation Labour	$ 1,200	$ 180	$ 950	$ 143	$ 416	$ 62	$ 396	$ 59
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$ -	$ -	$ 900	$ 135	$ -	$ -	$ 624	$ 94
5030-Overhead Subtransmission Feeders - Operation	$ 1,000	$ 150	$ 950	$ 143	$ 208	$ 31	$ 1,006	$ 151
5035-Overhead Distribution Transformers-Operation	$ 1,600	$ 240	$ 300	$ 45	$ 671	$ 101	$ 191	$ 29
5040-Underground Distribution Lines and Feeders - Operation Labour	$ 3,100	$ 465	$ 700	$ 105	$ 627	$ 94	$ 1,782	$ 267
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$ 1,000	$ 150	$ 1,000	$ 150	$ 797	$ 119	$ 406	$ 61
5055-Underground Distribution Transformers - Operation	$ 1,000	$ 150	$ 7,200	$ 1,080	$ 577	$ 87	$ 699	$ 105
5065-Meter Expense	$ 62,500	$ 9,375	$ 87,400	$ 13,110	$ 70,404	$ 10,561	$ 54,097	$ 8,115
5070-Customer Premises - Operation Labour	$ 1,200	$ 180	$ 1,100	$ 165	$ 1,166	$ 175	$ 1,122	$ 168
5085-Miscellaneous Distribution Expense	$ 45,700	$ 6,855	$ 43,500	$ 6,525	$ 29,869	$ 4,480	$ 36,098	$ 5,415
5095-Overhead Distribution Lines and Feeders - Rental Paid	$ 4,500	$ 675	$ 4,500	$ 675	$ 4,359	$ 654	$ -	$ -

5096-Other Rent	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,719	$ 1,308
3550-Distribution Expenses - Maintenance								
5105-Maintenance Supervision and Engineering	$ 52,600	$ 7,890	$ 50,500	$ 7,575	$ 42,047	$ 6,307	$ 42,061	$ 6,309
5110-Maintenance of Buildings and Fixtures - Distribution Stations	$ 4,400	$ 660	$ 3,300	$ 495	$ 1,153	$ 173	$ 1,415	$ 212
5114-Maintenance of Distribution Station Equipment	$ 44,800	$ 6,720	$ 36,400	$ 5,460	$ 52,555	$ 7,883	$ (811)	$ (122)
5120-Maintenance of Poles, Towers and Fixtures	$ 26,100	$ 3,915	$ 30,000	$ 4,500	$ 7,872	$ 1,181	$ 18,096	$ 2,714
5125-Maintenance of Overhead Conductors and Devices	$ 47,800	$ 7,170	$ 51,800	$ 7,770	$ 28,987	$ 4,348	$ 41,025	$ 6,154
5130-Maintenance of Overhead Services	$ 13,700	$ 2,055	$ 14,600	$ 2,190	$ 13,809	$ 2,071	$ 30,817	$ 4,623
5135-Overhead Distribution Lines and Feeders - Right of Way	$ 33,100	$ 4,965	$ 41,400	$ 6,210	$ 42,894	$ 6,434	$ 48,788	$ 7,318
5145-Maintenance of Underground Conduit	$ 5,700	$ 855	$ 5,300	$ 795	$ 959	$ 144	$ 3,046	$ 457
5150-Maintenance of Underground Conductors and Devices	$ 5,800	$ 870	$ 3,900	$ 585	$ 2,308	$ 346	$ 4,331	$ 650
5155-Maintenance of Underground Services	$ 27,000	$ 4,050	$ 30,400	$ 4,560	$ 32,029	$ 4,804	$ 27,916	$ 4,187
5160-Maintenance of Line Transformers	$ 30,000	$ 4,500	$ 27,100	$ 4,065	$ 26,336	$ 3,950	$ 30,253	$ 4,538
5175-Maintenance of Meters	$ 1,600	$ 240	$ 1,500	$ 225	$ 1,764	$ 265	$ 148	$ 22
3650-Billing and Collecting								
5310-Meter Reading Expense	$ 36,100	$ 5,415	$ 36,000	$ 5,400	$ 39,452	$ 5,918	$ 39,917	$ 5,988
5315-Customer Billing	$ 231,000	$ 34,650	$ 209,800	$ 31,470	$ 213,142	$ 31,971	$ 219,626	$ 32,944
5320-Collecting	$ 61,500	$ 9,225	$ 73,700	$ 11,055	$ 57,264	$ 8,590	$ 68,951	$ 10,343
5325-Collecting- Cash Over and Short	$ 100	$ 15	$ 100	$ 15	$ (2)	$ (0)	$ 21	$ 3
5330-Collection Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5335-Bad Debt Expense	$ 3,500	$ 525	$ 3,500	$ 525	$ 4,546	$ 682	$ 81	$ 12
5340-Miscellaneous Customer Accounts Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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Eligible Distribution Expenses:	2009 @ existing rates	Allowance for Working Capital 15%	2008 Projection	Allowance for Working Capital 15%	2007 Actual	Allowance for Working Capital 15%	2006 Actual	Allowance for Working Capital 15%
3700-Community Relations								
5405-Supervision	$ 2,400	$ 360	$ 2,000	$ 300	$ 1,873	$ 281	$ 1,583	$ 237
5410-Community Relations - Sundry	$ 3,800	$ 570	$ 42,300	$ 6,345	$ 8,061	$ 1,209	$ 16,687	$ 2,503
5415-Energy Conservation	$ 9,600	$ 1,440	$ 4,300	$ 645	$ 28,645	$ 4,297	$ 23,203	$ 3,480
5420-Community Safety Program	$ 3,500	$ 525	$ -	$ -	$ -	$ -	$ -	$ -
5425-Miscellaneous Customer Service and Informational Expenses	$ 16,300	$ 2,445	$ 7,900	$ 1,185	$ 4,199	$ 630	$ 9,718	$ 1,458
3800-Administrative and General Expenses								
5610-Management Salaries and Expenses	$ 263,800	$ 39,570	$ 257,000	$ 38,550	$ 243,537	$ 36,531	$ 222,403	$ 33,360
5615-General Administrative Salaries and Expenses	$ 191,400	$ 28,710	$ 188,000	$ 28,200	$ 141,524	$ 21,229	$ 129,478	$ 19,422
5620-Office Supplies and Expenses	$ 49,200	$ 7,380	$ 42,700	$ 6,405	$ 41,546	$ 6,232	$ 42,876	$ 6,431
5630-Outside Services Employed	$ 50,000	$ 7,500	$ 65,600	$ 9,840	$ 34,578	$ 5,187	$ 52,315	$ 7,847
5635-Property Insurance	$ 12,000	$ 1,800	$ 11,000	$ 1,650	$ 11,022	$ 1,653	$ 10,757	$ 1,614
5640-Injuries and Damages	$ 33,200	$ 4,980	$ 29,000	$ 4,350	$ 31,761	$ 4,764	$ 14,502	$ 2,175
5645-Employee Pensions and Benefits	$ 6,700	$ 1,005	$ 10,000	$ 1,500	$ 8,394	$ 1,259	$ (482)	$ (72)
5655-Regulatory Expenses	$ 65,200	$ 9,780	$ 25,800	$ 3,870	$ 27,016	$ 4,052	$ 24,266	$ 3,640
5660-General Advertising Expenses	$ 1,500	$ 225	$ 1,300	$ 195	$ 1,229	$ 184	$ 2,391	$ 359
5665-Miscellaneous General Expenses	$ 85,300	$ 12,795	$ 81,500	$ 12,225	$ 73,041	$ 10,956	$ 69,717	$ 10,458
5675-Maintenance of General Plant	$ 19,000	$ 2,850	$ 19,500	$ 2,925	$ 16,341	$ 2,451	$ 12,567	$ 1,885
5680-Electrical Safety Authority Fees	$ 9,000	$ 1,350	$ 7,800	$ 1,170	$ 6,161	$ 924	$ 7,626	$ 1,144
3950-Taxes Other Than Income Taxes		$ -		$ -		$ -		$ -
6105-Taxes Other Than Income Taxes	$ 35,000	$ 5,250	$ 33,000	$ 4,950	$ 31,436	$ 4,715	$ 52,866	$ 7,930
Total Eligible Distribution Expenses	**$ 1,746,600**		**$ 1,732,900**		**$ 1,533,986**		**$ 1,486,476**	
3350-Power Supply Expenses		$ -		$ -		$ -		$ -
4705-Power Purchased	$ 8,779,551	$ 1,316,933	$ 8,764,519	$ 1,314,678	$ 8,023,977	$ 1,203,597	$ 6,749,018	$ 1,012,353
4708-Charges-WMS	$ 837,682	$ 125,652	$ 836,248	$ 125,437	$ 619,400	$ 92,910	$ 779,417	$ 116,913
4710-Cost of Power Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4714-Charges-NW	$ 819,716	$ 122,957	$ 577,619	$ 86,643	$ 725,106	$ 108,766	$ 726,814	$ 109,022

4716-Charges-CN	$ 680,511	$ 102,077	$ 907,319	$ 136,098	$ 670,991	$ 100,649	$ 666,001	$ 99,900
4720-Other Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4730-Rural Rate Assistance Expense	$ 161,093	$ 24,164	$ 160,817	$ 24,123	$ 156,366	$ 23,455	$ -	$ -
4750-Charges-LV	$ 91,000	$ 13,650	$ 89,000	$ 13,350	$ 87,086	$ 13,063	$ 52,755	$ 7,913
Total Expenses for Working Capital	**$ 13,116,153**		**$ 13,068,422**		**$ 11,816,910**		**$ 10,460,480**	
Working Capital factor	**15%**		**15%**		**15%**		**15%**	
Working Capital Allowance	**$ 1,967,423**	**$ 1,967,423**	**$ 1,960,263**	**$ 1,960,263**	**$ 1,772,537**	**$ 1,772,537**	**$ 1,569,072**	**$ 1,569,072**

Overview

Overview of Operating Revenue

This Exhibit provides the details of the Applicant's operating revenue for 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Bridge Year and 2009 Test Year. This Exhibit also provides a detailed variance analysis by rate class of the operating revenue components.

Distribution revenues have been calculated using the rates approved in the OEB's 2008 rate adjustment proceeding in respect to the Applicant. In particular, delivery rates are based on the OEB's Decision and Order in EB-2007-0814, dated April 21, 2008. Distribution revenue does not include revenue from commodity or other pass through rates.

A summary of operating revenues is presented in Exhibit 3, Tab 1, Schedule 2.

Distribution Revenue:
Information related to the Applicant's distribution revenue includes details such as weather normalized forecasting methodology, normalized volume and customer count forecast tables. Detailed variance analysis on the forecast information is also provided. Detailed information relating to distribution revenue is set out in the Schedules to Exhibit 3, Tab 2.

Other Distribution Revenue:
Other revenues include Distribution Service Admin charge, Miscellaneous Service Revenues, Late Payment Charges, Other Operating Revenue, Other Income & Deduction and Interest Income. A summary of these operating revenues together with a materiality analysis of variances is presented in Exhibit 3, Tab 3, Schedules 1 and 2.

Revenue Sharing:

As noted in Exhibit 3, Tab 4, Schedule 1, the Applicant does not have a revenue sharing practice in place.

Summary of Operating Revenue Table

Table 1

Distribution Revenues	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2007 Actual	Variance from 2006 Actual	2008 Bridge	Variance from 2007 Actual	2009 Test	Variance from 2008 Bridge
Residential	1,392,176	1,486,138	93,962	1,489,356	3,218	1,543,668	54,312	1,544,673	1,005
General Service Less Than 50 kW	443,141	471,626	28,485	469,588	(2,038)	487,074	17,486	479,621	(7,453)
General Service 50 to 2,999 kW	472,288	390,851	(81,437)	404,217	13,366	383,420	(20,797)	531,238	147,818
General Service 3,000 to 4,999 kW	55,306	29,953	(25,353)	30,844	891	54,409	23,565	89,042	34,633
Unmetered Scattered Load	-	-	-	5,522	5,522	7,491	1,969	10,959	3,468
Sentinel Lighting	397	461	64	460	(1)	418	(42)	2,027	1,609
Street Lighting	5,163	10,214	5,051	10,392	178	6,519	(3,873)	82,193	75,674
	2,368,471	2,389,243	20,772	2,410,379	21,136	2,482,999	72,620	2,739,753	256,754
Other Distribution Revenue									
Distribution Services Admin Chrg	25,966	20,196	(5,770)	20,106	(90)	20,937	831	21,335	398
Service Revenue	30,056	14,205	(15,851)	14,805	600	12,482	(2,323)	12,422	(60)
Late Payment Charges	9,757	11,511	1,754	10,144	(1,367)	10,373	229	10,373	-
Other Operating Revenue	81,683	123,634	41,951	141,133	17,499	134,713	(6,420)	135,613	900
Other Income & Deduction	40,738	8,321	(32,417)	52,746	44,425	9,072	(43,674)	4,700	(4,372)
Interest Income	100,848	261,418	160,570	263,280	1,862	152,513	(110,767)	151,000	(1,513)
	289,048	439,285	150,237	502,214	62,929	340,090	(162,124)	335,443	(4,647)
Total Operating Revenue	2,657,519	2,828,528	171,009	2,912,593	84,065	2,823,089	(89,504)	3,075,196	252,107

Variance Analysis on Operating Revenue

The Applicant's distribution revenue has been calculated using its most recently approved rates. In particular, delivery rates are based on the EB-2007-0814 Rate Order, dated April 21, 2008. As noted above, distribution revenue does not include commodity-related revenue.

A summary of normalized operating revenues is presented in Exhibit 3, Tab 1, Schedule 2.

2006 Board Approved:

The Applicant's 2006 Board Approved operating revenue was forecast to be $2,657,519 as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totaled $2,368,471 or 89.1% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $289,048.

2006 Actual:

The Applicant's operating revenue in fiscal 2006 was $2,828,528 as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totaled $2,389,243 or 84.5% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $439,285.

Comparison to 2006 Board Approved:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue was $171,009 higher than the 2006 Board Approved level forecasted. This increase was a result of an increase in Distribution Revenues of $20,772 and an increase of Other Revenue of $150,237. The increase in Distribution Revenues was due to an increase in demand. The fluctuation between the classes was due to the transformer allowance being allocated to all of the classes in the 2006 Board Approved results. The transformer allowance was correctly reflected in the 2006 actual results. See Exhibit 3, Tab 3, Schedule 2 for an explanation of the increase in Other Revenue.

2007 Actual:

The Applicant's operating revenue in fiscal 2007 was $2,912,593, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totaled $2,410,379 or 82.8% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $502,214.

Comparison to 2006 Actual:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue was $84,065 higher than the 2006 Board Approved level forecasted. This increase was a result of an increase in Distribution Revenues of $21,136 and an increase of Other Revenue of $62,929. The increase in Distribution Revenues was due to an increase in demand. See Exhibit 3, Tab 3, Schedule 2 for an explanation of the increase in Other Revenue.

2008 Bridge Year:

The Applicant's operating revenue is forecast to be $2,823,089 in fiscal 2008, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $2,482,999 or 88.0% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $340,090.

Comparison to 2007 Actual:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue in 2008 is expected to be $89,504 less than the actual year level in fiscal 2007. This decrease is the result of the demand driven increase in Distribution Revenues of $72,620 being offset by a substantial decrease in Other Revenue of $162,124. For an explanation of this variance, see Exhibit 3, Tab 3, Schedule 2.

2009 Test Year:

The Applicant's operating revenue is forecast to be $3,075,196 in fiscal 2009, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $2,739,753 or 89.1% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $335,443.

Comparison to 2008 Bridge Year:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is expected to be $252,107 higher than the bridge year level in fiscal 2008. This increase is the result of an increase in Distribution Revenues of $256,754 which is explained below. There is a decrease of Other Revenue of $4,647. See Exhibit 3, Tab 3, Schedule 2.

The Distribution Revenue variances are due to the applicant's initiative to bring the Revenue to Cost ratio closer to 1, as described in Exhibit 8 – Cost Allocation. This explains all variance with the exception of General Service 50 to 2,999 kW class and General Service 3,000 to 4,999 kW class

The increase in the General Service 50 to 2,999 kW class, of $147,818, is due partly to the Revenue to Cost ratio adjustment, as described above. Also, this class was assigned a higher percentage of Total Revenue, 19.39% as compared to 17.19%, from the Cost Allocation filing.

The increase in the General Service 3,000 to 4,999 kW class, of $34,633, is due partly to the Revenue to Cost ratio adjustment, as described above, as well as a slight increase in demand.

Distribution Revenue

Weather Normalized Forecasting Methodology

This exhibit discusses the methodology used to determine Centre Wellington Hydro's customer and load forecast. Centre Wellington Hydro contracted with Elenchus Research Associates, known as ERA, to provide weather normalized load forecasts for 2008 and 2009 data as part of its rebase filing and projections for the number of customers in each customer class for both the 2008 Bridge Year and the 2009 Test Year. Historical data for the annual number of customers in each rate class is available for 2002 through to 2007 and are displayed in the Exhibit 3, Tab 2, Schedule 2. The ERA report prepared for Centre Wellington Hydro to support Exhibit 3 is included at Exhibit 3, Tab 2, Schedule 9.

As required by the OEB's Filing Requirements, Centre Wellington Hydro is providing normalized historical and forecast (Bridge Year and Test Year) throughput data. Weather normalization is based on normalized 10 year average (1998-2007) of heating and cooling degree days from Pearson International Airport. The model also considers economic (employment) and timing (peak days) variables in determining forecast values for weather sensitive classes.
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Economic and Forecast Assumptions

Customer Forecast:

The table below presents historical and forecast customer numbers, by class, for Centre Wellington Hydro. Historical numbers are the average annual number of active customer connections in each class. Forecasts are based on a trend forecast for annual customers based on the average customer additions from 2003 and 2007. No additional customer connections are expected for intermediate, street lighting, sentinel lighting, or USL customer classes.

Customer By Class (as at Year End)

Table 1

	2002	2003	2004	2005	2006	2007	2008 Bridge	2009 Test
Residential	4,986	5,163	5,319	5,400	5,467	5,510	5,522	5,710
% Change		3.5%	3.0%	1.5%	1.2%	0.8%	0.2%	3.4%
General Service Less Than 50 kW	624	615	627	624	640	673	673	687
% Change		-1.4%	2.0%	-0.5%	2.6%	5.2%	0.0%	2.1%
General Service 50 to 2,999 kW	50	52	55	52	50	55	56	53
% Change		4.0%	5.8%	-5.5%	-3.8%	10.0%	1.8%	-5.4%
General Service 3,000 to 4,999 kW	2	1	1	1	1	1	1	1
% Change		-50.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Unmetered Scattered Load	2	2	2	2	2	2	2	2
% Change		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Sentinel Lighting	25	25	33	24	25	33	35	35
% Change		0.0%	32.0%	-27.3%	4.2%	32.0%	6.1%	0.0%
Street Lighting	1,494	1,513	1,568	1,562	1,557	1,654	1,658	1,658
% Change		1.3%	3.6%	-0.4%	-0.3%	6.2%	0.2%	0.0%

Customer and Load Forecast

Table 2

Class	UOM	2006 Approved	2006 Actual	2007 Actual	2007 Normalized	2008 Normalized	2008 Estimated	2009 Normalized
Residential	# of Cust	5,319	5,466	5,510	5,494	5,601	5,522	5,710
	kWh	44,667,222	44,088,207	44,472,195	44,678,018	44,886,175	44,547,272	45,046,630
General Service Less Than 50 kW	# of Cust	627	639	671	662	674	673	687
	kWh	21,764,491	21,783,627	21,593,159	21,690,859	21,758,916	21,271,948	21,809,071
General Service 50 to 2,999 kW	# of Cust	55	52	55	53	53	56	53
	kW	178,990	164,033	163,893	163,893	165,368	168,573	166,526
	kWh	60,099,753	63,960,748	63,421,042	63,421,042	63,991,831	64,829,029	64,439,774
General Service 3,000 to 4,999 kW	# of Cust	1	1	1	1	1	1	1
	kW	44,060	40,351	43,181	43,181	43,569	44,426	43,874
	kWh	20,715,955	19,020,065	20,647,752	20,647,752	20,833,582	21,330,447	20,979,417
Unmetered Scattered Load	# of Cust	-	2	2	2	2	2	2
	kWh		377,657	400,443	400,443	400,443	403,818	400,443
Sentinel Lighting	# of Cust	33	25	33	35	35	35	35
	kW	157	130	127	127	124	128	122
	kWh	56,769	46,931	45,574	45,574	44,655	45,974	43,755
Street Lighting	# of Cust	1,568	1,557	1,654	1,658	1,658	1,658	1,658
	kW	3,156	3,118	3,092	3,092	3,079	3,143	3,066
	kWh	1,095,671	1,130,200	1,121,884	1,121,884	1,117,298	1,139,942	1,112,732

Normalized Volume Forecast Table

The Applicant has provided the following table of the normalized volume forecast by customer class by year:

Table 1

Rate Classes	kWh /kW	2006 Board Approved	2006 Actual Normalized	Variance from 06 Board Approved	2007 Actual Normalized	Variance from 06 Normalized	2008 Bridge Normalized	Variance from 2007 Normalized	2009 Test Normalized	Variance from 08 Normalized
Residential	kWh	44,667,222	44,940,022	272,800	44,678,018	(262,004)	44,886,175	208,157	45,046,630	160,455
General Service Less Than 50 kW	kWh	21,764,491	21,769,063	4,572	21,690,859	(78,204)	21,758,916	68,057	21,809,071	50,155
General Service 50 to 2,999 kW	kWh	60,099,753	63,960,748	3,860,995	63,421,042	(539,706)	63,991,831	570,789	64,439,774	447,943
General Service 50 to 2,999 kW	kW	178,990	164,033	(14,957)	163,893	(140)	165,368	1,475	166,526	1,158
General Service 3,000 to 4,999 kW	kWh	20,715,955	19,020,065	(1,695,890)	20,647,752	1,627,687	20,833,582	185,830	20,979,417	145,835
General Service 3,000 to 4,999 kW	kW	44,060	40,351	(3,709)	43,181	2,830	43,569	388	43,874	305
Unmetered Scattered Load	kWh	-	377,657	377,657	400,443	22,786	400,443	-	400,443	-
Sentinel Lighting	kWh	56,769	46,931	(9,838)	45,574	(1,357)	44,655	(919)	43,755	(900)
Sentinel Lighting	kW	157	130	(27)	127	(3)	124	(3)	122	(2)
Street Lighting	kWh	1,095,671	1,130,200	34,529	1,121,884	(8,316)	1,117,298	(4,586)	1,112,732	(4,566)
Street Lighting	kW	3,156	3,118	(38)	3,092	(26)	3,079	(13)	3,066	(13)
Total	kWh	148,399,861	151,244,686	2,844,825	152,005,572	760,886	153,032,900	1,027,328	153,831,822	798,922
Total	kW	226,363	207,632	(18,731)	210,293	2,661	212,140	1,847	213,588	1,448

Variance Analysis on Normalized Volume Forecast

For each of the Historical, Bridge and Test Years, the sum of the normalized volumes for the Residential, GS less than 50 kW, GS 50 kW to 2,999 kW and GS 3,000 kW to 4,999 kW classes represents 99% of Centre Wellington Hydro's total volume in the year. Analysis of the variance on normalized volume for these four classes is presented below.

2006 Board Approved vs. 2006 Actual – Normalized

The most recent Historical Board Approved values are from 2006. The percentage variations between the 2006 Board approved and 2006 normalized kWh by class are presented in the following table.

Residential	0.61%
GS less than 50 kW	0.02%
GS 50 kW to 2,999 kW	6.42%
GS 3,000 kW to 4,999 kW	-8.19%

The sum of the above classes' kWh consumption represents 99.0% of total Centre Wellington Hydro volume in 2006. The increase in Residential was due to a new subdivision added in 2006. The GS 50 kW to 2,999 kW class increased substantially from 2006 Board Approved. This was due to several businesses increasing production since 2002, with 2 or 3 businesses having substantial increases. The GS 3,000 kW to 4,999 kW decreased as the Applicant lost one (1) customer with monthly consumption of 1.6 to 2.0 million kWh in 2002, which affected the 2006 Board Approved results.

2006 Actual – Normalized vs. 2007 Actual– Normalized

The percentage variations between the 2006 normalized and 2007 normalized kWh by class are presented in the following table.

Residential	-0.58%
GS less than 50 kW	-0.36%
GS 50 kW to 2,999 kW	-0.84%
GS 3,000 kW to 4,999 kW	8.56%

The sum of the Residential, GS < 50 kW and GS > 50 kW classes' kWh consumption represents 99.0% of total Centre Wellington Hydro volume in 2007. The GS 3,000 to 4,999 kWh class experienced higher volumes due to the increased production of the customer in this class.

2007 Actual – Normalized vs. 2008 Bridge Year – Normalized

The percentage variations between the 2007 normalized and 2008 normalized kWh by class are presented in the following table.

Residential	0.47%
GS less than 50 kW	0.31%
GS 50 kW to 2,999 kW	0.90%
GS 3,000 kW to 4,999 kW	0.90%

The sum of the Residential, GS < 50 kW and GS > 50 kW classes' kWh consumption represents 99.0% of total Centre Wellington Hydro volume in 2008.

2008 Bridge Year – Normalized vs. 2009 Test Year

The percentage variations between the 2008 normalized and 2009 forecast kWh by class are presented in the following table.

Residential	0.36%
GS less than 50 kW	0.23%
GS 50 kW to 2,999 kW	0.70%
GS 3,000 kW to 4,999 kW	0.70%

The sum of the Residential, GS less than 50 kW and GS 50 kW to 2,999 kW classes' kWh consumption represents 99.0% of total Centre Wellington Hydro volume in 2009.

Customer Count Forecast Table

The following Table sets out the Applicant's customer counts at year end for 2006 Board Approved, 2006 Actual, 2007 Actual, the 2008 Bridge Year and the 2009 Test Year, together with corresponding variances.

Customer Count Forecast

Table 1

	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2007 Actual	Variance from 2006 Actual	2008 Bridge	Variance from 2007 Actual	2009 Test	Variance from 2008 Bridge
Residential	5,319	5,466	147	5,510	44	5,522	12	5,710	188
General Service Less Than 50 kW	627	639	12	673	34	673	-	687	14
General Service 50 to 2,999 kW	55	52	(3)	55	3	56	1	53	(3)
General Service 3,000 to 4,999 kW	1	1	-	1	-	1	-	1	-
Unmetered Scattered Load	2	2	-	2	-	2	-	2	-
Sentinel Lighting	33	25	(8)	33	8	35	2	35	-
Street Lighting	1,568	1,557	(11)	1,654	97	1,658	4	1,658	-
Total	7,605	7,742	137	7,928	186	7,947	19	8,146	199

Variance Analysis on Customer Count Forecast

For each of the Historical, Bridge and Test Years, the sum of the customer count for the Residential, GS less than 50 kW, GS 50 kW to 2,999 kW and GS 3,000 kW to 4,999 kW class represented approximately 99% of Centre Wellington Hydro's total volume in the year. Analysis of the variance on customer counts is limited to these four classes and is presented below.

2006 Historical Board Approved vs. 2006 Actual

The most recent Historical Board Approved values are from 2004. The percentage variations between the 2006 Board approved and 2006 customer counts by class are presented in the following table.

Residential	2.77%
GS less than 50 kW	1.91%
GS 50 kW to 2,999 kW	-5.45%
GS 3,000 kW to 4,999 kW	0.00%

The customer growth over this period appears normal. The GS 50 to 2,999 kW class decreased by only 3 customers.

2006 Actual vs. 2007 Actual

The percentage variations between the 2006 Actual and 2007 Actual customer counts by class are presented in the following table.

Residential	0.80%
GS less than 50 kW	5.77%
GS 50 kW to 2,999 kW	5.77%
GS 3,000 kW to 4,999 kW	0.00%

Except for the GS less than 50 kWh, the customer growth over this period appears normal. In the GS less than 50 kWh, the increase in customers was due to the development of an

industrial park in Fergus. Also bulk metered customer changed to individual meters, causing an increase to the customer count.

2007 Actual vs. 2008 Bridge

The percentage variations between the 2007 and 2008 customer counts by class are presented in the following table.

Residential	0.22%
GS less than 50 kW	0.00%
GS 50 kW to 2,999 kW	1.82%
GS 3,000 kW to 4,999 kW	0.00%

The customer growth over this period appears normal.

2008 Bridge vs. 2009 Test Year

The percentage variations between the 2008 and 2009 forecast customer counts by class are presented in the following table.

Residential	3.40%
GS less than 50 kW	2.08%
GS 50 kW to 2,999 kW	-5.36%
GS 3,000 kW to 4,999 kW	0.00%

The customer growth over this period appears normal

Historical Average Consumption

The following table sets out historical and average consumption for each of Centre Wellington Hydro's customer classes:

Historical Average Consumption (kWh)

Table 1

		Weather Normalized	Average # of Customers	Average Consumption per Customer	Net Change in Average Consumption per Customer
Residential					
	2002	41,764,893	4,879	8,560	
	2003	42,621,737	5,087	8,379	(182)
	2004	43,329,690	5,236	8,275	(103)
	2005	44,238,573	5,364	8,247	(28)
	2006	44,940,022	5,435	8,269	21
	2007	44,678,018	5,494	8,132	(136)
	2008	44,886,175	5,601	8,014	(118)
	2009	45,046,630	5,710	7,889	(125)
General Service Less Than 50 kW					
	2002	20,587,574	623	33,046	
	2003	20,899,067	615	33,982	936
	2004	21,184,864	615	34,447	465
	2005	21,505,827	621	34,631	184
	2006	21,769,063	629	34,609	(22)
	2007	21,690,859	662	32,766	(1,843)
	2008	21,758,916	674	32,283	(482)
	2009	21,809,071	687	31,745	(538)
General Service 50 to 2,999 kW					
	2002	55,612,546	53	1,049,293	
	2003	57,081,918	53	1,077,017	27,724
	2004	60,906,157	52	1,171,272	94,255
	2005	61,284,669	52	1,178,551	7,279
	2006	63,960,748	52	1,230,014	51,463
	2007	63,421,042	53	1,196,623	(33,391)
	2008	63,991,831	53	1,207,393	10,770
	2009	64,439,774	53	1,215,845	8,452

General Service 3,000 to 4,999 kW		Weather Normalized	Average # of Customers	Average Consumption per Customer	Net Change in Average Consumption per Customer
	2002	32,707,525	4	8,176,881	
	2003	24,031,645	3	8,010,548	(166,333)
	2004	23,978,633	2	11,989,317	3,978,768
	2005	22,594,949	2	11,297,475	(691,842)
	2006	19,020,065	1	19,020,065	7,722,591
	2007	20,647,752	1	20,647,752	1,627,687
	2008	20,833,582	1	20,833,582	185,830
	2009	20,979,417	1	20,979,417	145,835
Unmetered Scattered Load					
	2002	332,857	2	166,429	
	2003	336,913	2	168,457	2,028
	2004	333,555	2	166,778	(1,679)
	2005	337,533	2	168,767	1,989
	2006	377,657	2	188,829	20,062
	2007	400,443	2	200,222	11,393
	2008	400,443	2	200,222	0
	2009	400,443	2	200,222	0
Sentinel Lighting					
	2002	46,958	32	1,467	
	2003	47,786	32	1,493	26
	2004	48,229	32	1,507	14
	2005	47,473	34	1,396	(111)
	2006	46,931	35	1,341	(55)
	2007	45,574	35	1,302	(39)
	2008	44,655	35	1,276	(26)
	2009	43,755	35	1,250	(26)
Street Lighting					
	2002	1,072,074	1,585	676	
	2003	1,091,079	1,602	681	5
	2004	1,122,092	1,631	688	7
	2005	1,131,124	1,658	682	(6)
	2006	1,130,200	1,658	682	(1)
	2007	1,121,884	1,658	677	(5)
	2008	1,117,298	1,658	674	(3)
	2009	1,112,732	1,658	671	(3)
Total					
	2002	152,124,427	7,178	21,193	
	2003	146,110,145	7,394	19,761	(1,433)
	2004	150,903,220	7,570	19,934	174
	2005	151,140,148	7,733	19,545	(390)
	2006	151,244,686	7,812	19,361	(184)
	2007	152,005,572	7,905	19,229	(132)
	2008	153,032,900	8,024	19,072	(157)
	2009	153,831,822	8,146	18,884	(188)

Distribution Revenue Data By Class

2006 Board Approved	Customers (Year end)	Consumption/Demand (kWh/kW)		Distribution Revenues $	Unit Revenues $/kWh/kW
Residential	5,319	44,667,222	kWh	1,392,176	0.0312
General Service Less Than 50 kW	627	21,764,491	kWh	443,141	0.0204
General Service 50 to 2,999 kW	55	178,990	kW	472,288	2.6386
General Service 3,000 to 4,999 kW	1	44,060	kW	55,306	1.2552
Unmetered Scattered Load	2	-	kWh	-	
Sentinel Lighting	33	157	kW	397	2.5287
Street Lighting	1,568	3,156	kW	5,163	1.6359
Total	7,605			2,368,471	

2006 Actual	Customers (Year end)	Consumption/Demand (kWh/kW)		Distribution Revenues $	Unit Revenues $/kWh/kW
Residential	5,466	44,088,207	kWh	1,486,138	0.0337
General Service Less Than 50 kW	639	21,783,627	kWh	471,626	0.0217
General Service 50 to 2,999 kW	52	164,033	kW	390,851	2.3828
General Service 3,000 to 4,999 kW	1	40,351	kW	29,953	0.7423
Unmetered Scattered Load	2	377,657	kWh	-	0.0000
Sentinel Lighting	25	130	kW	461	3.5462
Street Lighting	1,557	3,118	kW	10,214	3.2758
Total	7,742			2,389,243	

2007 Actual	Customers (Year end)	Consumption/Demand (kWh/kW)		Distribution Revenues $	Unit Revenues $/kWh/kW
Residential	5,510	44,472,195	kWh	1,489,356	0.0335
General Service Less Than 50 kW	673	21,593,159	kWh	469,588	0.0217
General Service 50 to 2,999 kW	55	163,893	kW	404,217	2.4663
General Service 3,000 to 4,999 kW	1	43,181	kW	30,844	0.7143
Unmetered Scattered Load	2	400,443	kWh	5,522	0.0138
Sentinel Lighting	33	127	kW	460	3.6220
Street Lighting	1,654	3,092	kW	10,392	3.3609
Total	7,928			2,410,379	

Distribution Revenue Data By Class (Cont)

2008 Bridge Normalized	Customers (Year end)	Consumption/Demand (kWh/kW)		Distribution Revenues $	Unit Revenues $/kWh/kW
Residential	5,522	44,886,175	kWh	1,543,668	0.0344
General Service Less Than 50 kW	673	21,758,916	kWh	487,074	0.0224
General Service 50 to 2,999 kW	56	165,368	kW	383,420	2.3186
General Service 3,000 to 4,999 kW	1	43,569	kW	54,409	1.2488
Unmetered Scattered Load	2	400,443	kWh	7,491	0.0187
Sentinel Lighting	35	124	kW	418	3.3710
Street Lighting	1,658	3,079	kW	6,519	2.1172
Total	7,947			2,482,999	

2009 Test Normalized	Customers (Year end)	Consumption/Demand (kWh/kW)		Distribution Revenues $	Unit Revenues $/kWh/kW
Residential	5,710	45,046,630	kWh	1,544,673	0.0343
General Service Less Than 50 kW	687	21,809,071	kWh	479,621	0.0220
General Service 50 to 2,999 kW	53	166,526	kW	531,238	3.1901
General Service 3,000 to 4,999 kW	1	43,874	kW	89,042	2.0295
Unmetered Scattered Load	2	400,443	kWh	10,959	0.0274
Sentinel Lighting	35	122	kW	2,027	16.6148
Street Lighting	1,658	3,066	kW	82,193	26.8079
Total	8,146			2,739,753	

ERA – Weather Normalization System Load Forecast

Medium Term Weather Normalized Distribution System Load Forecast
2008 to 2009

Prepared for

Centre Wellington Hydro Ltd.

June 6, 2008

1 INTRODUCTION

This document outlines the results and methodology used to derive the weather normal load forecast prepared for use in Centre Wellington Hydro Ltd.'s rebasing rate application for 2009 rates. A weather normal load forecast is developed for the bridge year (2008) and test year (2009) and weather normalized historical consumption is also derived.

For the most part, the forecast for Centre Wellington Hydro is based on monthly class specific retail data from January 2002 to December 2007. The retail metered data has been prorated to represent calendar month consumption. That is, the billing data has been adjusted to account for unbilled amounts, the effect of meter reading dates, etc. The retail consumption amounts do not include losses; therefore, distribution system losses are not part of the class retail volumes. These volumes will need to be adjusted for distribution system losses to reconcile with wholesale purchases by the LDC.

Short-term variation in electricity consumption is heavily influenced by three main factors – weather (e.g. heating and cooling), which is by far the 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 tried to incorporate variables to account for all of these factors in considering Centre Wellington's load and correcting for weather anomalies.

In order to isolate demand determinants at the class specific level, we have estimated equations to weather normalize and forecast kWh consumption for the residential and GS<50 classes. In analysing Centre Wellington's GS>50 class data, we have determined that consumption in this class is not correlated with weather (see details below). Consumption for the intermediate class, street lighting, sentinel lighting, and unmetered scattered load (USL) is also not weather sensitive. The forecast for lighting and unmetered loads is based on trend consumption. Consumption for GS>50 kW class and the intermediate class is based on the forecast employment trend. We have

calculated the class kW demand (where applicable) by applying an annual average kW/kWh ratio based on historical values to annual class kWh. Results are outlined in Section 2 below.

2 CLASS SPECIFIC NORMALIZED AND FORECAST RESULTS

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 Centre Wellington, we have used monthly HDD and CDD as reported at Pearson International Airport (YYZ) near Toronto.

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 Kitchener-Waterloo-Barrie economic region, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM series v2054776).

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 1* below.

Table 1
Monthly Peak Days

	2002	2003	2004	2005	2006	2007
January	22	21	21	20	21	22
February	20	20	20	20	20	20
March	20	21	23	21	23	22
April	21	20	20	21	18	19
May	22	21	20	21	22	22
June	20	21	22	22	22	21
July	22	22	21	20	20	22
August	21	20	21	22	22	22
September	20	21	21	21	20	19
October	22	22	20	20	21	22
November	21	20	22	22	22	22
December	20	21	21	20	19	19
	Full-time employment ('000s) Kit-Wat-Barrie, Ontario					
January	446.2	467.1	487.3	508.9	519.2	529.2
February	447.6	464.2	484.4	507.7	517.6	520.2
March	449.1	463.4	483.5	503.0	517.8	514.6
April	455.2	467.9	483.2	503.4	522.2	512.1
May	460.2	477.4	489.5	513.2	530.1	512.2
June	466.6	482.9	498.3	521.6	537.6	523.0
July	473.9	489.7	509.8	531.3	547.6	537.9
August	478.5	497.1	515.2	537.9	555.4	549.6
September	475.1	498.3	515.8	537.0	553.9	548.0
October	469.5	499.2	509.3	530.4	550.0	541.9
November	464.1	493.0	504.4	522.4	542.5	536.1
December	467.9	490.8	506.2	521.6	538.6	535.2
Ann % chg	***1.1%***	***4.3%***	***3.4%***	***4.2%***	***3.1%***	***-1.1%***

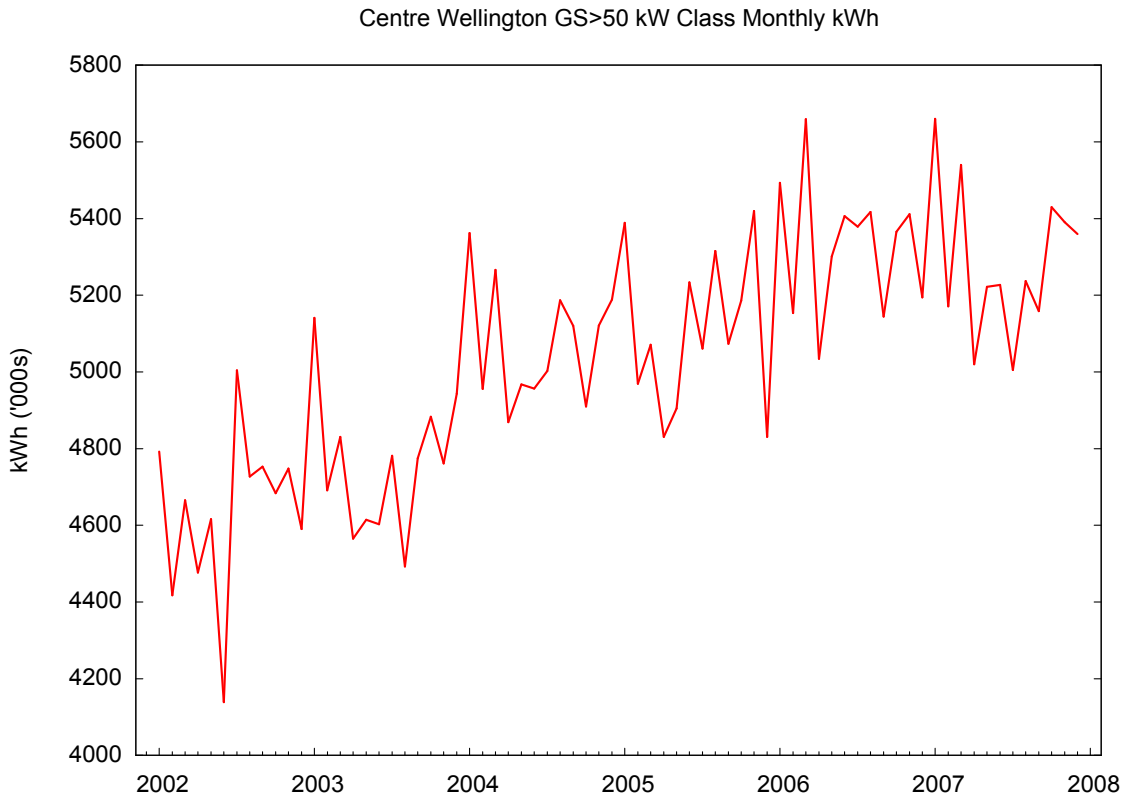
Using this data, regression equations describing the relationship between monthly actual energy and the explanatory variables were estimated for residential and GS<50 classes. In analyzing the GS>50 kW class monthly kWh, the monthly profile did not appear to be particularly well correlated with observed weather. A correlation matrix of GS > 50 kW class monthly kWh, monthly HDD and monthly CDD is displayed in *Table 2* below:

Table 2 Correlation coefficients, using the observations 2002:01 - 2007:12
5% critical value (two-tailed) = 0.2319 for n = 72

GS>50 kWh	HDD	CDD	
1.0000	0.1142	0.0064	GS>50 kWh
	1.0000	-0.7127	HDD
		1.0000	CDD

Chart 1 below displays the monthly data, which does not display the typical profile for weather sensitive load.

Chart 1



The results for residential and GS<50 consumption show strong correlation with weather, as expected. Centre Wellington's residential kWh consumption is influenced by weather and economic factors (employment). Peak days did not show a statistically significant influence (which is not atypical for residential load).

Results for Residential kWh

Res kWh = f(HDD, CDD, Employ) + const

OLS estimates using the 72 observations 2002:01-2007:12

Unadjusted R^2 =0.87891
Adjusted R^2 = 0.873568
F-statistic (3, 68) = 164.523 (p-value < 0.00001)
Durbin-Watson statistic = 1.70521

Variable Name	Estimated Coeff.	T-Ratio	P-Value
const	917,250.0	2.6621	0.00968
HDD	2,268.3	21.926	<0.00001
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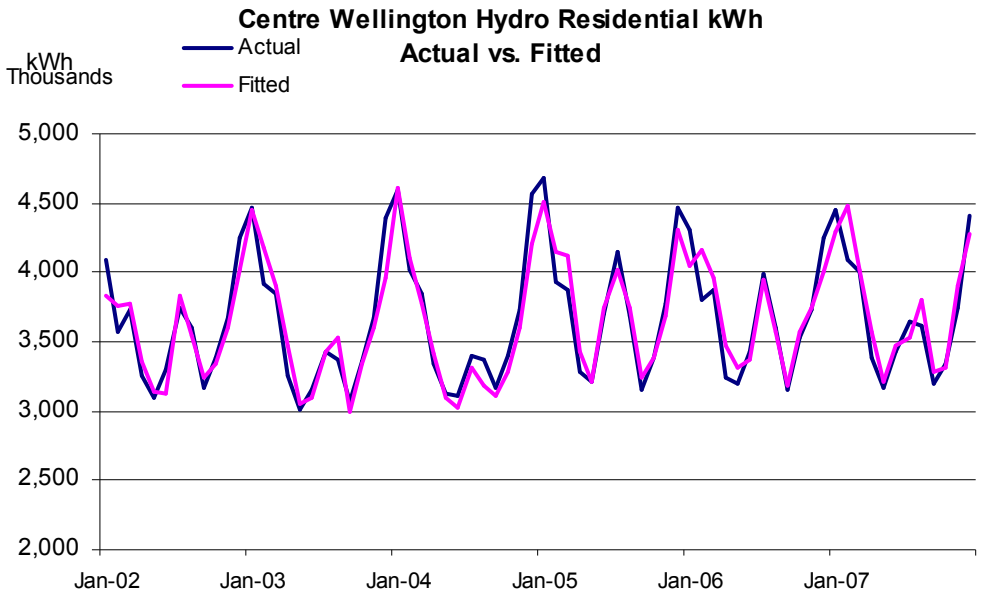
Actual and fitted values are plotted in the chart below:



Energy consumption in the GS<50 kW class correlated with weather as well as peak days and economic factors (employment).

Results for GS < 50 kW Class kWh

GS<50 kWh = *f*(HDD, CDD, Peak days, Employ) + const

OLS estimates using the 72 observations 2002:01-2007:12

Unadjusted R^2 = 0.86721
Adjusted R^2 = 0.859282
F-statistic (4, 67) = 109.389 (p-value < 0.00001)
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Variable Name	Estimated Coeff.	T-Ratio	P-Value
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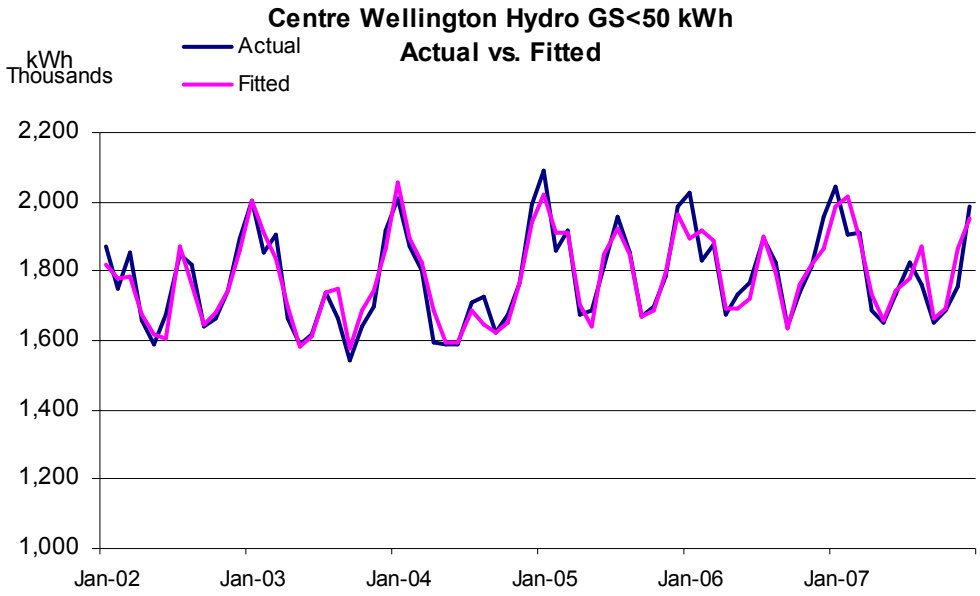

Annual estimates are compared to actual values in the table below. Mean absolute percentage error (MAPE) of the estimates for the period are less than 1 per cent.

Table 3 – Centre Wellington Hydro – Annual Predicted vs. Actual

Year	*Actual Residential kWh*	*Predicted kWh*	*Error*	*Actual GS<50 kWh*	*Predicted kWh*	*Error*
2002	42,855,989	42,571,213	-0.66%	21,014,593	20,858,193	-0.74%
2003	42,912,312	43,011,952	0.23%	20,843,216	21,002,992	0.77%
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2007	44,472,195	45,167,347	1.56%	21,593,159	21,848,224	1.18%
		Mean Absolute Percent Error	*0.95%*			*0.65%*

2.1 WEATHER NORMALIZATION AND FORECASTED CONSUMPTION

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 Centre Wellington, 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 Pearson International Airport (YYZ).

Table 4 – 30-yr and 10-yr HDD and CDD, Pearson Int'l Airport (YYZ)

	1971-2000 30yr normal		1998-2007 10yr normal	
	HDD	**CDD**	**HDD**	**CDD**
Jan	752.9	0.0	700.3	0.0
Feb	662.1	0.0	609.2	0.0
Mar	571.6	0.0	531.4	0.0
Apr	353.3	1.1	320.2	1.2
May	171.8	12.0	143.4	15.0
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Oct	282.6	1.0	237.7	4.3
Nov	445.5	0.0	397.4	0.0
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Annual	**4,065.8**	**252.1**	**3,631.0**	**390.0**

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 5 - Employment Forecast – Ontario (figures in annual percentage change)

	BMO *(Winter 2008)*	RBC *(April 2008)*	Scotia *(May 5, 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, monthly peak days, and 10-yr weather normal heating and cooling degree days, the following weather corrected consumption and forecast values are calculated:

Table 6 - Weather Corrected Consumption for Centre Wellington				
			10-yr (1998-2007)	
Year	Actual residential kWh	%chg	Weather Normal	%chg
2002	42,855,989		41,764,893	
2003	42,912,312	0.1%	42,621,737	2.1%
2004	43,665,814	1.8%	43,329,690	1.7%
2005	45,304,934	3.8%	44,238,573	2.1%
2006	44,088,207	-2.7%	44,940,022	1.6%
2007	44,472,195	0.9%	44,678,018	-0.6%
2008F			44,886,175	0.5%
2009F			45,046,630	0.4%
Year	Actual GS<50 kWh	%chg	Weather Normal	%chg
2002	21,014,593		20,587,574	
2003	20,843,216	-0.82%	20,899,067	1.5%
2004	20,956,433	0.54%	21,184,864	1.4%
2005	21,985,494	4.91%	21,505,827	1.5%
2006	21,783,627	-0.92%	21,769,063	1.2%
2007	21,593,159	-0.87%	21,690,859	-0.4%
2008F			21,758,916	0.3%
2009F			21,809,071	0.2%

2.2 NON-WEATHER SENSITIVE CLASS FORECASTS

Historic and forecast class consumption for non-weather sensitive classes (GS>50 kW, Intermediate, Street Lighting, Sentinel Lighting, and USL) are displayed in Table 7 below. Class kW forecast values (where applicable) are calculated by determining an annual kW/kWh ratio and multiplying this ratio by the forecast kWh in the year. Forecast values are based on the kW/kWh ratio in 2007. Forecasts for the GS>50 kW class and the intermediate (>3000 kW) class are projected based on the employment trend forecast for Ontario in 2008 and 2009. The street and sentinel lighting classes are forecast based on the trend of consumption over the past two historic years (2006 and 2007). USL consumption is held constant at the 2007 level. The growth in 2006 and 2007 was due to due to an upgrade in a single customer's system. No further growth is anticipated in 2008 and 2009.

The large drop in consumption in the intermediate class in 2003 is due to the loss of a customer in 2002 that consumed approximately 1.6 to 2.0 million kWh per month.[1]

Table 7 – GS>50 kW Class, Intermediate Class, Lighting and USL

	GS > 50				*Intermediate*			
Year	kWh	%	kW	%	kWh	%	kW	%
2002	55,612,546		150,536		32,707,425		74,023	
2003	57,081,918	2.6%	151,088	0.4%	24,031,645	-26.5%	52,554	-29.0%
2004	60,906,157	6.7%	157,975	4.6%	23,978,633	-0.2%	53,373	1.6%
2005	61,284,669	0.6%	158,770	0.5%	22,594,949	-5.8%	50,047	-6.2%
2006	63,960,748	4.4%	164,033	3.3%	19,020,065	-15.8%	40,351	-19.4%
2007	63,421,042	-0.8%	163,893	-0.1%	20,647,752	8.6%	43,181	7.0%
2008F	63,991,831	0.9%	165,368	0.9%	20,833,582	0.9%	43,569	0.9%
2009F	64,439,774	0.7%	166,526	0.7%	20,979,417	0.7%	43,874	0.7%

	Street Lighting				*Sentinel Lighting*			
Year	kWh	%	kW	%	kWh	%	kW	%
2002	1,072,074		2,993		46,958		130	
2003	1,091,079	1.8%	3,010	0.5%	47,786	1.8%	133	1.8%
2004	1,122,092	2.8%	3,091	2.7%	48,229	0.9%	134	0.9%
2005	1,131,124	0.8%	3,120	0.9%	47,473	-1.6%	132	-1.6%
2006	1,130,200	-0.1%	3,118	-0.1%	46,931	-1.1%	130	-1.1%
2007	1,121,884	-0.7%	3,092	-0.8%	45,574	-2.9%	127	-2.9%
2008F	1,117,298	-0.4%	3,079	-0.4%	44,655	-2.0%	124	-2.0%
2009F	1,112,732	-0.4%	3,066	-0.4%	43,755	-2.0%	122	-2.0%

	USL	
Year	kWh	%
2002	332,857	
2003	336,913	1.2%
2004	333,555	-1.0%
2005	337,533	1.2%
2006	377,657	11.9%
2007	400,443	6.0%
2008F	400,443	0.0%
2009F	400,443	0.0%

Table 8 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).

[1] The customer relocated operations outside of Ontario.

Table 8 – Load Forecast (Historical, Bridge and Test Years).

	2007 Actual	2007 Normalized	2008f Normalized	2009f Normalized
Residential (kWh)	44,472,195	44,678,018	44,886,175	45,046,630
GS<50 (kWh)	21,593,159	21,690,859	21,758,916	21,809,071
GS>50 (kWh)	63,421,042	63,421,042	63,991,831	64,439,774
(kW)	163,893	163,893	165,368	166,526
Intermediate (kWh)	20,647,752	20,647,752	20,833,582	20,979,417
(kW)	43,181	43,181	43,569	43,874
Street Lights (kWh)	1,121,884	1,121,884	1,117,298	1,112,732
(kW)	3,092	3,092	3,079	3,066
Sentinel Lights (kWh)	45,574	45,574	44,655	43,755
(kW)	127	127	124	122
USL (kWh)	400,443	400,443	400,443	400,443
Total Retail kWh	151,702,049	152,005,572	153,032,901	153,831,822

CUSTOMER CONNECTIONS

Table 9 below outlines the average annual number of active customer connections in each class and a trend forecast for annual customers based on the average customer additions from 2003 and 2007. No additional customer connections are expected for intermediate, street lighting, sentinel lighting, or USL customer classes.

Table 9 – Average Annual Customer Connections

	Residential	%chg	GS<50	%chg	GS>50	%chg	Intermed.	Street Light	Sent Light	USL
2002	4,879		623				4	1,585	32	2
2003	5,087	*4.3%*	615	*-1.3%*	53		3	1,602	32	2
2004	5,236	*2.9%*	615	*0.0%*	52	*-0.9%*	2	1,631	32	2
2005	5,364	*2.4%*	621	*0.9%*	52	*-1.0%*	2	1,658	34	2
2006	5,435	*1.3%*	629	*1.3%*	52	*1.0%*	1	1,658	35	2
2007	5,494	*1.1%*	662	*5.2%*	53	*1.1%*	1	1,658	35	2
2006-2007		**1.9%**		**1.9%**		**0.0%**				
2008f	5,601		674		53		1	1,658	35	2
2009f	5,710		687		53		1	1,658	35	2

Medium Term Weather Normalized Distribution System Load Forecast
2008 to 2009

Prepared for

Centre Wellington Hydro Ltd.

June 6, 2008

1 INTRODUCTION

This document outlines the results and methodology used to derive the weather normal load forecast prepared for use in Centre Wellington Hydro Ltd.'s rebasing rate application for 2009 rates. A weather normal load forecast is developed for the bridge year (2008) and test year (2009) and weather normalized historical consumption is also derived.

For the most part, the forecast for Centre Wellington Hydro is based on monthly class specific retail data from January 2002 to December 2007. The retail metered data has been prorated to represent calendar month consumption. That is, the billing data has been adjusted to account for unbilled amounts, the effect of meter reading dates, etc. The retail consumption amounts do not include losses; therefore, distribution system losses are not part of the class retail volumes. These volumes will need to be adjusted for distribution system losses to reconcile with wholesale purchases by the LDC.

Short-term variation in electricity consumption is heavily influenced by three main factors – weather (e.g. heating and cooling), which is by far the 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 tried to incorporate variables to account for all of these factors in considering Centre Wellington's load and correcting for weather anomalies.

In order to isolate demand determinants at the class specific level, we have estimated equations to weather normalize and forecast kWh consumption for the residential and GS<50 classes. In analysing Centre Wellington's GS>50 class data, we have determined that consumption in this class is not correlated with weather (see details below). Consumption for the intermediate class, street lighting, sentinel lighting, and unmetered scattered load (USL) is also not weather sensitive. The forecast for lighting and unmetered loads is based on trend consumption. Consumption for GS>50 kW class and the intermediate class is based on the forecast employment trend. We have

calculated the class kW demand (where applicable) by applying an annual average kW/kWh ratio based on historical values to annual class kWh. Results are outlined in Section 2 below.

2 CLASS SPECIFIC NORMALIZED AND FORECAST RESULTS

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 Centre Wellington, we have used monthly HDD and CDD as reported at Pearson International Airport (YYZ) near Toronto.

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 Kitchener-Waterloo-Barrie economic region, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM series v2054776).

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 1* below.

Table 1
Monthly Peak Days

	2002	2003	2004	2005	2006	2007
January	22	21	21	20	21	22
February	20	20	20	20	20	20
March	20	21	23	21	23	22
April	21	20	20	21	18	19
May	22	21	20	21	22	22
June	20	21	22	22	22	21
July	22	22	21	20	20	22
August	21	20	21	22	22	22
September	20	21	21	21	20	19
October	22	22	20	20	21	22
November	21	20	22	22	22	22
December	20	21	21	20	19	19
	Full-time employment ('000s) Kit-Wat-Barrie, Ontario					
January	446.2	467.1	487.3	508.9	519.2	529.2
February	447.6	464.2	484.4	507.7	517.6	520.2
March	449.1	463.4	483.5	503.0	517.8	514.6
April	455.2	467.9	483.2	503.4	522.2	512.1
May	460.2	477.4	489.5	513.2	530.1	512.2
June	466.6	482.9	498.3	521.6	537.6	523.0
July	473.9	489.7	509.8	531.3	547.6	537.9
August	478.5	497.1	515.2	537.9	555.4	549.6
September	475.1	498.3	515.8	537.0	553.9	548.0
October	469.5	499.2	509.3	530.4	550.0	541.9
November	464.1	493.0	504.4	522.4	542.5	536.1
December	467.9	490.8	506.2	521.6	538.6	535.2
Ann % chg	***1.1%***	***4.3%***	***3.4%***	***4.2%***	***3.1%***	***-1.1%***

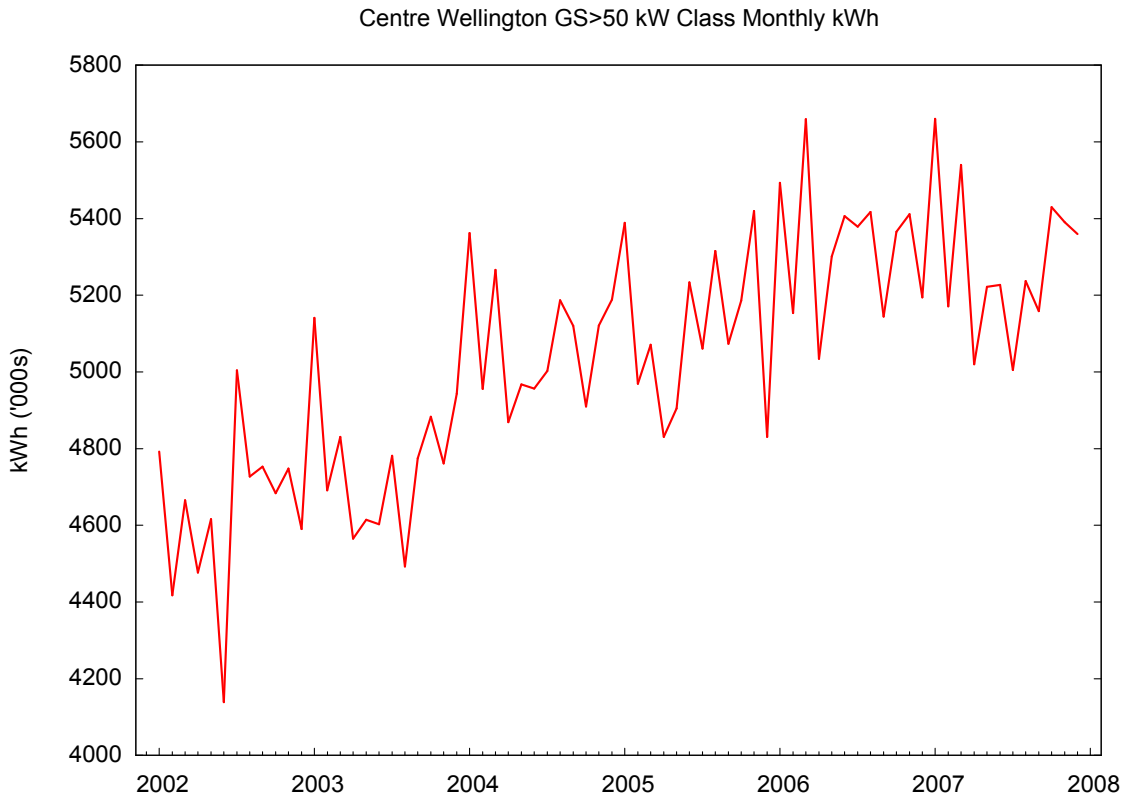
Using this data, regression equations describing the relationship between monthly actual energy and the explanatory variables were estimated for residential and GS<50 classes. In analyzing the GS>50 kW class monthly kWh, the monthly profile did not appear to be particularly well correlated with observed weather. A correlation matrix of GS > 50 kW class monthly kWh, monthly HDD and monthly CDD is displayed in *Table 2* below:

Table 2 Correlation coefficients, using the observations 2002:01 - 2007:12
5% critical value (two-tailed) = 0.2319 for n = 72

GS>50 kWh	HDD	CDD	
1.0000	0.1142	0.0064	GS>50 kWh
	1.0000	-0.7127	HDD
		1.0000	CDD

Chart 1 below displays the monthly data, which does not display the typical profile for weather sensitive load.

Chart 1



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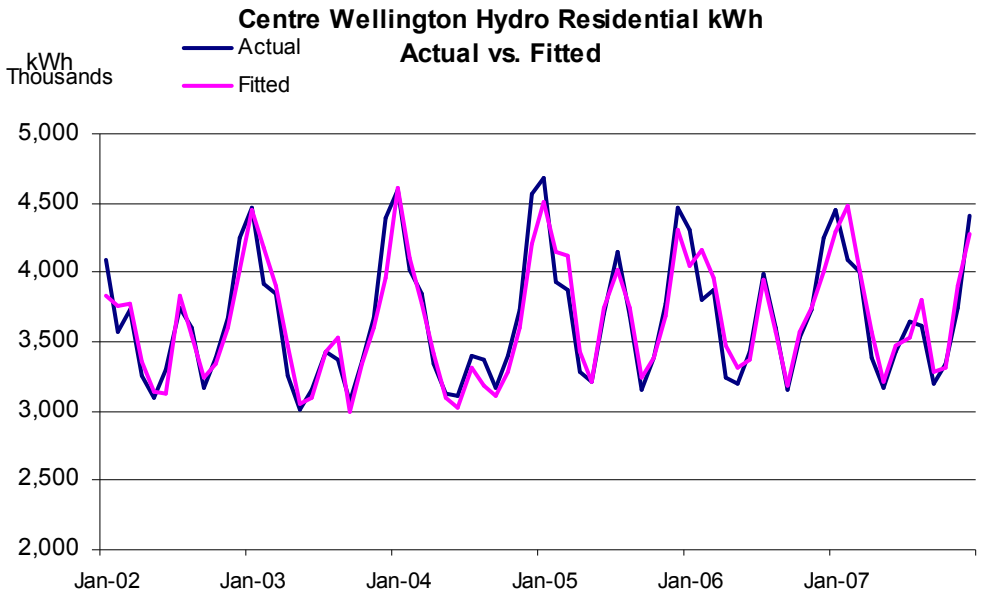

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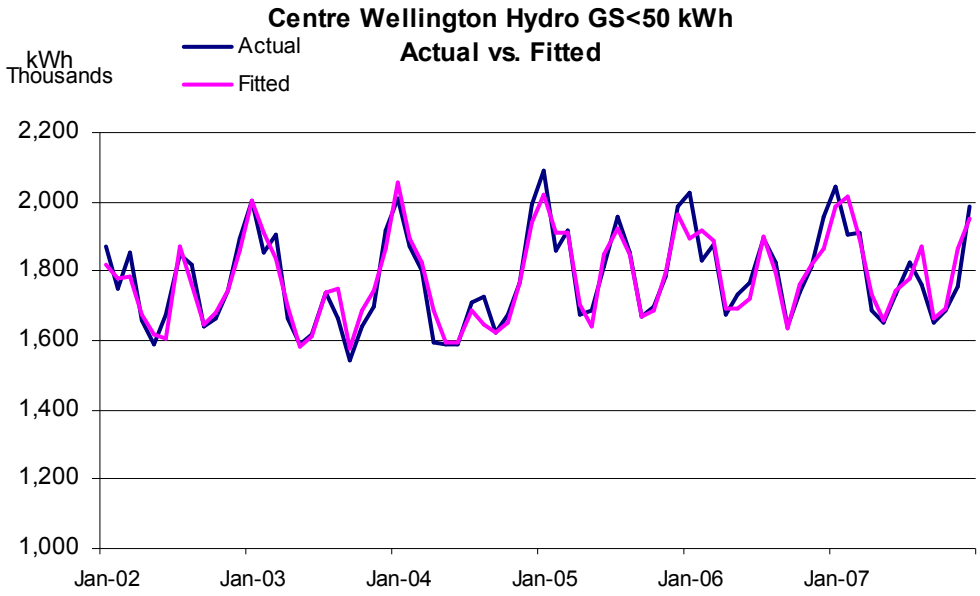

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Forecasts for Ontario's employment outlook for 2008 and 2009 are available from four Canadian Chartered Banks at time of writing. Their forecasts are summarized below.

Table 5 - Employment Forecast – Ontario (figures in annual percentage change)

	BMO *(Winter 2008)*	RBC *(April 2008)*	Scotia *(May 5, 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, monthly peak days, and 10-yr weather normal heating and cooling degree days, the following weather corrected consumption and forecast values are calculated:

Table 6 - Weather Corrected Consumption for Centre Wellington				
			10-yr (1998-2007)	
Year	Actual residential kWh	%chg	Weather Normal	%chg
2002	42,855,989		41,764,893	
2003	42,912,312	0.1%	42,621,737	2.1%
2004	43,665,814	1.8%	43,329,690	1.7%
2005	45,304,934	3.8%	44,238,573	2.1%
2006	44,088,207	-2.7%	44,940,022	1.6%
2007	44,472,195	0.9%	44,678,018	-0.6%
2008F			44,886,175	0.5%
2009F			45,046,630	0.4%
Year	Actual GS<50 kWh	%chg	Weather Normal	%chg
2002	21,014,593		20,587,574	
2003	20,843,216	-0.82%	20,899,067	1.5%
2004	20,956,433	0.54%	21,184,864	1.4%
2005	21,985,494	4.91%	21,505,827	1.5%
2006	21,783,627	-0.92%	21,769,063	1.2%
2007	21,593,159	-0.87%	21,690,859	-0.4%
2008F			21,758,916	0.3%
2009F			21,809,071	0.2%

2.2 NON-WEATHER SENSITIVE CLASS FORECASTS

Historic and forecast class consumption for non-weather sensitive classes (GS>50 kW, Intermediate, Street Lighting, Sentinel Lighting, and USL) are displayed in Table 7 below. Class kW forecast values (where applicable) are calculated by determining an annual kW/kWh ratio and multiplying this ratio by the forecast kWh in the year. Forecast values are based on the kW/kWh ratio in 2007. Forecasts for the GS>50 kW class and the intermediate (>3000 kW) class are projected based on the employment trend forecast for Ontario in 2008 and 2009. The street and sentinel lighting classes are forecast based on the trend of consumption over the past two historic years (2006 and 2007). USL consumption is held constant at the 2007 level. The growth in 2006 and 2007 was due to due to an upgrade in a single customer's system. No further growth is anticipated in 2008 and 2009.

The large drop in consumption in the intermediate class in 2003 is due to the loss of a customer in 2002 that consumed approximately 1.6 to 2.0 million kWh per month.[1]

Table 7 – GS>50 kW Class, Intermediate Class, Lighting and USL

	GS > 50				*Intermediate*			
Year	kWh	%	kW	%	kWh	%	kW	%
2002	55,612,546		150,536		32,707,425		74,023	
2003	57,081,918	2.6%	151,088	0.4%	24,031,645	-26.5%	52,554	-29.0%
2004	60,906,157	6.7%	157,975	4.6%	23,978,633	-0.2%	53,373	1.6%
2005	61,284,669	0.6%	158,770	0.5%	22,594,949	-5.8%	50,047	-6.2%
2006	63,960,748	4.4%	164,033	3.3%	19,020,065	-15.8%	40,351	-19.4%
2007	63,421,042	-0.8%	163,893	-0.1%	20,647,752	8.6%	43,181	7.0%
2008F	63,991,831	0.9%	165,368	0.9%	20,833,582	0.9%	43,569	0.9%
2009F	64,439,774	0.7%	166,526	0.7%	20,979,417	0.7%	43,874	0.7%

	Street Lighting				*Sentinel Lighting*			
Year	kWh	%	kW	%	kWh	%	kW	%
2002	1,072,074		2,993		46,958		130	
2003	1,091,079	1.8%	3,010	0.5%	47,786	1.8%	133	1.8%
2004	1,122,092	2.8%	3,091	2.7%	48,229	0.9%	134	0.9%
2005	1,131,124	0.8%	3,120	0.9%	47,473	-1.6%	132	-1.6%
2006	1,130,200	-0.1%	3,118	-0.1%	46,931	-1.1%	130	-1.1%
2007	1,121,884	-0.7%	3,092	-0.8%	45,574	-2.9%	127	-2.9%
2008F	1,117,298	-0.4%	3,079	-0.4%	44,655	-2.0%	124	-2.0%
2009F	1,112,732	-0.4%	3,066	-0.4%	43,755	-2.0%	122	-2.0%

	USL	
Year	kWh	%
2002	332,857	
2003	336,913	1.2%
2004	333,555	-1.0%
2005	337,533	1.2%
2006	377,657	11.9%
2007	400,443	6.0%
2008F	400,443	0.0%
2009F	400,443	0.0%

Table 8 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).

[1] The customer relocated operations outside of Ontario.

Table 8 – Load Forecast (Historical, Bridge and Test Years).

	2007 Actual	2007 Normalized	2008f Normalized	2009f Normalized
Residential (kWh)	44,472,195	44,678,018	44,886,175	45,046,630
GS<50 (kWh)	21,593,159	21,690,859	21,758,916	21,809,071
GS>50 (kWh)	63,421,042	63,421,042	63,991,831	64,439,774
(kW)	163,893	163,893	165,368	166,526
Intermediate (kWh)	20,647,752	20,647,752	20,833,582	20,979,417
(kW)	43,181	43,181	43,569	43,874
Street Lights (kWh)	1,121,884	1,121,884	1,117,298	1,112,732
(kW)	3,092	3,092	3,079	3,066
Sentinel Lights (kWh)	45,574	45,574	44,655	43,755
(kW)	127	127	124	122
USL (kWh)	400,443	400,443	400,443	400,443
Total Retail kWh	151,702,049	152,005,572	153,032,901	153,831,822

CUSTOMER CONNECTIONS

Table 9 below outlines the average annual number of active customer connections in each class and a trend forecast for annual customers based on the average customer additions from 2003 and 2007. No additional customer connections are expected for intermediate, street lighting, sentinel lighting, or USL customer classes.

Table 9 – Average Annual Customer Connections

	Residential	%chg	GS<50	%chg	GS>50	%chg	Intermed.	Street Light	Sent Light	USL
2002	4,879		623				4	1,585	32	2
2003	5,087	*4.3%*	615	*-1.3%*	53		3	1,602	32	2
2004	5,236	*2.9%*	615	*0.0%*	52	*-0.9%*	2	1,631	32	2
2005	5,364	*2.4%*	621	*0.9%*	52	*-1.0%*	2	1,658	34	2
2006	5,435	*1.3%*	629	*1.3%*	52	*1.0%*	1	1,658	35	2
2007	5,494	*1.1%*	662	*5.2%*	53	*1.1%*	1	1,658	35	2
2006-2007		**1.9%**		**1.9%**		**0.0%**				
2008f	5,601		674		53		1	1,658	35	2
2009f	5,710		687		53		1	1,658	35	2

Other Distribution Revenue

Summary of Other Distribution Revenue

Other Distribution Revenue	2006 Board Approved	2006 Actual	2006 vs 2006 Approved	2007 Actual	2007 vs. 2006	2008 Bridge	2008 vs 2007	2009 Test	2009 vs 2008
4080-SSS Administration Charge	25,966	20,196	(5,770)	20,106	(90)	20,937	831	21,335	398
4082-Retail Services Revenues	11,074	13,683	2,609	13,967	284	12,180	(1,787)	12,120	(60)
4084-Service Transaction Requests (STR) Revenues	11	521	510	838	317	302	(536)	302	-
4090-Electric Services Incidental to Energy Sales	18,971	-	(18,971)	-	-	-	-	-	-
4210-Rent from Electric Property	20,478	63,848	43,370	15,493	(48,355)	15,493	-	15,493	-
4225-Late Payment Charges	9,757	11,511	1,754	10,144	(1,367)	10,373	229	10,373	-
4235-Miscellaneous Service Revenues	61,205	59,786	(1,419)	125,640	65,854	119,220	(6,420)	120,120	900
4325-Revenues from Merchandise,Jobbing	215	3,908	3,693	10,647	6,739	3,000	(7,647)	3,000	-
4355-Gain on Disposition of Utility & Other	35,669	1,340	(34,329)	38,386	37,046	4,372	(34,014)	-	(4,372)
4360-Loss on Disposition of Utility & Other	(777)	-	777	-	-	-	-	-	-
4390-Miscellaneous Non-Operating Income	5,631	3,074	(2,557)	3,713	639	1,700	(2,013)	1,700	-
4405-Interest and Dividend Income	100,848	261,418	160,570	263,280	1,862	152,513	(110,767)	151,000	(1,513)
Total	289,048	439,285	150,237	502,214	62,929	340,090	(162,124)	335,443	(4,647)

Materiality and Variance Analysis on Other Distribution Revenue

Preamble:

The Materiality threshold used to analyze Other Distribution Revenue was the threshold used for OM&A costs, being 1 per cent of total distribution expenses before PILs as set out in Table 3.3.2-1 below. The OM&A cost threshold was used because other distribution revenues, like OM&A costs, are recorded in Income Statement accounts.

Table 1

	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Total Distribution Expenses before PILs	$2,364,740	$2,434,867	$2,754,746	$2,850,845
Materiality Threshold	$23,677	$24,349	$27,547	$28,508

To allow for the most detailed review of materiality on Other Distribution Revenue, Centre Wellington Hydro has selected the lowest materiality threshold of $23,677. Centre Wellington Hydro has provided explanations for the following variances, which exceed the materiality threshold. The following variances exceed the materiality threshold.

2006 Board Approved To 2006 Actual

Account	2006 Board Approved	2006 Actual	*Variance*
4210- Rent from Electric Property	$20,478	$63,848	$43,370
4355-Gain on Disposition	$35,669	$1,340	($34,329)
4405- Interest and Dividend Income	$100,848	$261,418	$160,570

Explanation:

The variance in account 4210-Rent from Electric Property of $43,370 is due to posting “Specific Charge for Access to Power Poles” to account 4210 instead of 4235 – Misc Service Revenues

The $34,329 variance in account 4355 is due to a gain on sale of the surplus Aerial Truck which was replaced in 2004; this revenue was reflected in the 2006 EDR.

The variance in account 4405 – Interest & Dividend Income was the result of an increase in Interest Revenue of $160,570. This was due to increased interest rates (from 2.75% to 4.5%)

and an increase in bank balance (from $4,006,670 to $5,393,822). This interest variance represents 93.9% of the total operating revenue variance.

2006 Actual To 2007 Actual

Account	2006 Actual	2007 Actual	*Variance*
4210- Rent from Electric Property	$63,848	$15,493	($48,355)
4235-Misc Service Revenue	$59,786	$125,640	$65,854
4355-Gain on Disposition	$1,340	$38,386	$37,046

Explanation:

The variance resulting from account 4210-Rent from Electric Property (-$48,355) is due to "Specific Charges for Access to the Power Poles" being moved to account 4235 in 2007. This is consistent with posting all Specific Service charges to account "4235 – Misc Service Revenues". The variance for Acct 4235, $65,854, is mainly due to a combination of the reallocation of the "Specific Charges for Access to the Power Poles" from Acct 4210 ($48,355); the increase in Account Setup charge effective May 1, 2006 from $10.00 to $30.00 for a net increase in revenue of $9,230 and an increase in revenue of $7,044 generated from the approved Notification charge of $30.00 per notice.

The $37,046 variance in Acct 4355 is due to a gain on sale of the surplus transportation equipment of $38,386 in 2007.

2007 Actual To 2008 Bridge

Account	2007 Actual	2008 Bridge	*Variance*
4355-Gain on Disposition	$38,386	$4,372	($34,014)
4405- Interest and Dividend Income	$263,280	$152,513	($110,767)

Explanation:

The decrease in Acct 4355 – "Gain on Disposition" of $34,014 is due to a gain on sale of surplus transportation equipment of $38,386 in 2007.

The decrease in revenue in account 4405 – "Interest Income" of $110,767 is due to a decrease in the prime interest rate and the transfer of Retained Earnings in the amount of $2,000,000 to a holding company in the last quarter of 2008.

2008 Bridge to 2009 Test

Account	2008 Bridge	2009 Test	*Variance*
4405- Interest and Dividend Income	$152,513	$151,000	-$1,513
4355-Gain on Disposition of Utility	$4,372	0	-$4,372

Explanation:

There are no material variances when comparing 2009 Test Year to 2008 Bridge Year. However, account 4405-Interest and Dividend Income saw a decrease of $1,513 which is immaterial and account 4355-Gain on Disposition of Utility Property saw a decrease of $4,372 because there are no planned disposals of assets at this time for 2009.

Rate of Return on Other Distribution Revenue

Other distribution revenues do not include a rate of return.

Revenue Sharing

Description of Revenue Sharing

Centre Wellington Hydro does not have a revenue sharing practice in place.

Overview

Overview of Operating Costs

Operating Costs

The operating costs presented in this exhibit represent the annual expenditures required to sustain the Applicant's operations.

OM&A Costs

The OM&A costs in this exhibit represent the expenditures needed to maintain the Applicant's integrated set of asset maintenance and customer activities 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 the cost of providing services to customers connected to the Applicant's distribution system, and the costs required to meet 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 conservative risk-based decision making to ensure that the most appropriate, cost effective solutions are put in place.

Income Tax, Large Corporation Tax and Ontario Capital Taxes

Tab 3 of this exhibit provides PILs calculations for the bridge and test years, a Capital Cost Allowance table for the relevant years of this rate application and corporate tax returns for 2006 and 2007.

Summary of Operating Costs

		2006 EDR Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
3500	Operations	$ 175,881	$ 218,322	$ 256,507	$ 284,900	$ 264,900
3550	Maintenance	$ 258,340	$ 247,085	$ 252,713	$ 296,200	$ 292,600
3650	Billing and Collecting	$ 285,425	$ 328,595	$ 314,401	$ 323,100	$ 332,200
3700	Community Relations	$ 21,753	$ 51,191	$ 42,778	$ 56,500	$ 35,600
3800	Administrative and General Expenses	$ 706,526	$ 588,417	$ 636,151	$ 739,200	$ 786,300
3950	Taxes Other Than Income	$ 30,832	$ 52,866	$ 31,436	$ 33,000	$ 35,000
	Total OM & A Costs	**$ 1,478,756**	**$ 1,486,476**	**$ 1,533,986**	**$ 1,732,900**	**$ 1,746,600**
3850	Amortization Expense	$ 510,349	$ 488,770	$ 511,313	$ 594,185	$ 638,185
	Total Distribution Expenses	**$ 1,989,105**	**$ 1,975,246**	**$ 2,045,299**	**$ 2,327,085**	**$ 2,384,785**
6110	LCT, OCT & Income Taxes	$ 138,385	$ 246,816	$ 451,826	$ 27,037	$ 10,466
	TOTAL OPERATING COSTS	**$ 1,850,721**	**$ 1,728,430**	**$ 1,593,473**	**$ 2,300,048**	**$ 2,374,319**

OM&A Costs

OM&A Costs Table

(Including Amortization)

Account Grouping	Account Description	2006 EDR	2006 Actual	Variance - 2006 Actual - EDR	2007 Actual	Variance - 2007 to 2006 Actual	2008 Bridge Year Projection	Variance 2008 Projection to 2007	2009 Test Year Projection	Variance 2009 Projection - 2008 Projection
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	$ 44,403	$ 70,850	$ 26,447	$ 97,211	$ 26,361	$ 92,000	$ (5,211)	$ 94,500	$ 2,500
	5010-Load Dispatching	$ 8,258	$ 12,887	$ 4,629	$ 16,600	$ 3,712	$ 17,400	$ 800	$ 18,200	$ 800
	5012-Station Buildings and Fixtures Expense	$ 27,749	$ 29,445	$ 1,696	$ 33,594	$ 4,149	$ 27,000	$ (6,594)	$ 29,400	$ 2,400
	5017-Distribution Station Equipment - Operation Supplies and Expenses	$ -	$ -	$ -	$ 7	$ 7	$ -	$ (7)	$ -	$ -
	5020-Overhead Distribution Lines and Feeders - Operation Labour	$ 1,237	$ 396	$ (841)	$ 416	$ 20	$ 950	$ 534	$ 1,200	$ 250
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$ -	$ 624	$ 624	$ -	$ (624)	$ 900	$ 900	$ -	$ (900)
	5030-Overhead Subtransmission Feeders - Operation	$ 757	$ 1,006	$ 249	$ 208	$ (798)	$ 950	$ 742	$ 1,000	$ 50
	5035-Overhead Distribution Transformers- Operation	$ 600	$ 191	$ (409)	$ 671	$ 480	$ 300	$ (371)	$ 1,600	$ 1,300
	5040-Underground Distribution Lines and Feeders - Operation Labour	$ 4,443	$ 1,782	$ (2,661)	$ 627	$ (1,155)	$ 700	$ 73	$ 3,100	$ 2,400
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$ 1,891	$ 406	$ (1,485)	$ 797	$ 391	$ 1,000	$ 203	$ 1,000	$ -
	5055-Underground Distribution Transformers - Operation	$ 339	$ 699	$ 360	$ 577	$ (122)	$ 7,200	$ 6,623	$ 1,000	$ (6,200)
	5060-Street Lighting and Signal System Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	5065-Meter Expense	$ 49,992	$ 54,097	$ 4,105	$ 70,404	$ 16,307	$ 87,400	$ 16,996	$ 62,500	$ (24,900)

	5070-Customer Premises - Operation Labour	$ 868	$ 1,122	$ 253	$ 1,166	$ 44	$ 1,100	$ (66)	$ 1,200	$ 100
	5075-Customer Premises - Materials and Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	5085-Miscellaneous Distribution Expense	$ 31,183	$ 36,098	$ 4,915	$ 29,869	$ (6,229)	$ 43,500	$ 13,631	$ 45,700	$ 2,200
	5090-Underground Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	5095-Overhead Distribution Lines and Feeders - Rental Paid	$ 4,159	$ -	$ (4,159)	$ 4,359	$ 4,359	$ 4,500	$ 141	$ 4,500	$ -
	5096-Other Rent	$ -	$ 8,719	$ 8,719	$ -	$ (8,719)	$ -	$ -	$ -	$ -
TOTAL 3500 - Distribution Expenses - Operation		**$ 175,881**	**$ 218,322**	**$ 42,442**	**$ 256,507**	**$ 38,185**	**$ 284,900**	**$ 28,393**	**$ 264,900**	**$ (20,000)**

1

Account Grouping	Account Description	2006 EDR	2006 Actual	Variance - 2006 Actual - EDR	2007 Actual	Variance - 2007 to 2006 Actual	2008 Bridge Year Projection	Variance 2008 Projection to 2007	2009 Test Year Projection	Variance 2009 Projection - 2008 Projection
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	$ 55,630	$ 42,061	$ (13,570)	$ 42,047	$ (13)	$ 50,500	$ 8,453	$ 52,600	$ 2,100
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	$ 1,499	$ 1,415	$ (84)	$ 1,153	$ (263)	$ 3,300	$ 2,147	$ 4,400	$ 1,100
	5114-Maintenance of Distribution Station Equipment	$ 883	$ (811)	$ (1,694)	$ 52,555	$ 53,366	$ 36,400	$ (16,155)	$ 44,800	$ 8,400
	5120-Maintenance of Poles, Towers and Fixtures	$ 32,579	$ 18,096	$ (14,483)	$ 7,872	$ (10,224)	$ 30,000	$ 22,128	$ 26,100	$ (3,900)
	5125-Maintenance of Overhead Conductors and Devices	$ 45,155	$ 41,025	$ (4,131)	$ 28,987	$ (12,038)	$ 51,800	$ 22,813	$ 47,800	$ (4,000)
	5130-Maintenance of Overhead Services	$ 30,705	$ 30,817	$ 112	$ 13,809	$ (17,008)	$ 14,600	$ 791	$ 13,700	$ (900)
	5135-Overhead Distribution Lines and Feeders - Right of Way	$ 40,898	$ 48,788	$ 7,890	$ 42,894	$ (5,894)	$ 41,400	$ (1,494)	$ 33,100	$ (8,300)
	5145-Maintenance of Underground Conduit	$ 1,456	$ 3,046	$ 1,591	$ 959	$ (2,087)	$ 5,300	$ 4,341	$ 5,700	$ 400
	5150-Maintenance of Underground Conductors and Devices	$ 120	$ 4,331	$ 4,211	$ 2,308	$ (2,023)	$ 3,900	$ 1,592	$ 5,800	$ 1,900
	5155-Maintenance of Underground Services	$ 20,880	$ 27,916	$ 7,036	$ 32,029	$ 4,114	$ 30,400	$ (1,629)	$ 27,000	$ (3,400)
	5160-Maintenance of Line Transformers	$ 24,254	$ 30,253	$ 5,999	$ 26,336	$ (3,916)	$ 27,100	$ 764	$ 30,000	$ 2,900
	5175-Maintenance of Meters	$ 4,280	$ 148	$ (4,132)	$ 1,764	$ 1,616	$ 1,500	$ (264)	$ 1,600	$ 100
Total 3550 - Distrbution Expenses - Maintenance		**$ 258,340**	**$ 247,085**	**$ (11,255)**	**$ 252,713**	**$ 5,629**	**$ 296,200**	**$ 43,487**	**$ 292,600**	**$ (3,600)**

3650-Billing and Collecting	5305-Supervision	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	5310-Meter Reading Expense	$ 41,903	$ 39,917	$ (1,986)	$ 39,452	$ (464)	$ 36,000	$ (3,452)	$ 36,100	$ 100
	5315-Customer Billing	$ 192,143	$ 219,626	$ 27,483	$ 213,142	$ (6,484)	$ 209,800	$ (3,342)	$ 231,000	$ 21,200
	5320-Collecting	$ 75,489	$ 68,951	$ (6,538)	$ 57,264	$ (11,687)	$ 73,700	$ 16,436	$ 61,500	$ (12,200)
	5325-Collecting- Cash Over and Short	$ 93	$ 21	$ (72)	$ (2)	$ (23)	$ 100	$ 102	$ 100	$ -
	5330-Collection Charges	$ (26,586)	$ -	$ 26,586	$ -	$ -	$ -	$ -	$ -	$ -
	5335-Bad Debt Expense	$ 2,365	$ 81	$ (2,284)	$ 4,546	$ 4,465	$ 3,500	$ (1,046)	$ 3,500	$ -
	5340-Miscellaneous Customer Accounts Expenses	$ 18	$ -	$ (18)	$ -	$ -	$ -	$ -	$ -	$ -
Total 3650 - Billing and Collecting		**$ 285,425**	**$ 328,595**	**$ 43,170**	**$ 314,401**	**$ (14,194)**	**$ 323,100**	**$ 8,699**	**$ 332,200**	**$ 9,100**

1

Account Grouping	Account Description	2006 EDR	2006 Actual	Variance - 2006 Actual - EDR	2007 Actual	Variance - 2007 to 2006 Actual	2008 Bridge Year Projection	Variance 2008 Projection to 2007	2009 Test Year Projection	Variance 2009 Projection - 2008 Projection
3700-Community Relations	5405-Supervision	$ -	$ 1,583	$ 1,583	$ 1,873	$ 290	$ 2,000	$ 127	$ 2,400	$ 400
	5410-Community Relations - Sundry	$ 9,748	$ 16,687	$ 6,939	$ 8,061	$ (8,626)	$ 42,300	$ 34,239	$ 3,800	$ (38,500)
	5415-Energy Conservation	$ -	$ 23,203	$ 23,203	$ 28,645	$ 5,442	$ 4,300	$ (24,345)	$ 9,600	$ 5,300
	5420-Community Safety Program	$ 3,250	$ -	$ (3,250)	$ -	$ -	$ -	$ -	$ 3,500	$ 3,500
	5425-Miscellaneous Customer Service and Informational Expenses	$ 8,755	$ 9,718	$ 963	$ 4,199	$ (5,519)	$ 7,900	$ 3,701	$ 16,300	$ 8,400
Total 3700 - Community Relations		**$ 21,753**	**$ 51,191**	**$ 29,438**	**$ 42,778**	**$ (8,413)**	**$ 56,500**	**$ 13,722**	**$ 35,600**	**$ (20,900)**
3800-Administrative and General Expenses	5610-Management Salaries and Expenses	$ 209,907	$ 222,403	$ 12,496	$ 243,537	$ 21,135	$ 257,000	$ 13,463	$ 263,800	$ 6,800
	5615-General Administrative Salaries and Expenses	$ 135,827	$ 129,478	$ (6,349)	$ 141,524	$ 12,046	$ 188,000	$ 46,476	$ 191,400	$ 3,400
	5620-Office Supplies and Expenses	$ 40,645	$ 42,876	$ 2,231	$ 41,546	$ (1,330)	$ 42,700	$ 1,154	$ 49,200	$ 6,500
	5630-Outside Services Employed	$ 55,873	$ 52,315	$ (3,557)	$ 34,578	$ (17,738)	$ 65,600	$ 31,022	$ 50,000	$ (15,600)
	5635-Property Insurance	$ 7,301	$ 10,757	$ 3,456	$ 11,022	$ 266	$ 11,000	$ (22)	$ 12,000	$ 1,000
	5640-Injuries and Damages	$ 19,069	$ 14,502	$ (4,567)	$ 31,761	$ 17,259	$ 29,000	$ (2,761)	$ 33,200	$ 4,200
	5645-Employee Pensions and Benefits	$ 7,724	$ (482)	$ (8,206)	$ 8,394	$ 8,876	$ 10,000	$ 1,606	$ 6,700	$ (3,300)
	5655-Regulatory Expenses	$ 23,024	$ 24,266	$ 1,242	$ 27,016	$ 2,749	$ 25,800	$ (1,216)	$ 65,200	$ 39,400

	5660-General Advertising Expenses	$ 1,051	$ 2,391	$ 1,340	$ 1,229	$ (1,162)	$ 1,300	$ 71	$ 1,500	$ 200
	5665-Miscellaneous General Expenses	$ 194,927	$ 69,717	$ (125,209)	$ 73,041	$ 3,323	$ 81,500	$ 8,459	$ 85,300	$ 3,800
	5670-Rent	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	5675-Maintenance of General Plant	$ 11,177	$ 12,567	$ 1,389	$ 16,341	$ 3,774	$ 19,500	$ 3,159	$ 19,000	$ (500)
	5680-Electrical Safety Authority Fees	$ -	$ 7,626	$ 7,626	$ 6,161	$ (1,465)	$ 7,800	$ 1,639	$ 9,000	$ 1,200
Total 3800 - Administrative and General Expenses		**$ 706,526**	**$ 588,417**	**$ (118,108)**	**$ 636,151**	**$ 47,733**	**$ 739,200**	**$ 103,049**	**$ 786,300**	**$ 47,100**
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	$ 30,832	$ 52,866	$ 22,034	$ 31,436	$ (21,430)	$ 33,000	$ 1,564	$ 35,000	$ 2,000
Total 3950 - Taxes Other Than Income Taxes		**$ 30,832**	**$ 52,866**	**$ 22,034**	**$ 31,436**	**$ (21,430)**	**$ 33,000**	**$ 1,564**	**$ 35,000**	**$ 2,000**
3850-Amortization	5705 - Amortization	$ 510,349	$ 488,770	$ (21,580)	$ 511,313	$ 22,543	$ 594,185	$ 82,872	$ 638,184	$ 43,999
Total - Amortization		**$ 510,349**	**$ 488,770**	**$ (21,580)**	**$ 511,313**	**$ 22,543**	**$ 594,185**	**$ 82,872**	**$ 638,184**	**$ 43,999**
TOTAL		**$ 1,989,105**	**$ 1,975,246**	**$ (13,859)**	**$ 2,045,299**	**$ 70,053**	**$ 2,327,085**	**$ 281,786**	**$ 2,384,784**	**$ 57,699**

Materiality and Variance Analysis on OM&A Costs

The following table provides the materiality values for variance analysis purposes for OM & A.

		2006 EDR Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
3500	Operations	$ 175,881	$ 218,322	$ 256,507	$ 284,900	$ 264,900
3550	Maintenance	$ 258,340	$ 247,085	$ 252,713	$ 296,200	$ 292,600
3650	Billing and Collecting	$ 285,425	$ 328,595	$ 314,401	$ 323,100	$ 332,200
3700	Community Relations	$ 21,753	$ 51,191	$ 42,778	$ 56,500	$ 35,600
3800	Administrative and General Expenses	$ 706,526	$ 588,417	$ 636,151	$ 739,200	$ 786,300
	Total OM & A Costs	**$ 1,447,924**	**$ 1,433,610**	**$ 1,502,550**	**$ 1,699,900**	**$ 1,711,600**
3950	Taxes Other Than Income	$ 30,832	$ 52,866	$ 31,436	$ 33,000	$ 35,000
	Total OM & A Costs	**$ 1,478,756**	**$ 1,486,476**	**$ 1,533,986**	**$ 1,732,900**	**$ 1,746,600**
3850	Amortization Expense	$ 510,349	$ 488,770	$ 511,313	$ 594,185	$ 638,185
	Total Distribution Expenses	**$ 1,989,105**	**$ 1,975,246**	**$ 2,045,299**	**$ 2,327,085**	**$ 2,384,785**
	Materiality at 1% of Dist Expenses	**$ 19,891**	**$ 19,752**	**$ 20,453**	**$ 23,271**	**$ 23,848**

Centre Wellington Hydro will use the lowest materiality level of $19,752 in order to provide more detail and review of costs.

2006 Board Approved EDR VS 2006 Actual

Total OM&A Expenses decreased in 2006 by $13,859 over 2006 Board Approved EDR balances. Those expenses whose materiality level exceeded 1% in 2006 vs. the 2006 EDR are set out.

Account Grouping: 3500-Distribution Expenses – Operations

The total variance between the 2006 EDR and the Actual 2006 Expenses is an increase of $42,442 of which $39,741 is explained below.

Acct # & Name	2006 EDR	2006 Actual	Variance
#5005-Operation Supervision & Engineering	$44,403	$70,850	$26,447
#5010-Load Dispatching	$8,258	$12,887	$4,629
#5065-Meter Expense	$49,992	$54,097	$4,105

#5095-Overhead Distribution Lines and Feeders – Rental Paid	$4,159	0	-$4,159
#5096-Other Rent	$0	$8,719	$8,719

Explanation:

The board approved data generated in the EDR filing based on very dated data based on 2002 to 2004 costs. As well, in July 2006, more hours were spent in this category preparing for the ESA audit. Consequently account number 5105 saw a decrease, as regular hours worked were allocated to 5005. In addition during 2006 staff had a closer watch on allocation of hours on the timesheets to ensure time spent is more accurately tracked.

Account 5010 – Load Dispatching – increased by $4,629 because the Applicant in completing the 2006 EDR found an inconsistency in posting of labour and overheads and started to implement steps to correct these problems. This cost-allocation refinement will continue to show fluctuations in the non-incremental wages/salaries until that portion of the financial system upgrade is completed in 2010.

In 2010 the Applicant has scheduled the implementation of the final phase of the financial software. This phase is for the operational side of the business and includes work orders, asset management and job costing.

Account 5095 - OH Distribution Lines – Rental Paid – showed a decrease of $4,159 because of fees paid for hydro wires on Bell Canada and Hydro One Networks poles, which was posted to account 5096 – Other Rent, in Error.

Account 5096 – Other Rent – showed an increase of $8,719 because rent paid to Bell Canada and Hydro One Networks poles was posted to this account in error, plus the 2006 figures included rent for both 2005 and 2006 because of non receipt of 2005 invoice until 2006.

Account 5065 – Meter Expense increased by $4,105 because of additional labour and overhead required to complete the necessary meter verifications required by Measurement Canada – the Applicant has deferred all changes of meters until Measurement Canada sent a letter indicating they need to be done immediately regardless of the implementation of smart meters.

Account Grouping: 3550-Distribution Expenses – Maintenance

The total variance between the 2006 EDR and the Actual 2006 Expenses is a decrease $11,255 of which $13,570 is explained below.

Acct # & Name	2006 EDR	2006 Actual	Variance
#5105-Maintenance Supervision and Engineering	$55,630	$42,060	-$13,570

Explanation:

The decrease in 5105 – Maintenance Supervision and Engineering was due to staff time originally allocated to this account in the previous year being transferred to 5005-Operations Supervision and Engineering in order to generate standards to meet ESA requirements and to prepare for the first ESA audit.

The other accounts in this section increased and decreased due to where the work was required for that year. Because no new labour had taken place, a variance appeared where time was allocated.

Account Grouping: 3650-Billing and Collecting

The total variance between the 2006 EDR and the Actual 2006 Expenses is an increase of $43,170 of which $54,069 is explained below.

Acct # & Name	2006 EDR	2006 Actual	Variance
#5315-Customer Billing	$192,143	$219,626	$27,483
#5330-Collection Charges	-$26,586	$0	$26,586

Explanation:

Account 5315 – Customer Billing - In 2006 the Applicant changed their ASP vendor for the billing system. A co operative model was adopted to get more functionality and be able to offer more service offerings to the customer in the future. For a short period of time there was an overlap of services for the two ASP Providers to ensure a successful transition. The Applicant saw an increase in postage prices, as well as an increase in bills being sent out, which accounted for the $3,988 increase compared to 2005 actual, with 2006 EDR being based on dated data this number would be even greater. An additional increase was due to a billing clerk attending a specialized training conference to prepare for the transition to the new version of

CIS software. This accounts for the $5,472. Also included was an increase in total salary paid to the billing clerk to cover additional hours worked to prepare for these changes.

The Applicant also saw an increase in computer expenses due to the IT vendor's time spent on creating specialized reports to assist in the transition from one ASP provider to another, as well as the standardization of setups.

Account 5330 – Collection Charges $26,586 were transferred to Revenues (Acct 4235) as per OEB Directions.

Account Grouping: 3700-Community Relations

The total variance between the 2006 EDR and the Actual 2006 Expenses is an increase of $29,438, of which $30,142 is explained below.

Acct # & Name	2006 EDR	2006 Actual	Variance
#5410-Community Relations Sundry	$9,748	$16,687	$6,939
#5415-Energy Conservation	$0	$23,203	$23,203

Explanation:

Account 5410 – Community Relations – Sundry increased by $6,939. This increase was due to the staff building a visual display to demonstrate to customers the difference in using energy efficient lights bulbs and appliances vs. the older non-energy efficient lights and appliances.

In 2006, the Applicant included in account 5415-Energy Conservation part of the funds that related to the "third tranche" on CDM programs as set out in the document filed with the OEB, this variance represents $23,203.

Account Grouping: 3800-Administrative & General Expenses

The total variance between the 2006 EDR and the Actual 2006 Expenses is a decrease of $118,108.

Acct # & Name	2006 EDR	2006 Actual	Variance
#5665-Miscellaneous General Expenses	$194,927	$69,717	-$125,209
#5680-Electrical Safety Authority Fees	$0	$7,626	$7,626

Explanation:

Account 5665 - Miscellaneous General Expenses shows a decrease of $125,209 because the 2006 EDR included an expense amount of $152,520 for low voltage/wheeling adjustment, which is not reflected in this account for 2006 actual or later years. In 2006 and subsequent years the actual low voltage charges are posted to account 4750-Charges-LV.

In 2006 the shareholder reviewed the remuneration of the directors and adjusted it accordingly to inflation and based on a survey of other like size utilities. The directors had not had a remuneration adjustment since the amalgamation in January 1999.

Account 5680 – Electrical Safety Authority had a variance of $7,626 as this was a new charge from the Electrical Safety Authority in 2006.

Account Grouping: 3850-Amortization Expense

The total variance between the 2006 EDR and the Actual 2006 Expenses is a decrease of $21,580.

Acct # & Name	2006 EDR	2006 Actual	Variance
#5705-Amortization Expense	$510,349	$488,770	-$21,580

Explanation:

The board approved data [2002 to 2004] was generated in the EDR filing based on very dated data. The difference between 2006 EDR and 2006 Actual is partly the result of fully depreciated assets in 2005 thus reducing the amortization expense in 2006. The increase in amortization of contributed capital is also reduced the expense by $11,554.

Account Grouping: 3950-Taxes Other Than Income Taxes

Acct # & Name	2006 EDR	2006 Actual	Variance
#6105 – Taxes Other Than Income Taxes	$30,832	$52,866	$22,034

Explanation:

Account 6105-Taxes Other Than Income Taxes shows an increase of $22,034, because at the end of December 2006 the auditors did a year end entry to PILS provision and to clear up prior years debits.

2006 Actual vs. 2007 Actual

Total OM&A Expenses increased in 2007 by $70,053 over 2006 balances. Those expenses whose materiality level exceeded 1% in 2007 vs. the 2006 Actual Expenses are set out below along with an analysis of Amortization, Interest and Income Taxes where the variances are greater than 1%.

Account Grouping: 3500-Distribution Expenses – Operations

The total variance between the 2006 Actual and the Actual 2007 Expenses is an increase of $38,185 of which $37,951 is explained below.

Acct # & Name	2006 Actual	2007 Actual	Variance
#5005-Operation Supervision & Engineering	$70,850	$97,211	$26,361
#5065-Meter Expenses	$54,097	$70,404	$16,307

Explanation:

Account 5005 – Operation Supervision and Engineering - increase is due to increased time transferred into account 5005 as a result of additional time spent to meet ESA requirements. The increase is also due to normal wage increases and related overheads. As well the Applicant needed to contract assistance from an outside engineering firm to comply with these new requirements.

Account 5065 – Meter Expenses increased by $16,307 due to meters that had to be changed to meet Measurement Canada guidelines. The Applicant had deferred resealing meters because of the impending smart meter implementation.

Account Grouping: 3550-Distribution Expenses – Maintenance

The total variance between the 2006 Actual and the Actual 2007 Expenses is an increase of $5,629 of which is not above the 1% variance, however account 5114 is above the 1% variance and therefore explained below.

Acct # & Name	2006 Actual	2007 Actual	Variance
#5114-Maintenance of Distribution Station	-$811	$52,555	$53,366

Explanation:

Account 5114 – Maintenance of Distribution Station - The majority of this account was for two particular jobs, 07-030 and 07-070. Job #070-030 completed extensive station maintenance on Sub Station 2 in Elora, amounting to $25,704. Job #07-070 completed maintenance on Sub Station 1 in Fergus, amounting to $16,530. The remaining of the variance was on inspections of Centre Wellington Hydro Substations, including oil samples and analysis for all the remaining transformers stations.

With account 5114 seeing a significant increase in labour hours, accounts such as 5130 – Maintenance of Overhead Services, 5125 Maintenance of Overhead Conductors and Devices and 5120 Maintenance of Poles Towers and Fixtures all saw decreases in labour, making the above variance strictly a reallocation of labour hours.

Account Grouping: 3650-Billing and Collecting

The total variance between the 2006 EDR and the Actual 2006 Expenses is a decrease of $14,194 of which $13,706 is explained below.

Acct # & Name	2006 Actual	2007 Actual	Variance
#5315-Customer Billing	$219,626	$213,142	-$6,484
#5320-Collecting	$68,951	$57,624	-$11,687
#5335-Bad Debt Expense	$81	$4,546	$4,465

Explanation:

Account 5315 – Customer Billing saw a decrease of $6,484 due to cost savings that are being attributed to the use of the new ASP provider.

Account 5320 – Collecting saw a decrease of $11,687 due to a temporary reduction in staffing costs due to a maternity leave and hiring a contract person to cover that position.

Account 5335 – Bad Debt Expense saw an increase of $4,465 due to accounts identified as uncollectable being written off. Action was taken to collect these accounts, but all attempts were unsuccessful.

Account Grouping: 3700-Community Relations

The total variance between the 2006 EDR and the Actual 2006 Expenses is a decrease of $8,413, of which $8,703 is explained below.

Acct # & Name	2006 Actual	2007 Actual	Variance
#5410-Community Relations Sundry	$16,687	$8,061	-$8,626
$5415-Energy Conservation	$23,203	$28,645	$5,442
#5425-Miscellaneous Customer Service and Information Expense	$9,718	$4,199	-$5,519

Explanation:

Account 5410 – Community Relations – Sundry decreased by $8,626 because the Applicant had budgeted fewer dollars in this area, to reflect actual spending.

Account 5415 – Energy Conservation showed an increase in spending of $5,442 because the Applicant spent the balance of the third tranche on the approved CDM plan as per OEB Guidelines.

Account 5425 – Miscellaneous Customer Service and Informational Expenses – also decreased by $5,519 because again fewer dollars were budgeted in this area. The Applicant had hosted several public information sessions in the previous year that were poorly attended by the public, it was decided that alternative methods would be explored moving forward. The Applicant is looking at a co-operative model of working together with several other LDC's to deliver specialized workshops for each individual community.

Account Grouping: 3800-Administrative and General Expenses

The total variance between the 2006 Actual Expenses and the Actual 2007 Expenses is an increase $47,733 of which $39,462 is explained.

Acct # & Name	2006 Actual	2007 Actual	Variance
#5610-Management Salaries and Expenses	$222,403	$243,537	$21,135
#5615-General Administration Salaries and Expenses	$129,478	$141,524	$12,046
#5630-Outside Services Employed	$52,315	$34,578	-$17,738
#5640-Injuries and Damages	$14,502	$31,761	$17,259
#5645-Employee Pensions and Benefits	-$482	$8,394	$8,876
#5655-Regulatory Expenses	$24,266.33	$27,016	$2,749
#5675-Maintenance of General Plan	$12,567	$16,341	$3,774

Explanation:

Account 5610-Management Salaries and Expenses increased by $21,135. The increase in this account is mainly due three factors; they are (1) in 2006 salaries were offset by an insurance disability claim of $7,992 where the utility was reimbursed for salaries paid out while the person was on medical leave (2) an increase in travel expenses of $4,734 and (3) an increase in salaries of $8,409 to reflect annual increase and adjustments.

Account 5615-General Administrative Salaries and Expenses increased by $12,046. The increase is mainly due to two factors; (1) hiring of a summer student to assist with summer vacations and to transfer files to storage costing $3,781 and (2) normal increases in salaries and the payment for overtime to office staff in appreciation for the extra time and commitment that was involved in ensuring that the $6,230 upgrade of the billing system went smoothly.

Account 5630-Outside Services Employed decreased by $17,738. The need for Outside Consultants shifts from year-to-year depending on what is happening in the industry and the Applicant's requirements. In 2006 the Applicant had additional consulting fees for (1) payment to Hydro One Networks of $10,500 for the completion of the load data for the cost allocation report, (2) payment to an outside consultant to determine how the Applicant could have on-going savings in telephone charges – cost $1,938 and (3) payment to a consultant in the setting up of a co-operative billing ASP provider to find future savings on computer system and IT costs of $9,421. In 2007 we used outside consultants to assist with the rate application.

Account 5640-Injuries and Damages increased by $17,259. The increase is largely due to contracting with MEARIE to provide "Business Credit Insurance" to mitigate losses involving General Service customers at a cost of $13,268 and an increase in liability insurance premiums of $3,761.

Account 5645-Employee Pensions and Benefits increased by $8,876. This increase is due to the fact that in 2006 there was a large credit adjustment to the "Employee Future Benefits" as calculated by the actuarial firm within the CICA guidelines.

Account 5655-Regulatory Expenses increased by $2,749. This increase was due to the charge by the OEB for cost awards. Currently the Applicant doesn't record any costs related to completing regulatory requirements by internal staff or outside services to this account. This account reflects only the OEB costs and the ESA fees.

Account 5675 – Maintenance of General Plant – increased by $3,774. Most of this $2,100, was due to an increase in janitorial costs. The Applicants original janitorial services closed their business; leaving the Applicant to find a new company. As well, $1,800 was due to an increase in spending maintenance and repairs of computer hardware.

Account Grouping: 3850-Amortization Expense

The total variance between the 2006 Actual and the Actual 2007 Expenses is an increase of $22,543.

Acct # & Name	2006 Actual	2007 Actual	Variance
#5705-Amortization Expense	$488,770	$511,313	$22,543

Explanation:

Account 5705-Amortization expense increase in 2007 by $22,543 as a result of purchases of capital assets in 2006 and 2007. The Applicant uses the half year rule for all capital asset purchases in the current year.

Account Grouping: 3950-Taxes Other Than Income Taxes

Acct # & Name	2006 Actual	2007 Actual	Variance
#6105 – Taxes Other Than Income Taxes	$52,866	$31,436	-$21,430

Explanation:

Account 6105-Taxes Other Than Income Taxes decreased in 2007 by $21,430 due to a one time entry of $22,000 made by the auditors at the end of December 2006 for PILS provision and to clear up prior years debits.

2007 Actual vs. 2008 Bridge

Total OM&A Expenses will increase in 2008 by $267,086 over 2007 balances. Those expenses whose materiality level exceeded 1% in 2008 vs. the 2007 Actual Expenses are set out below along with an analysis of Amortization, Interest and Income Taxes where the variances are greater than 1%.

Account Grouping: 3500-Distribution Expenses – Operations

The total variance between the 2007 Actual Expenses and the Bridge 2008 Expenses is an increase $28,393, of which $37,250 is described below.

Acct # & Name	2007 Actual	2008 Bridge	Variance
#5055-Underground Distribution Transformers-Operations	$577	$7,200	$6,623
#5065-Meter Expense	$70,404	$87,400	$16,996
#5085-Miscellaneous Distribution Expense	$29,869	$43,500	$13,631

Explanation:

Account 5055-Underground Distribution Transformers-Operations increased spending of $6,623 due to inspections of all padmount transformers. This work was undertaken on all padmount transformers in the system, with the view to implementing a three year inspection cycle.

Account 5065 – Meter Expense increased by $16,996 due to meter reverification costs.

Account 5085-Miscellaneous Distribution Expense increased by $13,631 due to increased cost related to outsourcing of assistance and training of staff related to taking over more of the mapping upgrade functions, and the increased hours of part-time staff to assist with recording and reporting functions related to the new ERA Standards.

Account Grouping: 3550-Distribution Expenses - Maintenance

The total variance between the 2007 Actual Expenses and the Bridge 2008 Expenses is an increase of $43,487. Those accounts that exceed the 1% variance total $44,941, a summary of which is included below.

Acct # & Name	2007 Actual	2008 Bridge	Variance
#5120-Maintenance of Poles, Towers and Fixtures	$7,872	$30,000	$22,128
#5125-Maintenance of Overhead Conductors and Devices	$28,987	$51,800	$22,813

Explanation:

Account 5120 – Maintenance of Poles, Towers and Fixtures - In conjunction with conductor replacement some individual poles will have to be replaced.

Account 5125 – Maintenance of Overhead Conductors and Devices - In a continuing effort to make improvements in reducing line losses the Applicant proposes to specifically target the replacement of all small primary conductors (i.e. #6 copper) in the distribution system. This work will also include the replacement of insulators, clamps, grounding and connections.

Account Grouping: 3650-Billing and Collecting

The total variance between the 2006 EDR and the Actual 2006 Expenses is an increase of $8,699 of which is explained below.

Acct # & Name	2007 Actual	2008 Bridge	Variance
#5320-Collecting	$57,264	$73,700	$16,436

Explanation:

Account 5320 – Collecting increased by $16,436. This increase is due to the return of a full-time cashier from maternity leave. As well we had an overlap of duties in order to provide re-training of the cashier due to changes in the CIS system while she was on maternity leave. The Applicant also elected to retain the experienced services of the contract person until the end of 2008. The reason for this was to provide coverage for summer vacations and to cover for staff assisting with the 2009 rebasing application and phase one of the upgrade of the financial system.

Account Grouping: 3700-Community Relations

The total variance between the 2007 Actual Expenses and the Bridge 2008 Expenses is an increase of $13,722, which is not over the 1%, however within the account there are sub accounts that exceeds the 1% variance.

Acct # & Name	2007 Actual	2008 Bridge	Variance
#5410-Community Relations	$8,061	$42,300	$34,239
#5415-Energy Conservation	$28,645	$4,300	-$24,345

Explanation:

Account 5410-Community relations – The Applicant is planning a production of a short video clip explaining time of use rates. There will also be a short segment on Safety and Conservation as well as emergency preparedness in the home. This will air on the local cable channel that is specific to customers in our service area. The estimated cost of the video clip is $38,500.

Account 5415-Energy Conservation – Our funding requirements for energy conservation has been reduced because it is our understanding that the OPA has been charged with implementing an array of new conservation programs.

In 2007 the Applicant completed the approved spending on CDM programs which were recorded in this account. The current budget of $4,300 is for smart meter presentations, presented by our current staff and will include handouts all for our customers.

Account Grouping: 3800-Administrative and General Expenses

The total variance between the 2007 Actual Expenses and the Bridge 2008 Expenses is an increase of $103,049. Those accounts that exceed the 1% variance total $99,420 a summary of which is included below.

Acct # & Name	2007 Actual	2008 Bridge	Variance
#5610-Management Salaries and Expenses	$243,537	$257,000	$13,463
#5615-General Administrative Salaries and Expenses	$141,524	$188,000	$46,476
#5630-Outside Services Employed	$34,578	$65,600	$31,022
#5665-Miscellaneous General Expenses	$73,041	$81,500	$8,459

Explanation:

Account 5610-Management Salaries and Expenses shows an increase of $13,463 to cover higher travel expenses related to meetings, seminars and conferences and salaries.

Account 5615-General Administrative Salaries and Expenses shows an increase of $46,476 because the Applicant hired a full-time contract employee in April 2008 to assist with the 2009 Rate Application and to cover for a leave of absence because a full-time employee has elected to return to school for 10 months to complete her 4th and 5th year of the CGA program. This variance also reflects the cost of another contract employee to assist with the summer work load in both Billing and Collecting and Administrative and General areas while people are on vacation and to backup staff while starting the implementation of the new financial system. This account also includes an additional $1,200 for training related to issues around smart meters and the financial system.

Account 5630-Outside Services shows an increase of $31,022. This increase is largely due to the hiring of an outside consultant ($15,600) to assist in team building exercise, conflict resolution and to establish and maintain a high level of respect amongst the employees. This will help to identify staff stressors, development of coping skills within the work place as well as effectively keep the lines of communication open. This will not only assist the inside staff but

will assist the outside staff maintain a safe work environment by underscoring the importance of mutual respect understanding and work processes. The balance is due to increased audit fees, hiring of a consultant to assist with boundary issues ($5,000) and consulting fees related to 3rd Generation IRM.

Account 5665-Miscelleanous General Expenses show an increase of $8,459 because of the increase in Corporate Membership dues of $2,348; Shareholder Meeting Expenses of $3,400 and other miscellaneous expenses of $2,711 is due to conference and travel expenses, telephone, stationary and director's remuneration.

Account Grouping: 3850-Amortization Expense

The total variance between the 2007 Actual and the 2008 Expenses is an increase of $82,872.

Acct # & Name	2007 Actual	2008 Bridge	Variance
#5705-Amortization Expense	$511,313	$594,185	$82,872

Explanation:

Account 5705-Amortization Expense increased by $82,872 as a result of purchases of capital assets in 2007 and 2008. The Applicant uses the half year rule for all capital asset purchases in the current year.

Account Grouping: 3950-Taxes Other Than Income Taxes

Acct # & Name	2007 Actual	2008 Bridge	Variance
#6105 – Taxes Other Than Income Taxes	$31,436	$33,000	$1,564

Explanation:

Account 6105-Taxes Other Than Income Taxes increased by $1,564 due to tax rate adjustments put in place by the Township of Centre Wellington to cover municipal, county and school expenditures.

2008 Bridge to 2009 Test Year

Total OM&A Expenses will increase in 2009 by $72,399 over 2008 balances. Those expenses whose materiality level exceeded 1% in 2009 vs. the 2008 Bridge Year Expenses are set out below along with an analysis of Amortization, Interest and Income Taxes where the variances are greater than 1%.

Account Grouping: 3500-Distribution Expenses – Operations

The total variance between the 2008 Bridge and the 2009 Expenses is a decrease of $20,000 of which $24,900 is explained below.

Acct # & Name	2009	2008	Variance
#5065-Meter Expense	$62,500	$87,400	-$24,900

Explanation:

Account 5065-Meter Expenses are lower in 2009 by $24,900 because the Applicant anticipates installing Smart Meters in 2009. In 2008 the Applicant allocated additional funds in this account for labour and overheads for the existing staff and a contract firm to change out some of the unsafe meter bases and meters that are located inside dwellings, the balance of the meter base changes and inside meter changes will be done in 2009. Also charges, to this account, is the cost of changing out meter that do not qualify for the smart meter replacement plan as out lined in the regulations, but have gone beyond Measurement Canada's seal date.

Account Grouping: 3550-Distribution Expenses – Maintenance

The total variance between the 2008 Bridge and the 2009 Test Year expenses is a decrease of $3,600. As all amounts are under the materiality threshold no further explanation is given at this time.

Account Grouping: 3650-Billing and Collecting

The total variance between the 2008 Bridge and the 2009 Expenses is an increase of $9,100 of which $21,200 is explained below.

Acct # & Name	2009	2008	Variance
#5315-Customer Billing	$231,000	$209,800	$21,200

Explanation:

Account 5315-Customer Billing has increased by $21,200. This increase is largely due to the anticipated increase in postage cost ($5,800) and computer expenses ($7,900). The balance of the increase ($7,500) is due to minor increase and decreases in expenses posted to this account.

Account Grouping: 3700-Community Relations

The total variance between the 2008 Bridge expenses and the 2009 Test Year expenses is a decrease of $20,900, which is not over the 1% variance threshold.

Acct # & Name	2008 Bridge	2009	Variance
#5410-Community Relations	$42,300	$3,800	-$38,500
#5415-Energy Conservation	$4,300	$9,600	$5,300
#5420-Community Safety Program	$0	$3,500	$3,500
#5425-Miscellaneous Customer Service and Informational Expenses	$7,900	$16,300	$8,400

Explanation:

Account 5410-Community Relations-Sundry shows a decrease in expenditures of $38,500 because the Applicant will have already paid for the production of a short video clip explaining time of use rates.

Account 5415-Energy Conservation shows an increase of $5,300 because of an energy conservation plan that will specifically target low income families to assist them in reducing their consumption.

Account 5420-Community Safety Program shows an increase of $3,500 to pay for safety and energy conservation programs being offered to public school children within the surrounding area. This program is offered to local schools once every three years

Account 5425-Miscelleanous Customer Service and Information expenses shows an increase of $8,400. This additional expense is to give away "energy crunch kits" to customers at community functions and various information sessions, in the hope of increasing public awareness and attendance at the different functions. These functions are outside of the programs being offered by the OPA.

Account Grouping: 3800-Administrative and General Expenses

The total variance between the 2008 Bridge Year expenses and the 2009 Test Year expenses is $47,100.

Acct # & Name	2008 Bridge	2009	Variance
#5610-Management Salaries & Expenses	$257,000	$283,000	$6,800
#5615-General Admin Salaries & Expenses	$188,000	$191,400	$3,400
#5620-Office Supplies and Expenses	$42,700	$49,200	$6,500
#5630-Outside Services Employed	$65,600	$50,000	-$15,600
#5635-Property Insurance	$11,000	$12,000	$1,000
#5640-Injuries and Damages	$29,000	$33,200	$4,200
#5655-Regulatory Expenses	$25,800	$65,200	$39,400
#5680-Electricial Safety Authority Fees	$7,800	$9,000	$1,200

Explanation:

Account 5610-Management Salaries and Expenses increased by $6,800. This is made up of $3,000 for increase cost in travel, conferences, seminars and miscellaneous expenses in order to keep abreast with changes in the industry and $3,800 for increases in salaries and payroll burdens.

Account 5615-General Administrative Salaries and Expenses increased by $3,400. This is made up of $600 for travel, conferences, seminars and miscellaneous expenses and $2,800 for increases in salaries and payroll burdens.

Account 5620–Office Supplies and Expenses increased by $6,500 to cover the increase in travel expenses, bank charges, telephone charges, stationery and printing, courier, etc.

Account 5630–Outside services employed decreased by $15,600 mainly because the 2008 expenditures included a one-time cost for a consultant to conduct a team building and conflict resolution workshop for all staff.

Account 5635-Property Insurance increased by $1,000 to cover anticipated increases in insurance premiums based on pass history.

Account 5640-Injuries and Damages increased by $4,200 to cover anticipated increases in liability insurance premiums and increase cost of the business credit insurance premiums.

Account 5655 – Regulatory Expenses increased by $39,400 in order to cover the cost of completing the 2009 rebasing application. The rebasing expenses are being posted to a prepaid expense in 2008 and are being written off over a three year bases. The cost includes incremental labour costs, outside consultant's fees, legal fees, Intervener costs, cost of the OEB hearing, printing and courier costs. This account does not include non-incremental costs.
Account 5680 – Electrical Safety Authority increased by $1,200 to cover anticipated increases based on past history of actual expenditures.

Account Grouping: 3850-Amortization Expense

Acct # & Name	2008 Bridge	2009 Test	Variance
#5705-Amortization Expense	$594,185	$638,184	$43,999

Explanation:

Account 5705-Amortization Expense increased by $43,999 as a result of purchases of capital assets in 2008 and 2009. The Applicant uses the half year rule for all capital asset purchases in the current year.

Account Grouping: 3950-Taxes Other Than Income Taxes

Acct # & Name	2008 Bridge	2009 Test	Variance
#6105 – Taxes Other Than Income Taxes	$33,000	$35,000	$2,000

Explanation:

Account 6105-Taxes Other Than Income Taxes increased by $2,000 due to anticipated tax rate adjustments to be put in place by the Township of Centre Wellington to cover municipal, county and school expenditures.

Shared Services

The Applicant does not share services with any affiliates.

Service Agreement(s)

Not Applicable

Corporate Cost Allocation

Not Applicable

Purchase of Services

Name of Company Transacting with the Applicant	Summary of the nature of the activity transacted	Summary of tendering process/summary of cost approach	2007 Actual	2008 Bridge	2009 Test
1640200 Ontario Limited	Office Cleaning	Contract	$ 2,438	$ 5,520	$ 5,600
Acumen Engineered Solutions International	Engineering	Cost Approach	$ 6,683	$ 5,000	$ 5,000
Allan Fyfe Equipment Ltd	Rolling Stock	Cost Approach	$ 2,224	$ 2,500	$ 2,500
Atria Networks	Scada system, internet	Contract	$ 6,704	$ 6,350	$ 6,350
Basics Office Products	Stationary	Contract	$ 6,447	$ -	$ -
Burlington Business Forms	Printing of bills	Contract	$ 2,443	$ 1,250	$ 1,250
Bellamy Farm Services	Groundskeeping	Cost Approach	$ 3,174	$ 3,200	$ 3,200
Boucher & Jones Inc	Fuel	Contract	$ 12,352	$ 15,000	$ 21,000
Bell Mobility	Cell Phones	Contract	$ 3,062	$ 3,000	$ 3,150
Black, Shoemaker, Robinson & Donaldson	Legal	Cost Approach	$ 2,481	$ 2,000	$ 2,000
Bel Volt Sales Ltd	Poles, Towers, Fixtures, Transformers	Cost Approach	$ 9,044	$ 75,600	$ 102,000
Carte International Inc.	Transformers	Cost Approach	$ 30,578	$ -	$ 102,000
Cue Engineering Inc.	Rolling Stock	Cost Approach	$ 2,433	$ 2,500	$ 2,700
DG Technologies Ltd	Meters	Cost Approach	$ 2,849	$ 5,000	$ 5,000
Domm Construction Limited	Building repair	Cost Approach	$ 2,560	$ 1,000	$ 1,000
Drexler Construction Ltd	Backhoe for U/G Conduit	Cost Approach	$ 15,891	$ -	$ -
Electricity Distributors Association	EDA Membership	Contract	$ 13,408	$ 13,500	$ 13,500
Eloquip Ltd.	Rolling Stock, assets	Cost Approach	$ 24,985	$ -	$ -
Elster Metering	Meters	Cost Approach	$ 8,162	$ 15,000	$ 15,000
Electrical Safety Authority	Electrical Safety	Contract	$ 3,697	$ 3,700	$ 3,700
Euler Hermes Canada	Insurance-Business Credit Risk	Contract	$ 13,268	$ 13,300	$ 13,300
Fergus-Elora News Express	Advertising	Contract	$ 2,037	$ 2,000	$ 2,000
Foster Sewer Services	Vacuvation, Holes & Poles	Cost Approach	$ 6,871	$ 7,000	$ 7,000
Green-Port Environmental	PCB work, Oil Disposal	Cost Approach	$ 4,579	$ 2,000	$ 2,000
Guelph Hydro Electric System	Mapping upgrades	Cost Approach	$ 16,982	$ 23,000	$ 23,000
Guelph Utility Pole Co	Poles	Cost Approach	$ 20,920	$ 22,000	$ 24,000
Harris Computer Systems	Computer Software	Contract	$ 60,137	$ 104,000	$ 90,000

HD Utilities Supply	Distribution line materials	Cost Approach	$ 38,660	$ 40,000	$ 40,000
Howes & Reeves Limited	truck	Cost Approach	$ 38,892	$ -	$ -
Information Network Systems Inc.	Billing equipment	Cost Approach	$ 17,570	$ 2,500	$ 2,500
Itron Canada Inc.	Meter Reading equipment	Cost Approach	$ 7,642	$ 7,600	$ 7,600
KPMG	Audit and Tax Returns	Cost Approach	$ 26,129	$ 27,000	$ 27,000
Klaas Swaving Ltd.	Transformer painting	Cost Approach	$ 2,958	$ 1,000	$ 1,000
Lakeport Power Ltd.	Transformers	Cost Approach	$ 60,737	$ 72,000	$ 102,000
Minister of Finance - Min of Transportation	Rolling Stock	Cost Approach	$ 2,432	$ 2,500	$ 2,500
MEARIE Management Inc.	Insurance-Business Credit Risk	Contract	$ 13,975	$ 15,000	$ 15,000
MRC Systems Inc.	Radios	Cost Approach	$ 2,235	$ 2,500	$ 2,500
Norfolk Power	Mtce of Distribution Station Equip, Contract	Cost Approach	$ 2,110	$ -	$ 2,000
Noramco Wire & Cable	Wire	Cost Approach	$ 56,568	$ 57,000	$ 58,000
National Paper Goods	envelopes	Cost Approach	$ 4,239	$ 4,500	$ 4,500
Ontario Energy Board	Regulatory Expense	Cost Approach	$ 19,067	$ 20,000	$ 20,000
Olameter Inc.	Meters and Meter Reading	Cost Approach	$ 11,850	$ 12,000	$ 13,000
OSTIC Insurance Brokers	Insurance	Cost Approach	$ 21,064	$ 22,000	$ 23,000
Primus Canada	Phone service	Cost Approach	$ 7,661	$ 7,700	$ 7,800
Protector Security & Locksmith Corp.	Security	Cost Approach	$ 5,181	$ 4,000	$ 4,000
Pryde Truck Service Ltd	Rolling Stock	Cost Approach	$ 5,947	$ 6,000	$ 6,500
Rodan Energy & Metering Solutions	Metering Expense	Cost Approach	$ 6,493	$ 6,500	$ 6,600
Rogers Wireless Inc.	Wireless Services	Cost Approach	$ 3,596	$ 3,600	$ 3,700
Rowe Electric	Building repairs & mtce, meter base repair	Cost Approach	$ 3,739	$ 4,000	$ 4,000
The SPI Group	EBT Hub Services	Contract	$ 7,280	$ 7,300	$ 7,300
State Chemical Ltd.	Janitorial Expenses	Cost Approach	$ 2,951	$ 3,000	$ 3,000
Triton Engineering Serv.	Engineering Services	Cost Approach	$ 6,361	$ 2,000	$ 2,000
The ITM Group	Computer Technology	Contract	$ 57,569	$ 58,000	$ 59,000
Utility Collaborative Services	Hosting Services	Cost Approach	$ 68,463	$ 69,000	$ 69,000
Union Gas Limited	Gas	Cost Approach	$ 5,457	$ 7,000	$ 8,000
Util-Assist	Smart Meter Consulting	Contract	$ 18,692	$ 19,000	$ 20,000
Utilismart Corporation	Settlement Services	RFP	$ 62,964	$ 64,000	$ 65,000
Wajax Industries Limited	Rolling Stock	Cost Approach	$ 17,135	$ 15,000	$ 15,000
Wellington Door & General Contractor	Building Repairs & Mtce	Cost Approach	$ 3,780	$ 4,000	$ 4,200
Waterloo North Hydro	Distribution Expenses	Cost Approach	$ 26,882	$ 27,000	$ 27,000

Westburne Electrical Inc.	Distribution Expenses	Cost Approach	$ 8,257	$ 9,000	$ 10,000
Total			$ 930,945	$ 935,120	$ 1,098,950

The Applicant has provided a sample of expenditures for the purchase of products and services from vendors as required by the Filing Requirements. Although the list is not all inclusive, vendors with expenditures exceeding $2,000 in any of the three years have been included.

Employee Description

	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Number of employees (Full-time equivalents (FTE's):					
Non-Unionized	10	11	10.5	10.5	10.5
Unionized	4	4	4	4	4
Number of employees (Part-time equivalents (PTE's):					
Non-Unionized	0	0.5	0.75	0	0
Unionized	0	0	0	0	0

Compensation (Total Salary and Wages ($)):

	2006 Board Approved	Avg	2006 Actual	Avg	2007 Actual	Avg	2008 Bridge	Avg	2009 Test	Avg
Non-Unionized (FTE's)	$ 532,980	$ 53,298	$ 578,464	$ 52,588	$ 623,809	$ 59,410	$ 643,469	$ 61,283	$ 644,745	$ 61,404
Unionized	$ 238,920	$ 59,730	$ 286,698	$ 71,674	$ 283,785	$ 70,946	$ 284,547	$ 71,137	$ 292,772	$ 73,193

Compensation (Total Benefits ($)):

	2006 Board Approved	Avg	2006 Actual	Avg	2007 Actual	Avg	2008 Bridge	Avg	2009 Test	Avg
Non-Unionized (FTE's)	$ 78,226	$ 7,823	$ 79,747	$ 7,250	$ 84,242	$ 8,023	$ 95,000	$ 9,048	$ 93,000	$ 8,857
Unionized	$ 66,112	$ 16,528	$ 78,643	$ 19,661	$ 80,430	$ 20,108	$ 81,800	$ 20,450	$ 84,000	$ 21,000

	2006 Actual	2007 Actual	2008 Bridge	2009 Test
OM & A Costs in Labour	$ 815,954	$ 855,547	$ 847,430	$ 815,100

Centre Wellington Hydro's part time employees, other than summer students, are all permanent part time, and for this reason, are included as FTE's.

Loss Adjustment Factor Calculation

		2003	2004	2005	2006	2007		
A	Purchased kWh's	154,812,595.10	160,096,079.00	160,363,706.00	159,479,086.37	162,041,784.23		
B	"Wholesale" kWh (IESO) **Qty at the Meter**	151,086,095	156,211,548	155,716,390	154,774,514	157,382,043	**5 Yr Avg**	**3 Yr Avg**
C	Supply Facility Loss Factor [(A-B)]	1.0247	1.0249	1.0298	1.0304	1.0296	1.0279	1.02995

		2003	2004	2005	2006	2007		
D	"Wholesale" kWh (IESO) **Qty at the Meter**	151,086,095	156,211,548	155,716,390	154,774,514	157,382,043		
E	Wholesale kWh for Large Use customer(s) (IESO)	-	-	-	-	-		
F	Net "Wholesale" kWh (D)-(E)	151,086,095	156,211,548	155,716,390	154,774,514	157,382,043		
G	Retail kWh (Distributor) **Qty at the Meter**	142,455,155	141,146,934	149,056,811	150,448,842	151,678,570		
H	Retail kWh for Large Use Customer(s) (1% loss)	-	-	-	-	-		
I	Net "Retail" kWh (G)-(H)	142,455,155	141,146,934	149,056,811	150,448,842	151,678,570	**5 Yr Avg**	**3 Yr Avg**
J	Distribution Loss Factor [(F)/(I)]	1.0606	1.1067	1.0447	1.0288	1.0376	1.0557	1.0370

Total Utility Loss Adjustment Factor	**LAF**
Supply Facility Loss Factor	1.0299
Distribution Loss Factor	1.0370
Total Loss Factor	
Secondary Metered Customer	
Total Loss Factor - Secondary Metered Customer < 5,000kW	1.0681
Total Loss Factor - Secondary Metered Customer > 5,000kW	n/a
Primary Metered Customer	
Total Loss Factor - Primary Metered Customer < 5,000kW	1.0574
Total Loss Factor - Primary Metered Customer > 5,000kW	n/a

The Applicant is proposing to decrease the distribution loss factor from 1.0425 to 1.0370.

A Supply Facility Loss Factor (SFLF) of 1.0045 was used in the 2006 EDR. Centre Wellington Hydro has recalculated the SFLF to be 1.0299 for this rate application as seen in the above table. We have used a three year average for both the Distribution Loss Factor and SFLF instead of the traditional five year average, due to a higher than normal distribution loss factor in the earlier years.

The applicant is seeking approval for a total loss Factor of 1.0681 which is based on a three year average of both the Distribution Loss Factor and the Supply Facilities Loss Factor. The three year average has been chosen over the typical five year average to remove unusually high distribution loss factor amounts for the 2003 and 2004 years.

Details of Total Losses

"Wholesale" kWh					
	2003	2004	2005	2006	2007
January	14,690,749.96	14,994,481.91	15,004,916.20	14,334,961.98	14,468,145.06
February	13,078,855.44	13,571,202.21	10,683,778.10	13,268,773.63	13,637,367.64
March	13,281,269.34	14,015,407.53	13,751,692.30	14,078,154.39	13,865,203.44
April	12,002,619.66	12,452,694.76	12,080,799.00	12,028,054.82	12,415,889.94
May	11,451,520.05	11,829,313.06	11,580,570.00	12,161,630.22	11,822,300.07
June	11,949,797.22	12,257,969.11	13,384,879.60	12,565,193.68	12,844,519.96
July	12,639,674.23	12,616,083.98	13,464,680.10	13,325,471.52	12,488,979.92
August	10,848,024.81	12,406,096.37	13,258,327.80	12,293,785.08	12,547,847.02
September	11,909,991.59	12,325,476.99	11,929,412.50	11,686,449.62	12,160,112.00
October	12,756,563.21	12,636,799.51	12,942,834.20	12,619,019.69	12,819,723.63
November	12,832,718.21	13,061,212.55	13,449,015.60	13,140,857.81	14,436,756.12
December	13,644,311.26	14,044,811.90	14,185,484.60	13,272,161.39	13,875,198.49
Totals	151,086,094.98	156,211,549.88	155,716,390.00	154,774,513.83	157,382,043.29

"Retail" kWh	2003	2004	2005	2006	2007
Residential	43,857,044	42,857,515	45,720,301	44,420,019	44,564,315
GS<50	22,491,216	19,775,487	22,056,965	22,033,116	21,715,633
USL	-	-	-	-	314,675
GS>50	23,499,219	24,612,727	26,536,255	21,746,645	20,037,363
Int >50	4,019,840	4,197,746	5,688,191	13,809,887	15,402,683
Int >1000	23,416,934	24,554,515	25,226,594	28,241,983	27,828,686
Intermediate	24,031,646	23,979,089	22,650,013	19,020,063	20,647,752
Street Lights	1,091,080	1,122,195	1,131,022	1,130,201	1,121,887
Sentinel Lights	48,176	47,660	47,470	46,928	45,576
Totals	**142,455,155**	**141,146,934**	**149,056,811**	**150,448,842**	**151,678,570**

Variance and Materiality Analysis on Distribution Losses

The Applicant submits that the method of determining it's proposed loss adjustment factor is consistent with the methodology set out in section 10-5 of the 2006 EDR Handbook.

In order to help reduce line losses at Centre Wellington Hydro several key items are considered.

The main item is tree trimming. The Applicant follows an aggressive two year tree trimming schedule in order to eliminate losses due to contact with trees and to reduce outages caused by tree branches touching or falling on conductors.

The operations department uses new design standards for capital and maintenance works in order to keep line losses at a minimum by using proper wire sizing.

Transformers with low losses are purchased to ensure optimal performance of the core of the transformer. Proper sizing of transformers is considered when installing a new or replacement transformer to ensure line losses are kept to a minimum.

The Applicants staff regularly monitors all feeders to identify imbalances with a view to taking corrective action. On occasion a system improvement study and a coordination study has been contracted out to see if improvements other than load imbalance can be identified.

Reducing lines losses is a goal at Centre Wellington Hydro both from the financial implications and to make for a more efficient, safe and reliable distribution of power to our customers.

Retail Transmission Adjustment Calculations

The Applicant has reviewed its Retail Transmission Rates – both Network and Connection and recalculated those rates to reflect revenues required to equal the cost of Retail Transmission Rates from Hydro One. The large credit balance in the connection deferral variance account is the cause of the request to dispose of the balances in these two accounts in conjunction with this rate application. The calculations for disposal of these accounts are included in Exhibit 5.

The following table provides the calculations to arrive at rates the applicant feels will more closely reflect the Hydro One costs of these services.

The following table provides the calculations used for the revised rates:

Transmission Network Rates

2009 **Not including RSVA Adjt**

Class	NW – 4714 Cost	%of total kWh (or kW) per class * balance in 4714	New NW Rate	Proof	2009 - kWh	2009 - kW	NW - 4066 Revenue	% of total kWh per class
Residential		261,039	**0.0055**	$ 261,054	47,172,831		$ (183,974)	31.85%
GS<50		113,419	**0.0050**	$ 113,416	22,838,459		$ (79,935)	13.84%
GS>50		338,522	**2.0328**	$ 338,522		166,526	$ (238,582)	41.30%
Street Lights		4,701	**1.5331**	$ 4,701		3,066	$ (3,313)	0.57%
Sentinel Lights		188	**1.5409**	$ 188		122	$ (132)	0.02%
Unmetered Scattered Load		2,083	**0.0050**	$ 2,082	419,344		$ (1,468)	0.25%
Intermediate		99,753	**2.2736**	$ 99,753		43,874	$ (70,304)	12.17%
TOTAL	**$ 819,704**	**819,704**		**$ 819,716**	**70,430,634**	**213,588**	**$ (577,707)**	**100.00%**

Transmission Connection Rates

2009 **Not inlcuding RSVA Adjt**

Class	Total Annual Transmission Connection charges - 4716 Cost	% of total kWh (or kW) per class * balance in 4716	New CN Rate	Proof	2009 - kWh	2009 - kW	CN - 4068 Revenue	% of total kWh per class
Residential		$ 219,310	**0.0046**	$ 219,306	47,172,831		$ (292,472)	32.23%
GS<50		$ 94,190	**0.0041**	$ 94,186	22,838,459		$ (125,612)	13.84%
GS>50		$ 275,575	**1.6548**	$ 275,575		166,526.00	$ (367,506)	40.49%
Street Lights		$ 3,922	**1.2793**	$ 3,922		3,066.00	$ (5,231)	0.58%
Sentinel Lights		$ 159	**1.3061**	$ 159		122.00	$ (212)	0.02%
USL		$ 1,729	**0.0041**	$ 1,729	419,344		$ (2,306)	0.25%
Intermediate		$ 85,633	**1.9518**	$ 85,633		43,874.00	$ (114,200)	12.58%
TOTAL	**$ 680,519**	**$ 680,519**		**$ 680,511**	**70,430,634**	**213,588**	**$ (907,539)**	**100.00%**

The following table provides the current and proposed rates for all customer classes:

Network	**Customer Class Name**	**2008 Rate**	**2009 Rate**
kWh	Residential	$0.0039	$0.0055
kWh	General Service Less Than 50 kW	$0.0035	$0.0050
kW	General Service 50 to 2,999 kW	$1.4327	$2.0328
kW	General Service 3,000 to 4,999 kW	$1.6024	$2.2736
kWh	Unmetered Scattered Load	$0.0035	$0.0050
kW	Sentinel Lighting	$1.0860	$1.5409
kW	Street Lighting	$1.0805	$1.5331
Connection	**Customer Class Name**	**2008 Rate**	**2009 Rate**
kWh	Residential	$0.0062	$0.0046
kWh	General Service Less Than 50 kW	$0.0055	$0.0041
kW	General Service 50 to 2,999 kW	$2.2069	$1.6548
kW	General Service 3,000 to 4,999 kW	$2.6029	$1.9518
kWh	Unmetered Scattered Load	$0.0055	$0.0041
kW	Sentinel Lighting	$1.7418	$1.3061
kW	Street Lighting	$1.7061	$1.2793

1

Income and Capital Taxes

Tax Calculations Overview

PILs

This document provides calculations of regulatory taxable income and the associated PIls payable.

	2008 Projection	2009 Projection [1]	2009 Test [1]
Regulatory Taxable Income/(Loss)	112,351	(242,231)	27,040
Combined Income Tax Rate	22.00%	0.00%	22.00%
Total Income Taxes	24,717	0	5,949
Investment & Miscellaneous Tax Credits			
Income Tax Payable	**24,717**	**0**	**5,949**
Large Corporations Tax (LCT)			
Ontario Capital Tax (OCT)	2,319	2,839	2,839
Grossed-up Income Tax			7,627
Grossed-up LCT			
Total PILs Expense	**27,037**	**2,839**	**10,466**

[1] 'Projection' per existing rates; 'Test' based on proposed revenue requirement

Income Tax Rate Calculation	**2008 Projection**	**2009 Projection [1]**	**2009 Test [1]**
Regulatory Taxable Income/(Loss)	112,351	(242,231)	27,040
Interest & Dividend Income	221,000	151,000	151,000
Lesser of (A) and (B) *[zero if negative]*	112,351	0	27,040
Income Tax Rate	*22.00%*	*22.00%*	*22.00%*
Income Tax on Interest & Dividend Income	24,717	0	5,949
Remaining Taxable Income	0	0	0
Income Tax Rate	*0.00%*	*0.00%*	*0.00%*
Income Tax on Remaining Taxable Income	0	0	0
Total Income Tax Payable	**24,717**	**0**	**5,949**
Combined Income Tax Rate	***22.00%***	***0.00%***	***22.00%***

Capital Cost Allowance

Schedule 3 of this Tab displays the CCA by Class for the relevant years for this rate application.

T2

Copies of the T2 tax return document for 2006 and 2007 tax years have been included in Schedule 4 of this Tab.

CT23

Copies of the CT23 tax return document for 2006 and 2007 tax years have been included in Schedule 4 of this Tab.

PILs

Taxable Income

	T2 S1 line #	2006 EDR Approved Tax Return	2006 EDR Approved Utility Only	2008 Projection	2009 @ existing rates	2009 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) [1]		444,876	444,876	**127,836**	44,784	327,473
Additions:						
Interest and penalties on taxes	103		0			0
Amortization of tangible assets	104	578,501	578,501	594,185	638,185	638,185
Loss on disposal of assets	111		0	108		0
Charitable donations	112		0	10,000	0	10,000
Non-deductible meals and entertainment expense	121		0	3,570	3,570	3,570
Reserves from financial statements- balance at end of year	126		0	1,256,220	1,053,329	1,053,329
Actual Debt Interest			0	365,890	365,890	
Total Additions		**578,501**	**578,501**	**2,229,973**	**2,060,974**	**1,705,084**
Deductions:						
Gain on disposal of assets per financial statements	401	35,669	35,669	4,372	0	0
Dividends not taxable under section 83	402		0			0
Capital cost allowance from Schedule 8	403	611,848	611,848	728,573	715,097	715,097
Reserves from financial statements - balance at beginning of year	414		0	1,137,013	1,256,220	1,256,220
Deemed Debt Interest			0	344,101	352,472	
Non-Utility Revenues - 4375			0	260,000	251,000	251,000
Non-Utility Expenses - 4380			0	(238,600)	(226,800)	(226,800)
Total Deductions		**647,517**	**647,517**	**2,235,458**	**2,347,989**	**1,995,517**
NET INCOME (LOSS) FOR TAX PURPOSES		**375,860**	**375,860**	**122,351**	**(242,231)**	**37,040**
Charitable donations from Schedule 2		0	0	10,000	0	10,000
TAXABLE INCOME (LOSS)		**375,860**	**375,860**	**112,351**	**(242,231)**	**27,040**

[1]2008 Projection="Earnings before Tax' (sheet E1); 2009 @ existing rates="Earnings before Tax' (sheet E2); 2009 @ new dist rates="Deemed Return On Equity' (sheet E3)

1 Capital Taxes

	2007		2008		2009	
Paid up capital stock		5,035,066		5,035,066		5,035,066
Retained earnings		2,554,297		532,813		819,538
Loans and advances		5,262,042		5,262,171		5,261,897
Other reserves not allowed						
Ontario sch 8 UCC ending bal	10,779,671		10,559,435		10,659,938	
NBV (G1-groups 1450,1500,1550,1600)	(6,961,518)		(6,802,840)		(6,898,562)	
Post employment benefits	84,853		85,000		85,000	
Regulatory liabilities (G1 Gr 1200)	1,052,160	4,955,166	1,188,622	5,030,217	1,080,264	4,926,640
Paid up capital		17,806,571		15,860,267		16,043,141
Eligible Investments						
shares in other corporations		37,268		37,268		37,268
loans and advances to unrelated corporations		19,655		20,000		20,000
Total eligible investments		56,923		57,268		57,268
Total assets per balance sheet (total asset+adjt for regulatory Liab)		16,861,130		14,537,496		14,690,595
Amounts in 350 and 361 if deducted from assets		4,955,166		5,030,217		4,926,640
Total assets		21,816,296		19,567,713		19,617,235

	2007	2008	2009
Investment allowance (410 / 450) x390	46,461	46,418	46,834
Taxable capital 390-460	17,760,110	15,813,849	15,996,307
Gross revenue (Gr 3000,3050,3070,3100,3150,3200)	13,239,297	14,180,011	14,517,468
Total assets (from BS)	16,861,130	14,537,496	14,690,595
If taxable capital exceeds exemption tax - Ontario capital tax is owing			
	17,760,110	15,813,849	15,996,307
	12,500,000	15,000,000	15,000,000
	5,260,110	813,849	996,307
Ontario allocation 100%			
Capital tax rate .2850%			
Days in taxation year 365			
Ontario capital tax owing --- 2007 owing	**14,991**	**2,319**	**2,839**

1
2

1

	2008	**2009**
OCT (Ontario Capital Tax):		
Taxable Capital	15,813,849	15,996,307
Less: Exemption	15,000,000	15,000,000
Deemed Taxable Capital	813,849	996,307
Tax Rate	0.285%	0.285%
OCT payable	**2,319**	**2,839**
Federal LCT (Large Corporations Tax):		
Taxable Capital	15,813,849	15,996,307
Less: Exemption	50,000,000	50,000,000
Deemed Taxable Capital		
Tax Rate		
LCT payable		

Capital Cost Allowance (CCA)

2006

1		2	3	4	5	6	7	8	9	10	11	12
Class Number	Description	Undepreciated capital cost of the beginning of the year (undepreciated capital cost at the end of last year)	Cost of acquisitions during the year (new property must be available for use)	Net Adjustments	Proceeds of dispositions during the year (amount not to exceed the capital cost)	50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)	Reduced undepreciated capital cost	CCA rate %	Recapture of capital cost allowance (line 108 of Sch 1)	Teminal loss (line 404 of Sch 1)	Capital cost allowance (col 7 x col 8; or lower amount) (line 403 of Sch 1)	Undepreciated capital cost at the end of the year (col 6 + col 7 - col 11)
1		10,170,846	1,500		-	750	10,171,596	4%	0	0	406,864	9,765,482
8		787,467	326,527		-	163,264	950,730	20%	0	0	190,146	923,848
10		161,020	291,460		-	145,730	306,750	30%	0	0	92,025	360,455
10		35,011			-	-	35,011	30%	0	0	10,503	24,508
17		13,016			-	-	13,016	8%	0	0	1,041	11,975
45		3,865	20,459		-	10,230	14,094	45%	0	0	6,342	17,982
12			6,202		-	3,101	3,101	100%	0	0	3,101	3,101
47	Distribution Assets		-		-	-	-	8%	0	0	-	-
50			-		-	-	-	55%	0	0	-	-
	Total	11,171,225	646,148	-	-	323,075	11,494,298		-	-	710,022	11,107,351

2007

1		2	3	4	5	6	7	8	9	10	11	12
Class Number	Description	Undepreciated capital cost of the beginning of the year (undepreciated capital cost at the end of last year)	Cost of acquisitions during the year (new property must be available for use)	Net Adjustments	Proceeds of dispositions during the year (amount not to exceed the capital cost)	50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)	Reduced undepreciated capital cost	CCA rate %	Recapture of capital cost allowance (line 108 of Sch 1)	Teminal loss (line 404 of Sch 1)	Capital cost allowance (col 7 x col 8; or lower amount) (line 403 of Sch 1)	Undepreciated capital cost at the end of the year (col 6 + col 7 - col 11)
1		9,765,482	3,381		-	1,691	9,767,172	4%	0	0	390,687	9,378,176
8		923,848	22,715		38,386		908,177	20%	0	0	181,635	726,542
10		360,455	60,580		-	30,290	390,745	30%	0	0	117,224	303,811
10		24,508			-	-	24,508	30%	0	0	7,352	17,156
17		11,975			-	-	11,975	8%	0	0	958	11,017
45		17,982	19,459		-	9,730	27,711	45%	0	0	12,470	24,971
12		3,101	52,270		-	26,135	29,236	100%	0	0	29,236	26,135
47	Distribution Assets		299,280		-	149,640	149,640	8%	0	0	11,971	287,309
50			6,281		-	3,141	3,141	55%	0	0	1,727	4,554
	Total	11,107,351	463,966	-	38,386	220,627	11,312,304		-	-	753,260	10,779,671

2008

1		2	3	4	5	6	7	8	9	10	11	12
Class Number	Description	Undepreciated capital cost of the beginning of the year (undepreciated capital cost at the end of last year)	Cost of acquisitions during the year (new property must be available for use)	Net Adjustments	Proceeds of dispositions during the year (amount not to exceed the capital cost)	50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)	Reduced undepreciated capital cost	CCA rate %	Recapture of capital cost allowance (line 108 of Sch 1)	Teminal loss (line 404 of Sch 1)	Capital cost allowance (col 7 x col 8; or lower amount) (line 403 of Sch 1)	Undepreciated capital cost at the end of the year (col 6 + col 7 - col 11)
1		9,378,176			3,626	-	9,374,550	4%	0	0	374,982	8,999,568
8		726,542	38,500		58	19,221	745,763	20%	0	0	149,153	615,831
10		320,966			580	-	320,387	30%	0	0	96,116	224,270
17		11,017			-	-	11,017	8%	0	0	881	10,136
45		24,971			-	-	24,971	45%	0	0	11,237	13,735
12		26,135			-	-	26,135	100%	0	0	26,135	-
47	Distribution Assets	287,309	365,100		-	182,550	469,859	8%	0	0	37,589	614,820
50		4,554	109,000		-	54,500	59,054	55%	0	0	32,480	81,074
	Total	10,779,671	512,600	-	4,264	256,271	11,031,736		-	-	728,573	10,559,435

2009

1		2	3	4	5	6	7	8	9	10	11	12
Class Number	Description	Undepreciated capital cost of the beginning of the year (undepreciated capital cost at the end of last year)	Cost of acquisitions during the year (new property must be available for use)	Net Adjustments	Proceeds of dispositions during the year (amount not to exceed the capital cost)	50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)	Reduced undepreciated capital cost	CCA rate %	Recapture of capital cost allowance (line 108 of Sch 1)	Teminal loss (line 404 of Sch 1)	Capital cost allowance (col 7 x col 8; or lower amount) (line 403 of Sch 1)	Undepreciated capital cost at the end of the year (col 6 + col 7 - col 11)
1		8,999,568				-	8,999,568	4%	0	0	359,983	8,639,585
8		615,831	4,000			2,000	617,831	20%	0	0	123,566	496,265
10		224,270	45,000			22,500	246,771	30%	0	0	74,031	195,239
						-						
17		10,136				-	10,136	8%	0	0	811	9,325
45		13,735				-	13,734	45%	0	0	6,180	7,555
12		-				-	-	100%	0	0	-	-
47	Distribution Assets	614,820	655,600			327,800	942,620	8%	0	0	75,410	1,195,010
50		81,074	111,000			55,500	136,574	55%	0	0	75,116	116,958
	Total	10,559,435	815,600	-	-	407,800	10,967,235		-	-	715,097	10,659,938

Federal T2 tax return (2006 & 2007)

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

EXEMPT FROM TAX

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 *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing. For more information on how to complete the return, see the *T2 Corporation – Income Tax Guide* (T4012).

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 on when and how to file T2 returns, refer to the Guide under the heading "Before you start."

055 Do not use this area

CLIENT'S COPY

Identification

Business Number (BN) 001 86547 0769 RC0001

Corporation's name

002 CENTRE WELLINGTON HYDRO LTD.

Has the corporation changed its name since the last time we were notified? 003 1 Yes [ ] 2 No [X]

If *Yes*, do you have a copy of the articles of amendment? . . . 004 1 Yes [ ] 2 No [ ]

Address of head office

Has this address changed since the last time we were notified? . . . . . 010 1 Yes [ ] 2 No [X]

(If *Yes*, complete lines 011 to 018)

011 730 GARTSHORE STREET

012 PO BOX 217

City	Province, territory, or state
015 FERGUS	016 ON
Country (other than Canada)	**Postal code/Zip code**
017	018 N1M 2W8

Mailing address (if different from head office address)

Has this address changed since the last time we were notified? . . . . . 020 1 Yes [ ] 2 No [X]

(If *Yes*, complete lines 021 to 028)

021 c/o

022 730 GARTSHORE STREET

023 PO BOX 217

City	Province, territory, or state
025 FERGUS	026 ON
Country (other than Canada)	**Postal code/Zip code**
027	028 N1M 2W8

Location of books and records

Has the location of books and records changed since the last time we were notified? . . . . . 030 1 Yes [ ] 2 No [X]

(If *Yes*, complete lines 031 to 038)

031 730 GARTSHORE STREET

032 PO BOX 217

City	Province,territory, or state
035 FERGUS	036 ON
Country (other than Canada)	**Postal code/Zip code**
037	038 N1M 2W8

040 Type of corporation at the end of the taxation year

1 [ ] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [X] Other corporation (specify, below)

Tax Exempt

If the type of corporation changed during the tax year, provide the effective date of the change . . . . . 043 YYYY MM DD

To which tax year does this return apply?

Tax year start	Tax year end
060 2006-01-01	061 2006-12-31
YYYY MM DD	YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? 063 1 Yes [ ] 2 No [X]

If *Yes*, provide the date control was acquired . . . . . 065 YYYY MM DD

Is the corporation a professional corporation that is a member of a partnership? . . . . . 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:

Incorporation? . . . . . 070 1 Yes [ ] 2 No [X]

Amalgamation? . . . . . 071 1 Yes [ ] 2 No [X]

If *Yes*, complete lines 030 to 038 and attach Schedule 24.

Has there been a windup of a subsidiary under section 88 during the current tax year? . . . . . 072 1 Yes [ ] 2 No [X]

If *Yes*, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . . 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . . 078 1 Yes [ ] 2 No [X]

Is the corporation a resident of Canada?

080 1 Yes [X] 2 No [ ] If *No*, give the country of residence on line 081 and complete and attach Schedule 97.

081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . . 082 1 Yes [ ] 2 No [X]

If *Yes*, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [X] Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each *Yes* response, attach to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	150		9
Is the corporation an associated Canadian-controlled private corporation?	160		23
Is the corporation an associated Canadian-controlled private corporation that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered *Yes* to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; or gifts of cultural or ecological property?	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
Is the corporation a non-resident-owned investment corporation claiming an allowable refund?	226		26*
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		33/34/35
Is the corporation a member of a related group with one or more members subject to gross Part I.3 tax?	236		36
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax?	255		92 *

*** We do not print this schedule.**

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174

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 ELECTRICITY	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 GIFI. 300 _____ A

Deduct:

Charitable donations from Schedule 2	311	
Gifts to Canada, a province, or a territory from Schedule 2	312	
Cultural gifts from Schedule 2	313	
Ecological gifts from Schedule 2	314	
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320	
Part VI.1 tax deduction from Schedule 43 *	325	
Non-capital losses of preceding tax years from Schedule 4	331	
Net capital losses of preceding tax years from Schedule 4	332	
Restricted farm losses of preceding tax years from Schedule 4	333	
Farm losses of preceding tax years from Schedule 4	334	
Limited partnership losses of preceding tax years from Schedule 4	335	
Taxable capital gains or taxable dividends allocated from a central credit union	340	
Prospector's and grubstaker's shares	350	
Subtotal		▶ B

Subtotal (amount A **minus** amount B) (if negative, enter "0") C

Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions 355 D

Taxable income (amount C **plus** amount D) 360

Income exempt under paragraph 149(1)(t) 370

Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370) Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . . **400** _____ A

Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 3 times the amount on line 636**, and **minus** any amount that, because of federal law, is exempt form Part I tax . . . . . **405** _____ B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

250,000 x (Number of days in the tax year in 2004 / Number of days in the tax year) = _____ 1

300,000 x (Number of days in the tax year in 2005 and in 2006 / Number of days in the tax year) = 300,000 2

400,000 x (Number of days in the tax year after 2006 / Number of days in the tax year) = _____ 3

Add amounts at lines 1, 2, and 3 _____ 4

Business limit (see notes 1 and 2 below) . . . . . **410** _____ 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 _____ x **415** *** _____ D / 11,250 = ... _____ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . **425** _____ F

Small business deduction

Whichever amount is the least A, B, C or F . . . . . _____ G1

Amount G1 _____ x (Number of days in the tax year before 2008 / Number of days in the tax year) 365/365 x 16.00 % = _____ G2

Amount G1 _____ x (Number of days in the tax year in 2008 / Number of days in the tax year) _____/365 x 16.50 % = _____ G3

Amount G1 _____ x (Number of days in the tax year after 2008 / Number of days in the tax year) _____/365 x 17.00 % = _____ G4

Small business deduction – total of amounts G2, G3, and G4 . . . . . **430** _____ G
(enter amount G on line 9)

* 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**

- The amount to be entered at line 415 is the total taxable capital employed in Canada **minus** $10,000,000 x 0.225%, calculated on Schedule 33, *Part I.3 Tax On Large Corporations*, Schedule 34, *Part I.3 Tax On Financial Institutions* **or** Schedule 35, *Part I.3 Tax On Large Insurance Companies*.
- If the corporation is not associated with any corporations in both the current and the preceding tax years, use the applicable schedule for the **prior** year. (Amount **P** in Part 6 of Schedule 33; Amount **O** in Part 6 of Schedule 34; Amount **DD** in Part 6 of Schedule 35)
- If the corporation is not associated with any corporations in the current tax year, but was associated in the preceding tax year, use the applicable schedule for the **current** year.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Accelerated tax reduction

Canadian-controlled private corporations throughout the taxation year that claimed the small business deduction

Reduced business limit (amount from line 425) _____ x 300,000 / line 4 above = _____ A

Net active business income (amount from line 400) * _____ B

Taxable income from line 360 **minus** 3 times the amount at line 636** on, and **minus** any amount that, because of federal law, is exempt from Part I Tax _____ C

Deduct:

Aggregate investment income (amount from line 440) _____ D

Amount C **minus** amount D (if negative, enter "0") _____ ▶ _____ E

Amount A, B, or E above, whichever is less _____ F

Amount Z from Part 9 of Schedule 27 _____ x 100 / 7 = _____ G

Amount QQ from Part 13 of Schedule 27 _____ H

Taxable resource income (amount from line 435) _____ I

Amount used to calculate the credit union deduction (amount E in Part 3 of Schedule 17) _____ J

Amount on line 400, 405, 410, or 425 of the small business deduction, whichever is less _____ K

Total of amounts G, H, I, J, and K _____ ▶ _____ L

Amount F **minus** amount L (if negative, enter "0") _____ M

Accelerated tax reduction – 7.00 % of amount M (enter amount N on line 637) _____ N

* If the amount at line 450 of Schedule 7 is positive, members of partnerships need to use Schedule 70 to calculate net active business income.

** Calculate the amount of foreign business income tax credit deductible at line 636 without reference to the corporate tax reductions under section 123.4.

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)] **435** _____ A

Amount A _____ x Number of days in the tax year in 2004 / Number of days in the tax year 365 x 2 % = _____ B

Amount A _____ x Number of days in the tax year in 2005 / Number of days in the tax year 365 x 3 % = _____ C

Amount A _____ x Number of days in the tax year in 2006 / Number of days in the tax year 365 x 5 % = _____ D

Amount A _____ x Number of days in the tax year after 2006 / Number of days in the tax year 365 x 7 % = _____ E

Resource deduction – total of amounts B, C, D, and E (enter amount F on line 10) **438** _____ F

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 _____ A

Amount Z1 from Part 9 of Schedule 27 _____ B

Amount QQ from Part 13 of Schedule 27 _____ C

Taxable resource income from line 435 above _____ D

Amount used to calculate the credit union deduction (amount E in Part 3 of Schedule 17) _____ E

Amount on line 400, 405, 410, or 425, whichever is the least _____ F

Aggregate investment income from line 440 _____ G

Amount used to calculate the accelerated tax reduction (amount M) _____ H

Total of amounts B, C, D, E, F, G, and H _____ ▶ _____ I

Amount A **minus** amount I (if negative, enter "0") _____ J

Amount J _____ x Number of days in the tax year before 2008 / Number of days in the tax year 365 x 7 % = _____ K1

Amount J _____ x Number of days in the tax year in 2008 / Number of days in the tax year 365 x 7.5 % = _____ K2

Amount J _____ x Number of days in the tax year in 2009 / Number of days in the tax year 365 x 8 % = _____ K3

Amount J _____ x Number of days in the tax year after 2009 / Number of days in the tax year 365 x 9 % = _____ K4

General tax reduction for Canadian-controlled private corporations – total of amounts K1, K2, K3, and K4 (enter amount K on line 638) _____ K

General tax reduction

Corporations other than a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation; and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the full tax rate of 38% (eg. deposit insurance company).

Taxable income from line 360 L

Amount Z1 from Part 9 of Schedule 27 ..... M
Amount QQ from Part 13 of Schedule 27 ..... N
Taxable resource income from line 435 above ..... O
Amount used to calculate the credit union deduction (amount E in Part 3 of Schedule 17) P
Total of amounts M, N, O, and P ..... ▶ Q

Amount L **minus** amount Q (if negative, enter "0") ..... R

Amount R x (Number of days in the tax year before 2008 / Number of days in the tax year) 365 / 365 x 7 % = S1

Amount R x (Number of days in the tax year in 2008 / Number of days in the tax year) / 365 x 7.5 % = S2

Amount R x (Number of days in the tax year in 2009 / Number of days in the tax year) / 365 x 8 % = S3

Amount R x (Number of days in the tax year after 2009 / Number of days in the tax year) / 365 x 9 % = S4

General tax reduction – total of amounts S1, S2, S3, and S4 (enter amount S on line 639) ..... S

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income ..... 440 x 26 2 / 3 % = ... A
(amount O from Part 1 of Schedule 7)

Foreign non-business income tax credit from line 632 .....

Deduct:

Foreign investment income ..... 445 x 9 1 / 3 % =
(amount L from Part 2 of Schedule 7) (if negative, enter "0") ▶ B

Amount A **minus** amount B (if negative, enter "0") C

Taxable income from line 360 .....
Deduct:
Amount on line 400, 405, 410, or 425, whichever is the least .....
Foreign non-business income tax credit from line 632 x 25 / 9 =
Foreign business income tax credit from line 636 x 3 =
▶

x 26 2 / 3 % = D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780) .....
Deduct: Corporate surtax from line 600 .....
Net amount ..... ▶ E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least ..... 450 F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the preceding tax year	460		
Deduct: Dividend refund for the previous tax year	465		
		▶	G
Add the total of:			
Refundable portion of Part I tax from line 450 above			
Total Part IV tax payable from line 360 of Schedule 3			
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480		
		▶	H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H	485		

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3		x 1 / 3	I
Refundable dividend tax on hand at the end of the tax year from line 485 above			J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784)			

Part I tax

Base amount of Part I tax – 38.00 % of taxable income (line 360 or amount Z, whichever applies) . . . . . 550 _____ A

Corporate surtax calculation

Base amount from line A above . . . . . _____ 1

Deduct:

10 % of taxable income (line 360 or amount Z, whichever applies) . . . . . _____ 2

Investment corporation deduction from line 620 below . . . . . _____ 3

Federal logging tax credit from line 640 below . . . . . _____ 4

Federal qualifying environmental trust tax credit from line 648 below . . . . . _____ 5

For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:

28.00 % of taxable income from line 360 . . . . . _____ a

28.00 % of taxed capital gains . . . . . _____ b

Part I tax otherwise payable . . . . . _____ c

(line A **plus** lines C and D **minus** line F) _____ 6

Total of lines 2 to 6 . . . . . _____ 7

Net amount (line 1 **minus** line 7) . . . . . _____ 8

Corporate surtax

line 8 _____ x 4 % x Number of days in the tax year before 2008 / Number of days in the tax year = 365 / 365 = 600 _____ B

Recapture of investment tax credit from line OO in Part 17 of Schedule 31 . . . . . 602 _____ C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 . . . . . _____ i

Taxable income from line 360 . . . . . _____

Deduct:

Amount on line 400, 405, 410, or 425, whichever is the least . . . . . _____

Net amount . . . . . _____ ▶ _____ ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . 604 _____ D

Subtotal (add lines A, B, C, and D) _____ E

Deduct:

Small business deduction from line 430 . . . . . _____ 9

Federal tax abatement . . . . . 608 _____

Manufacturing and processing profits deduction from amount BB or amount RR of Schedule 27 . . . . . 616 _____

Investment corporation deduction . . . . . 620 _____

(taxed capital gains 624 _____)

Additional deduction – credit unions from Schedule 17 . . . . . 628 _____

Federal foreign non-business income tax credit from Schedule 21 . . . . . 632 _____

Federal foreign business income tax credit from Schedule 21 . . . . . 636 _____

Accelerated tax reduction from amount N . . . . . 637 _____

Resource deduction from line 438 . . . . . _____ 10

General tax reduction for CCPCs from amount K . . . . . 638 _____

General tax reduction from amount S . . . . . 639 _____

Federal logging tax credit from Schedule 21 . . . . . 640 _____

Federal political contribution tax credit . . . . . 644 _____

Federal political contributions 646 _____

Federal qualifying environmental trust tax credit . . . . . 648 _____

Investment tax credit from Schedule 31 . . . . . 652 _____

Subtotal _____ ▶ _____ F

Part I tax payable – Line E **minus** line F (enter amount G on line 700) . . . . . _____ G

Summary of tax and credits

Federal tax

Part I tax payable	700	
Part I.3 tax payable from Schedule 33, 34, or 35	704	
Part II surtax payable from Schedule 46	708	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 Ontario
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Québec, Ontario, and Alberta)	760	
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765	
Total tax payable	770	A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Allowable refund for non-resident-owned investment corporations from Schedule 26	804	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	B

Refund code 894 Overpayment

Balance (line A **minus** line B)

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

Certification

I, 950 THIESSEN (Last name) 951 FLORENCE (First name) 954 VICE-PRESIDENT-TREASURER (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2007-05-07 (Date (yyyy/mm/dd)) Signature of the authorized signing officer of the corporation 956 (519) 843-2900 (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 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 ☐

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 1

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

Corporation's name	Business Number	Tax year end Year Month Day
CENTRE WELLINGTON HYDRO LTD.	86547 0769 RC0001	2006-12-31

- 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			152,263 A
Add:			
Subtotal of additions		0 ▶	0
Other additions:			
Miscellaneous other additions:			
Subtotal of other additions	199	0 ▶	0
Total additions	500	0 ▶	0
Deduct:			
Subtotal of deductions		▶	
Other deductions:			
Miscellaneous other deductions:			
700 Exempt from tax under 149(1)(d.6)	390	152,263	
Subtotal of other deductions	499	152,263 ▶	152,263
Total deductions	510	152,263 ▶	152,263
Net income (loss) for income tax purposes – enter on line 300 of the T2 return			0

T2 SCH 1 E (06)

Canada

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
CENTRE WELLINGTON HYDRO LTD.	86547 0769 RC0001	2006-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

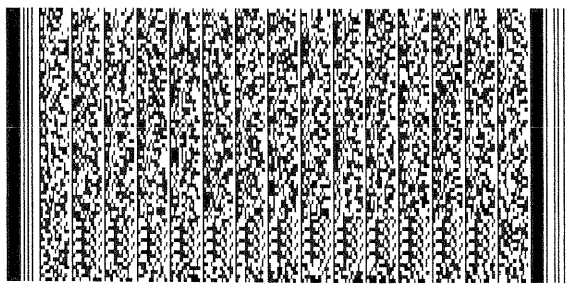
		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	CORPORATION OF THE TOWNSHIP OF CENTRE WELLI	87256 7136 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

T2-RETURN AND SCHEDULE INFORMATION

Name: CENTRE WELLINGTON HYDRO LTD.

BN: 86547 0769 RC 0001 **Taxation Year End: 2006-12-31**

For agency use
[055]



This page must be attached to your return and sent to the Canada Revenue Agency

Name: CENTRE WELLINGTON HYDRO LTD.

BN: 86547 0769 RC 0001 **Taxation Year End: 2006-12-31**

For agency use
[055]

[001] 86547 0769 RC 0001
[060] 2006 01 01
[061] 2006 12 31
[099] EP06
XXXXXXXXXXX

B

[002] CENTRE WELLINGTON HYDRO LTD.

[003] 2
[004] _____
XXXXXXXXXXX

[010]@ 2
[011] _____
[012] _____
[015] _____
[016] _____
[017] _____
[018] _____

For agency use
[091] _____
[092] _____
[093] _____

[020]@ 2
[021] _____
[022] _____
[023] _____
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[028] _____

For agency use
[094] _____
[095] _____
[096] _____
[100] _____

Name: CENTRE WELLINGTON HYDRO LTD.

BN: 86547 0769 RC 0001 **Taxation Year End:** 2006-12-31

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Name: CENTRE WELLINGTON HYDRO LTD.

BN: 86547 0769 RC 0001 **Taxation Year End: 2006-12-31**

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[259]		[286]	
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[262]		[287]	
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[264]		[950]	THIESSEN
[291]	2	[951]	FLORENCE
[292]	2	[954]	VICE-PRESIDENT-TREASURER
[370]		[955]	2007 05 07
[435]		[956]	519 843 2900
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Name: CENTRE WELLINGTON HYDRO LTD.

BN: 86547 0769 RC 0001 Taxation Year End: 2006-12-31

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	XXXXXXXXXXX	[640]		[890]	
		[644]			XXXXXXXXXXX
		[648]			

Name: **CENTRE WELLINGTON HYDRO LTD.**

BN: 86547 0769 RC 0001 **Taxation Year End: 2006-12-31**

Certification

I, FLORENCE THIESSEN am an authorized signing officer of the corporation. I certify that the following amounts are, to the best of my knowledge, correct and complete, and fully disclose the corporation's income tax payable. These amounts also reflect the information given on the corporation's income tax return for the taxation year noted above.

Net income (or loss) for income tax purposes from Schedule 001, or GIFI [line 200300]	0
Part I tax payable [line 200700]	0
Part I.3 tax payable [line 200704]	0
Part II surtax payable [line 200708]	0
Part IV tax payable [line 200712]	0
Part IV.1 tax payable [line 200716]	0
Part VI tax payable [line 200720]	0
Part VI.1 tax payable [line 200724]	0
Part XIV tax payable [line 200728]	0
Net provincial and territoral tax payable [line 200760]	0
Provincial tax on large corporations [line 200765]	0

I further certify that the method of calculating income for this taxation year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

2007-05-07		VICE-PRESIDENT-TREASURER
Date	Signature of an authorized signing officer of the corporation	Position, office or rank

Name: CENTRE WELLINGTON HYDRO LTD.

BN: 86547 0769 RC 0001 **Taxation Year End:** 2006-12-31

[600] _____

[601] _____

[602] _____

[603] _____

[604] _____

[700] Exempt from tax under 149(1)(d.6)

[701] _____

[702] _____

[703] _____

[704] _____

XXXXXXXXXXX

[101] _____

[102] _____

[103] _____

[104] _____

[105] _____

[106] _____

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[218] _____

[219] _____

Name: CENTRE WELLINGTON HYDRO LTD.

BN: 86547 0769 RC 0001 **Taxation Year End:** 2006-12-31

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		[392]			
		[393]			
		[394]			
			XXXXXXXXXXX		

Name: **CENTRE WELLINGTON HYDRO LTD.**

BN: 86547 0769 RC 0001 **Taxation Year End: 2006-12-31**

[100] 1. CORPORATION OF THE TOWNSHIP OF CENTRE WELLINGTON *

[200] 1. 87256 7136 RC 0001 *

[300] 1. _____ *

[350] 1. _____ *

[400] 1. 100 *

[500] 1. _____ *

XXXXXXXXXXX

Name: CENTRE WELLINGTON HYDRO LTD.

BN: 86547 0769 RC 0001 **Taxation Year End: 2006-12-31**

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[1901]	166 701		
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[2589]	1		
[2599]	15 922 396		
	XXXXXXXXXXX		

Name: CENTRE WELLINGTON HYDRO LTD.

BN: 86547 0769 RC 0001 **Taxation Year End: 2006-12-31**

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[8519]	2 423 645
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[8230]	165 571
[8299]	11 824 638
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[8320]	8 974 004
[8518]	8 974 004
[8670]	488 770
[8714]	389 494
[8960]	516 598
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[9284]	728 098
[9367]	2 451 555
[9368]	11 425 559
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Name: CENTRE WELLINGTON HYDRO LTD.

BN: 86547 0769 RC 0001 **Taxation Year End: 2006-12-31**

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[097]	2
[198]	1
[099]	2
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[108]	2

XXXXXXXXXXX

CLIENT'S COPY

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

EXEMPT FROM TAX

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 86547 0769 RC0001

Corporation's name

002 CENTRE WELLINGTON HYDRO LTD.

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)

011 730 GARTSHORE STREET

012 PO BOX 217

City	Province, territory, or state
015 FERGUS	016 ON
Country (other than Canada)	**Postal code/Zip code**
017	018 N1M 2W8

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

022 730 GARTSHORE STREET

023 PO BOX 217

City	Province, territory, or state
025 FERGUS	026 ON
Country (other than Canada)	**Postal code/Zip code**
027	028 N1M 2W8

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)

031 730 GARTSHORE STREET

032 PO BOX 217

City	Province,territory, or state
035 FERGUS	036 ON
Country (other than Canada)	**Postal code/Zip code**
037	038 N1M 2W8

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 DD

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . . 063 1 Yes ☐ 2 No ☒

If **yes**, provide the date control was acquired . . . . . 065 ____ YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? . . . . . 066 1 Yes ☐ 2 No ☒

Is the corporation a professional corporation that is a member of a partnership? . . . . . 067 1 Yes ☐ 2 No ☒

Is this the first year of filing after:

Incorporation? . . . . . 070 1 Yes ☐ 2 No ☒

Amalgamation? . . . . . 071 1 Yes ☐ 2 No ☒

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . . 072 1 Yes ☐ 2 No ☒

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . . 076 1 Yes ☐ 2 No ☒

Is this the final return up to dissolution? . . . . . 078 1 Yes ☐ 2 No ☒

Is the corporation a resident of Canada?

080 1 Yes ☒ 2 No ☐ If **no**, give the country of residence on line 081 and **complete and attach** Schedule 97.

081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . . 082 1 Yes ☐ 2 No ☒

If **yes**, complete and attach Schedule 91.

040 Type of corporation at the end of the tax year

1 ☐ Canadian-controlled private corporation (CCPC)

2 ☐ Other private corporation

3 ☐ Public corporation

4 ☐ Corporation controlled by a public corporation

5 ☒ Other corporation (specify, below)

Tax Exempt

If the type of corporation changed during the tax year, provide the effective date of the change. 043 ____ YYYY MM DD

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085

1 ☐ Exempt under paragraph 149(1)(e) or (l)

2 ☐ Exempt under paragraph 149(1)(j)

3 ☐ Exempt under paragraph 149(1)(t)

4 ☒ Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each *Yes* response, **attach** to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	150		9
Is the corporation an associated CCPC?	160		23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		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 X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281	1 Yes	2 No X

What is the corporation's major business activity? 282
(Only complete if **yes** was entered at line 281)

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale 2 Retail

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	HYDRO ELECTRICITY	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes	2 No X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes	2 No X

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI. 300 A

Deduct:

Charitable donations from Schedule 2	311	
Gifts to Canada, a province, or a territory from Schedule 2	312	
Cultural gifts from Schedule 2	313	
Ecological gifts from Schedule 2	314	
Gifts of medicine from Schedule 2	315	
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320	
Part VI.1 tax deduction *	325	
Non-capital losses of previous tax years from Schedule 4	331	
Net capital losses of previous tax years from Schedule 4	332	
Restricted farm losses of previous tax years from Schedule 4	333	
Farm losses of previous tax years from Schedule 4	334	
Limited partnership losses of previous tax years from Schedule 4	335	
Taxable capital gains or taxable dividends allocated from a central credit union	340	
Prospector's and grubstaker's shares	350	
Subtotal		▶ B
Subtotal (amount A **minus** amount B) (if negative, enter "0")		C

Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions 355 D

Taxable income (amount C **plus** amount D) 360

Income exempt under paragraph 149(1)(t) 370

Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370) Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . . 400 _____ A

Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 3 times the amount on line 636**, and **minus** any amount that, because of federal law, is exempt form Part I tax . . . . . 405 _____ B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

300,000 x (Number of days in the tax year in 2005 and in 2006 / Number of days in the tax year) = _____ 1

400,000 x (Number of days in the tax year after 2006 / Number of days in the tax year) = 400,000 2

Add amounts at lines 1 and 2 400,000 4

Business limit (see notes 1 and 2 below) . . . . . 410 _____ 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 _____ x 415 *** _____ / 11,250 D = _____ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . 425 _____ F

Small business deduction

Amount A, B, C, or F whichever is the least _____ x (Number of days in the tax year before January 1, 2008 / Number of days in the tax year) 365/365 x 16 % = _____ 5

Amount A, B, C, or F whichever is the least _____ x (Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year) ___/365 x 17 % = _____ 6

Amount A, B, C, or F whichever is the least _____ x (Number of days in the tax year after December 31, 2008 / Number of days in the tax year) ___/365 x 17 % = _____ 7

Total of amounts 5, 6, and 7 – enter on line 9 430 _____ G

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and the previous tax years, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)] . . . . . 435 _____ H

Amount H _____ x (Number of days in the tax year in 2005 / Number of days in the tax year) ___/365 x 3 % = _____ I

Amount H _____ x (Number of days in the tax year in 2006 / Number of days in the tax year) ___/365 x 5 % = _____ J

Amount H _____ x (Number of days in the tax year in 2007 / Number of days in the tax year) 365/365 x 7 % = _____ K

Resource deduction – total of amounts I, J and K . . . . . 438 _____ L
Enter amount L on line 10.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360		A
Amount Z1 from Part 9 of Schedule 27	B	
Amount QQ from Part 13 of Schedule 27	C	
Taxable resource income from line 435	D	
Amount used to calculate the credit union deduction (from Schedule 17)	E	
Amount from line 400, 405, 410, or 425, whichever is the least	F	
Aggregate investment income from line 440	G	
Total of amounts B, C, D, E, F, and G ▶		H
Amount A **minus** amount H (if negative, enter "0")		I

Amount I ____ x (Number of days in the tax year before January 1, 2008 / Number of days in the tax year) 365/365 x 7 % = ____ J

Amount I ____ x (Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year) ____/365 x 8.5 % = ____ K

Amount I ____ x (Number of days in the tax year after December 31, 2008 and before January 1, 2010 / Number of days in the tax year) ____/365 x 9 % = ____ K1

Amount I ____ x (Number of days in the tax year after December 31, 2009 and before January 1, 2011 / Number of days in the tax year) ____/365 x 10 % = ____ K2

General tax reduction for Canadian-controlled private corporations – total of amounts J, K, K1, and K2 ____ L
Enter amount L on line 638.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation, and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 (for tax years starting after May 1, 2006, amount Z)		M
Amount Z1 from Part 9 of Schedule 27	N	
Amount QQ from Part 13 of Schedule 27	O	
Taxable resource income from line 435	P	
Amount used to calculate the credit union deduction (from Schedule 17)	Q	
Total of amounts N, O, P, and Q ▶		R
Amount M **minus** amount R (if negative, enter "0")		S

Amount S ____ x (Number of days in the tax year before January 1, 2008 / Number of days in the tax year) 365/365 x 7 % = ____ T

Amount S ____ x (Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year) ____/365 x 8.5 % = ____ U

Amount S ____ x (Number of days in the tax year after December 31, 2008 and before January 1, 2010 / Number of days in the tax year) ____/365 x 9 % = ____ U1

Amount S ____ x (Number of days in the tax year after December 31, 2009 and before January 1, 2011 / Number of days in the tax year) ____/365 x 10 % = ____ U2

General tax reduction – total of amounts T, U, U1, and U2 ____ V
Enter amount V on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income (from Schedule 7) . . . . . 440 _____ x 26 2 / 3 % = ... _____ A

Foreign non-business income tax credit from line 632 . . . . . _____

Deduct:

Foreign investment income (from Schedule 7) . . . . . 445 _____ x 9 1 / 3 % = _____

(if negative, enter "0") _____ ▶ _____ B

Amount A **minus** amount B (if negative, enter "0") . . . . . _____ C

Taxable income from line 360 . . . . . _____

Deduct:

Amount from line 400, 405, 410, or 425, whichever is the least . . . . . _____

Foreign non-business income tax credit from line 632 . . . . . _____ x 25 / 9 = _____

Foreign business income tax credit from line 636 . . . . . _____ x 3 = _____

_____ ▶ _____

x 26 2 / 3 % = _____ D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780) . . . . . _____

Deduct: Corporate surtax from line 600 . . . . . _____

Net amount . . . . . _____ ▶ _____ E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least . . . . . 450 _____ F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . . 460 _____

Deduct: Dividend refund for the previous tax year . . . . . 465 _____

_____ ▶ _____ G

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . . _____

Total Part IV tax payable from Schedule 3 . . . . . _____

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . . 480 _____

_____ ▶ _____ H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H . . . . . 485 _____

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3 . . . . . _____ x 1 / 3 _____ I

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . . _____ J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784) . . . . . _____

Part I tax

Base amount of Part I tax – taxable income (line 360 or amount Z, whichever applies) **multiplied** by 38.00 % . . . . . 550 _____ A

Corporate surtax calculation

Base amount from line A above 1

Deduct:

10 % of taxable income (line 360 or amount Z, whichever applies) 2

Investment corporation deduction from line 620 below 3

Federal logging tax credit from line 640 below 4

Federal qualifying environmental trust tax credit from line 648 below 5

For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:

28.00 % of taxable income from line 360 . . . . . a

28.00 % of taxed capital gains . . . . . b

Part I tax otherwise payable c

(line A **plus** lines C and D **minus** line F) 6

Total of lines 2 to 6 7

Net amount (line 1 **minus** line 7) 8

Corporate surtax*

Line 8 _____ x Number of days in the tax year before January 1, 2008 / Number of days in the tax year = 365 / 365 x 4 % = 600 _____ B

* The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31 . . . . . 602 _____ C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income (if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 i

Taxable income from line 360 . . . . . _____

Deduct:

Amount from line 400, 405, 410, or 425, whichever is the least . . . . . _____

Net amount . . . . . ▶ ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . . 604 _____ D

Subtotal (**add** lines A, B, C, and D) _____ E

Deduct:

Small business deduction from line 430 9

Federal tax abatement 608

Manufacturing and processing profits deduction from Schedule 27 616

Investment corporation deduction 620

(taxed capital gains 624 _____)

Additional deduction – credit unions from Schedule 17 628

Federal foreign non-business income tax credit from Schedule 21 632

Federal foreign business income tax credit from Schedule 21 636

Resource deduction from line 438 10

General tax reduction for CCPCs from amount L 638

General tax reduction from amount V 639

Federal logging tax credit from Schedule 21 640

Federal political contribution tax credit 644

Federal political contributions 646 _____

Federal qualifying environmental trust tax credit 648

Investment tax credit from Schedule 31 652

Subtotal _____ ▶ _____ F

Part I tax payable – Line E **minus** line F . . . . . G

Enter amount G on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	
Part I.3 tax payable from Schedule 33, 34, or 35	704	
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
	Total federal tax	

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 Ontario
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Québec, Ontario, and Alberta)	760	
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765	
	Total tax payable 770	A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld 801		
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
	Total credits 890	B

Refund code 894 ☐ Overpayment

Balance (line A **minus** line B)

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

Certification

I, 950 THIESSEN (Last name in block letters) 951 FLORENCE (First name in block letters) 954 VICE-PRESIDENT-TREASURER (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2008-06-05 (Date (yyyy/mm/dd)) Signature of the authorized signing officer of the corporation

956 (519) 843-2900 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 ☐

Canada Revenue Agency | Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
CENTRE WELLINGTON HYDRO LTD.	86547 0769 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				60,890 A
Add:				
		Subtotal of additions	0 ▶	0
Other additions:				
Miscellaneous other additions:				
		Subtotal of other additions 199	0 ▶	0
		Total additions 500	0 ▶	0
Deduct:				
		Subtotal of deductions	▶	
Other deductions:				
Miscellaneous other deductions:				
700 Exempt from tax under 149(1)(d.6)		390	60,890	
	Total	394		
		Subtotal of other deductions 499	60,890 ▶	60,890
		Total deductions 510	60,890 ▶	60,890
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				0

* For reference purposes only

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
CENTRE WELLINGTON HYDRO LTD.	86547 0769 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) 100	Business Number 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	CORPORATION OF THE TOWNSHIP OF CENTRE WELLI	87256 7136 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

T2 SCH 50 (06)

Canada

T2-RETURN AND SCHEDULE INFORMATION

Name: CENTRE WELLINGTON HYDRO LTD.

BN: 86547 0769 RC 0001

Taxation Year End: 2007-12-31

For agency use
[055]

This page must be attached to your return and sent to the Canada Revenue Agency

T2-RETURN AND SCHEDULE INFORMATION

Name: CENTRE WELLINGTON HYDRO LTD.

BN: 86547 0769 RC 0001 **Taxation Year End: 2007-12-31**

For agency use
[055]

[001] 86547 0769 RC 0001
[060] 2007 01 01
[061] 2007 12 31
[099] EP09
XXXXXXXXXXX

B

[002] CENTRE WELLINGTON HYDRO LTD.

[003] 2
[004] _____
XXXXXXXXXXX

[010]@ 2
[011] _____
[012] _____
[015] _____
[016] _____
[017] _____
[018] _____

For agency use
[091] _____
[092] _____
[093] _____

[020]@ 2
[021] _____
[022] _____
[023] _____
[025] _____
[026] _____
[027] _____
[028] _____

For agency use
[094] _____
[095] _____
[096] _____
[100] _____

Name: CENTRE WELLINGTON HYDRO LTD.

BN: 86547 0769 RC 0001 **Taxation Year End:** 2007-12-31

[030]@	2
[031]	
[032]	
[035]	
[036]	
[037]	
[038]	
	XXXXXXXXXXX

[040]	5	[164]		[216]	
[043]		[165]		[217]	
[063]	2	[166]		[218]	
[065]		[167]		[220]	
[066]	2	[168]		[221]	
[067]	2	[169]		[227]	
[070]	2	[170]		[231]	
[071]	2	[171]		[232]	
[072]	2	[172]		[233]	
[076]	2	[173]	1	[234]	
[078]	2	[201]	1	[236]	
[080]	1	[202]		[237]	
[081]		[203]		[238]	
[082]	2	[204]		[242]	
[085]	4	[205]		[243]	
[150]		[206]		[244]	
[151]		[207]		[249]	
[160]		[208]		[250]	
[161]		[210]		[253]	
[162]		[212]		[254]	
[163]		[213]		[255]	

Name: CENTRE WELLINGTON HYDRO LTD.

BN: 86547 0769 RC 0001 **Taxation Year End:** 2007-12-31

[256]		[990]	1
[258]			XXXXXXXXXXX
[259]			
[260]		[280]	2
[261]		[281]	2
[262]		[282]	
[263]		[283]	
[264]		[284]	HYDRO ELECTRICITY
[265]		[286]	
[266]		[288]	
[267]		[285]	100
[268]		[287]	
[269]		[289]	
[291]	2	[950]	THIESSEN
[292]	2	[951]	FLORENCE
[370]		[954]	VICE-PRESIDENT-TREASURER
[435]		[955]	2008 06 05
[438]		[956]	519 843 2900
[624]		[957]	1
[646]		[958]	
[750]	ON	[959]	
[801]			XXXXXXXXXXX
[894]			
[896]	2		
[898]			
[910]			
[914]			
[918]			

Name: CENTRE WELLINGTON HYDRO LTD.

BN: 86547 0769 RC 0001 **Taxation Year End:** 2007-12-31

[300]	0	[440]		[652]	
[311]		[445]		[700]	
[312]		[450]			XXXXXXXXXXX
[313]		[600]			
[314]		[632]		[704]	
[315]		[636]		[708]	
[320]		[780]		[710]	
[325]			XXXXXXXXXXX	[716]	
[331]				[720]	
[332]		[460]		[724]	
[333]		[465]		[727]	
[334]		[480]		[728]	
[335]		[485]		[760]	
[340]		[712]		[765]	
[350]			XXXXXXXXXXX	[770]	
[355]					XXXXXXXXXXX
[360]		[550]			
	XXXXXXXXXXX	[602]		[784]	
		[604]		[788]	
[400]		[608]		[792]	
[405]		[616]		[796]	
[410]		[620]		[797]	
[425]		[628]		[800]	
[430]		[638]		[808]	
	XXXXXXXXXXX	[639]		[812]	
		[640]		[840]	
[415]		[644]		[890]	
	XXXXXXXXXXX	[648]			XXXXXXXXXXX

Name: CENTRE WELLINGTON HYDRO LTD.

BN: 86547 0769 RC 0001 **Taxation Year End: 2007-12-31**

Certification

I, FLORENCE THIESSEN am an authorized signing officer of the corporation. I certify that the following amounts are, to the best of my knowledge, correct and complete, and fully disclose the corporation's income tax payable. These amounts also reflect the information given on the corporation's income tax return for the taxation year noted above.

Net income (or loss) for income tax purposes from Schedule 001, or GIFI [line 200300]	0
Part I tax payable [line 200700]	0
Part I.3 tax payable [line 200704]	0
Part II surtax payable [line 200708]	0
Part III.1 tax payable [line 200710]	0
Part IV tax payable [line 200712]	0
Part IV.1 tax payable [line 200716]	0
Part VI tax payable [line 200720]	0
Part VI.1 tax payable [line 200724]	0
Part XIV tax payable [line 200728]	0
Net provincial and territoral tax payable [line 200760]	0
Provincial tax on large corporations [line 200765]	0

SIGN HERE

I further certify that the method of calculating income for this taxation year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

2008 06 05	VICE-PRESIDENT-TREASURER
Date	Signature of an authorized signing officer of the corporation — Position, office or rank

Name: CENTRE WELLINGTON HYDRO LTD.

BN: 86547 0769 RC 0001 **Taxation Year End:** 2007-12-31

[600] _____

[601] _____

[602] _____

[603] _____

[604] _____

[700] Exempt from tax under 149(1)(d.6)

[701] _____

[702] _____

[703] _____

[704] _____

XXXXXXXXXXX

[101] _____

[102] _____

[103] _____

[104] _____

[105] _____

[106] _____

[107] _____

[108] _____

[109] _____

[110] _____

[111] _____

[112] _____

[113] _____

[114] _____

[115] _____

[116] _____

[117] _____

[118] _____

[119] _____

[120] _____

[121] _____

[122] _____

[123] _____

[124] _____

[125] _____

[126] _____

[127] _____

[128] _____

[199] _____

[500] _____

XXXXXXXXXXX

[201] _____

[202] _____

[203] _____

[204] _____

[205] _____

[206] _____

[207] _____

[208] _____

[209] _____

[210] _____

[211] _____

[212] _____

[213] _____

[214] _____

[215] _____

[216] _____

[217] _____

[218] _____

[219] _____

Name: CENTRE WELLINGTON HYDRO LTD.

BN: 86547 0769 RC 0001 **Taxation Year End:** 2007-12-31

[220]		[300]		[401]	
[221]		[301]		[402]	
[222]		[302]		[403]	
[223]		[303]		[404]	
[224]		[304]		[405]	
[225]		[305]		[406]	
[226]		[306]		[407]	
[227]		[307]		[408]	
[228]		[308]		[409]	
[229]		[309]		[410]	
[230]		[310]		[411]	
[231]		[311]		[413]	
[232]		[312]		[414]	
[233]		[313]		[416]	
[234]		[314]		[417]	
[235]		[315]		**[499]**	60 890
[236]		[316]		[510]	60 890
[237]		[340]			**XXXXXXXXXXX**
[238]		[341]			
[290]		[342]			
[291]		[343]			
[292]		[344]			
[293]		[345]			
[294]		[346]			
	XXXXXXXXXXX	[390]	60 890		
		[391]			
		[392]			
		[393]			
		[394]			
			XXXXXXXXXXX		

T2-RETURN AND SCHEDULE INFORMATION

050

Name: **CENTRE WELLINGTON HYDRO LTD.**

BN: 86547 0769 RC 0001 **Taxation Year End: 2007-12-31**

[100] 1. CORPORATION OF THE TOWNSHIP OF CENTRE WELLINGTON *

[200] 1. 87256 7136 RC 0001 *

[300] 1. _____ *

[350] 1. _____ *

[400] 1. 100 *

[500] 1. _____ *

XXXXXXXXXXX

Name: CENTRE WELLINGTON HYDRO LTD.

BN: 86547 0769 RC 0001 **Taxation Year End: 2007-12-31**

[3640]	16 861 130	[2680]	288 381
	XXXXXXXXXXX	[2960]	215 289
		[3139]	3 088 001
[1000]	6 474 904	[3140]	5 046 753
[1060]	1 875 121	[3320]	84 853
[1120]	208 041	[3325]	1 052 160
[1480]	1 269 263	[3450]	6 183 766
[1484]	35 015	[3499]	9 271 767
[1599]	9 862 344		XXXXXXXXXXX
[1600]	85 395		
[1602]	# 3 562	[3500]	5 035 066
[1680]	1 022 541	[3540]	37 267
[1681]	# 214 265	[3600]	2 517 030
[1740]	12 732 596	[3620]	7 589 363
[1741]	# 6 744 562		XXXXXXXXXXX
[1742]	840 271		
[1743]	# 420 843	[3660]	2 456 145
[1774]	313 666	[3680]	60 890
[1775]	# 236 563	[3740]	# 5
[1785]	547 335	[3849]	2 517 030
[1900]	# 1 174 167		XXXXXXXXXXX
[1901]	213 676		
[2008]	14 367 637		
[2009]	# 7 406 119		
[2300]	37 268		
[2589]	37 268		
[2599]	16 861 130		
	XXXXXXXXXXX		
[2600]	_____		
[2620]	2 584 331		

Name: CENTRE WELLINGTON HYDRO LTD.

BN: 86547 0769 RC 0001 **Taxation Year End: 2007-12-31**

[0001]	
[0002]	
	XXXXXXXXXXX
[0003]	
	XXXXXXXXXXX

[8519]	2 445 290
[9369]	512 717
[9899]	
[9970]	512 717
[9975]	
[9976]	
[9980]	
[9985]	
[9990]	451 827
[9995]	
[9999]	60 890
	XXXXXXXXXXX
[8000]	12 728 214
[8089]	12 728 214
[8090]	263 280
[8230]	247 803
[8299]	13 239 297
	XXXXXXXXXXX
[8300]	
[8320]	10 282 924
[8518]	10 282 924
[8670]	511 313

[8714]	389 567
[8960]	551 999
[9270]	314 401
[9284]	676 376
[9367]	2 443 656
[9368]	12 726 580
	XXXXXXXXXXX
[9370]	
[9659]	0
	XXXXXXXXXXX
[9660]	
[9898]	0
	XXXXXXXXXXX

Name: **CENTRE WELLINGTON HYDRO LTD.**

BN: 86547 0769 RC 0001 **Taxation Year End: 2007-12-31**

[095]	1
[097]	2
[198]	1
[099]	2
[101]	1
[102]	2
[103]	1
[104]	2
[105]	2
[106]	2
[107]	1
[108]	2
	XXXXXXXXXXX

Canada Revenue Agency / Agence du revenu du Canada

BUSINESS CONSENT FORM

Complete this form to consent to the release of confidential information about your Business Number (BN) account(s) to the representative named below, or to cancel consent for an existing representative. **Send this completed form to your tax centre**. You can also give or cancel consent by providing the requested information online through My Business Account at **www.cra.gc.ca/mybusinessaccount**.

Note: Read all instructions on the last page before completing this form.

Part 1 – Business Information – Complete this part to identify your business (all fields have to be completed)

Business Name: CENTRE WELLINGTON HYDRO LTD.

Business Number: 865470769 Telephone Number: (519) 843-2900

Part 2 – Authorize a representative

If you are giving consent for an individual, enter that person's full name or if you are giving consent to a firm, enter the name of the firm and the BN. If you want us to deal with a specific individual in that firm, enter **both** the individual's name and the name of the firm. If you do not identify an individual of the firm then you are giving us consent to deal with anyone from that firm.

Name of Individual:

Name of Firm: KPMG LLP

Telephone Number: (519) 747-8800 Extension: **BN:** 122363153

Authorize online access

You can authorize your representative to deal with us through our online services for representatives. You have to provide the RepID of the individual or the Business Number of the firm indicated above. The name of the firm provided above must be the same name that is registered with the Represent a Client service at **www.cra.gc.ca/representatives**. If the firm names differ then online access will not be granted. Our online services do not have a year specific option, so your representative will have access to all years.

RepID: (for above individual) **OR** **BN:** 122363153
The BN must be registered with the Represent a Client service to be an online representative.

Part 3 – Which Accounts and Which Years?

i) Accounts – Select which accounts the above individual or firm is authorized to access (check only box A or B).

A. [X] This authorization applies to all BN accounts and all years. **Note: online access is available for box A only.**

Expiry date:

OR

B. [ ] This authorization applies only to the BN accounts and periods listed in Part 3ii.

Authorization level: check one box

[X] Disclose information only

OR

[ ] Disclose information **and** make changes to your BN account(s)

BUSINESS CONSENT FORM (RC59 continued)

ii) Details of accounts and fiscal periods – Complete this area if you checked box "B" in Part 3 i) on the first page.

If you checked box B in part 3i, you have to provide at least one program identifier (see Instructions on the last page). You can then check the "all accounts" box for that program identifier or enter a specific account number. Provide the authorization level ("1" to disclose information or "2" to disclose information and make changes). You can also check the "All years" box to allow unlimited tax year access or enter a specific fiscal period **(specific period authorization is not available for online access)**. You can also enter an expiry date to automatically cancel authorization. If additional authorizations or more than four program identifiers are needed complete another RC59.

Program identifier	All accounts		Specific account	Authorization level	All years		Specific fiscal period (not available for online access)	Expiry date
	☐	or			☐	or		
	☐	or			☐	or		
	☐	or			☐	or		
	☐	or			☐	or		

Part 4 – Cancel one or more existing authorizations – Complete this section **only** to cancel existing authorization(s)

☐ **A.** Cancel **all** authorizations.

☐ **B.** Cancel authorization for the individual or firm identified below.

Name of Individual: _____

Name of Firm: _____

Part 5 – Certification

SIGN HERE

This form must be signed by an authorized person of the business such as a proprietor of a proprietorship, a partner of a partnership, a director of a corporation, an officer of a non profit organization or a trustee of an estate.
By signing and dating this form, you authorize the CRA to deal with the individual or firm listed in Part 2 of this form and/or cancel the authorizations listed in Part 4.

First name: FLORENCE Last name: THIESSEN

Title: VICE-PRESIDENT-TREASURER

Sign here ▶ _____ Date 2008-06-05

WE WILL NOT PROCESS THIS FORM UNLESS IT IS SIGNED AND DATED BY AN AUTHORIZED PERSON OF THE BUSINESS.

Ontario CT23 tax return (2006 & 2007)

CLIENT'S COPY

Attachment to CT23 Corporations Tax and Annual Return

Centre Wellington Hydro Ltd.
Ontario Corporation Tax Account # 1800241

Taxes payable for the year ended December 31, 2006 are comprised of:

Federal Large Corporations Tax	-
Federal Income Tax	101,993
Federal Part IV Tax	123
Provincial Corporations Tax	42,868
Provincial Corporate Minimum Tax	
Provincial Capital Tax	21,205
Total Provincial Payment in Lieu of Taxes	$ 166,189
Less: Provincial instalments paid	(175,806)
Balance owing (refund)	$ (9,617)

Ontario

Ministry of Finance
Corporations Tax
33 King Street West
PO Box 622
Oshawa ON L1H 8H6

Authorizing or Cancelling a Representative

Complete this form to:

- **authorize** the release of confidential information about the Corporations Tax, Mining Tax or Electricity Act account(s) to the representative named below.
- **cancel** an existing authorization.

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	2006-12-31

Part 1 Client Information

Legal Name: CENTRE WELLINGTON HYDRO LTD.
Phone number: (519) 843-2900

Mailing address
Apt./Suite/Unit no. Street number and name / PO Box, RR: 730 GARTSHORE STREET PO BOX 217
City: FERGUS
Province/Territory: ON
Postal code: N1M 2W8

This authorization applies to the following statute(s) and account number(s).

- [X] **Corporations Tax Act** 1800241
- [ ] **Mining Tax Act**
- [ ] **Electricity Act**

Part 2 Authorize the release of information to a representative

Name of representative (If a firm, name of firm.)
Last: KPMG LLP
First:
Phone number: (519) 747-8800
Fax number: (519) 747-8890

Mailing address
Apt./Suite/Unit no. Street number and name / PO Box, RR: 115 King Street South 2nd Floor
City: WATERLOO
Province/Territory: ON
Postal code: N2J 5A3

If your representative is a firm, and you want a specific person in the firm to represent you, state their name and title.
If you do not identify a specific individual in the firm, you are authorizing the Ministry of Finance to deal with anyone from that firm.

Name of person in firm
Last:
First:
Title:

Part 3 Authorization scope and applicable years

- [X] Representative to **deal fully** on your behalf with the Ministry of Finance.

or

- [ ] Representative to **deal in a limited manner** on your behalf, for matters specified here. (e.g., account inquiry, applications, annual returns, payments, etc.) ▼

- [X] Representative to act for **all years**, including all previous and future years.

or

- [ ] Representative to act for **specific year or years** (describe). ▼

Part 4 Cancel the release of information to a representative

Name of representative (If a firm, name of firm.)
Last:
First:

If your representative is an individual within a firm, state their name and title.

Name of person in firm
Last:
First:
Title:

Part 5 Signature *This form will not be accepted unless it is completed fully, signed and dated.*

I authorize the Ministry of Finance to:

- release confidential information about the tax accounts specified in Part 1 and to deal with the representative named in Part 2 in the manner described in Part 3; and/or
- cancel an existing authorization as described in Part 4.

Name
Last: THIESSEN
First: FLORENCE
Title / Relationship to Corporation: VICE-PRESIDENT-TREASURER
Phone number: (519) 843-2900

Signature:
Date: 2007-05-21

Ontario

Ministry of Finance
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

2006 CT23 Corporations Tax and Annual Return

For taxation years commencing after December 31, 2003

Corporations Tax Act – Ministry of Finance (MOF)
Corporations Information Act – Ministry of Government Services (MGS)

This form is a combination of the Ministry of Finance (MOF) **CT23 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)* [X] Yes [ ] No

Ministry Use

Corporation's Legal Name *(including punctuation)*

CENTRE WELLINGTON HYDRO LTD.

Ontario Corporations Tax Account No. (MOF)

1800241

Mailing Address

730 GARTSHORE STREET
PO BOX 217
FERGUS
ON CA N1M 2W8

This Return covers the Taxation Year

Start: year month day — 2006-01-01

End: year month day — 2006-12-31

Has the mailing address changed since last filed CT23 Return? [ ] Yes

Date of Change: year month day

Date of Incorporation or Amalgamation

year month day — 2000-08-22

Registered/Head Office Address

730 GARTSHORE STREET
PO BOX 217
FERGUS
ON CA N1M 2W8

Ontario Corporation No. (MGS) — 1435240

Location of Books and Records

730 GARTSHORE STREET
PO BOX 217
FERGUS
ON CA N1M 2W8

Canada Revenue Agency Business No.

If applicable, enter — 86547 0769 RC0001

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
FLORENCE THIESSEN	(519) 843-2900	

Jurisdiction Incorporated — Ontario

Address of Principal Office in Ontario *(Extra-Provincial Corporations only)* (MGS)

Ontario Canada

If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased:

Commenced: year month day

Ceased: year month day

Former Corporation Name *(Extra-Provincial Corporations only)* [X] *Not Applicable* (MGS)

[X] *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). ▶

No. of Schedule(s)

If there is **no change** to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check (X) this box. Schedule(s) A and K are not required (MGS). ▶ [X] **No Change**

Preferred Language / *Langue de préférence*

[X] English *anglais* [ ] French *français*

Ministry Use

Certification (MGS)

I certify that all information set out in the **Annual Return** is true, correct and complete.

Name of Authorized Person *(Print clearly or type in full)*

FLORENCE THIESSEN

Title: D [ ] Director O [X] Officer P [ ] Other individuals having knowledge of the Corporation's business activities

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

Please check applicable (X) box(es) and complete required information.

Type of corporation

1

1 [X] Canadian-controlled Private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))

2 [ ] Other Private

3 [ ] Public

4 [ ] Non-share Capital

5 [ ] Other *(specify)* ▼

Share Capital with full voting rights owned by Canadian Residents (nearest percent) 100 %

2

1 [ ] Family Farm corporation s.1(2)

2 [ ] Family Fishing corporation s.1(2)

3 [ ] Mortgage Investment corporation s.47

4 [ ] Credit Union s.51

5 [ ] Bank Mortgage subsidiary s.61(4)

6 [ ] Bank s.1(2)

7 [ ] Loan and Trust corporation s.61(4)

8 [ ] Non-resident corporation s.2(2)(a) or (b)

9 [ ] Non-resident corporation s.2(2)(c)

10 [ ] Mutual Fund corporation s.48

11 [ ] Non-resident owned Investment corporation s.49

12 [ ] Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)

14 [ ] Bare Trustee corporation

15 [ ] Branch of Non-resident s.63(1)

16 [ ] Financial institution prescribed by Regulation only

17 [ ] Investment Dealer

18 [ ] Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale

19 [X] Hydro successor, municipal electrical utility or subsidiary of either

20 [ ] Producer and seller of steam for uses other than for the generation of electricity

21 [ ] Insurance Exchange s.74.4

22 [ ] Farm Feeder Finance Co-operative corporation

23 [ ] Professional corporation (incorporated professionals only)

[ ] This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)

[ ] Amended Return

[ ] Taxation year end change – Canada Revenue Agency approval required

[ ] Final taxation year up to dissolution *(Note: for discontinued businesses, see guide.)*

[ ] Final taxation year before amalgamation

[ ] The corporation has a floating fiscal year end

[ ] There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario

[ ] There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year

If checked, date control was acquired year month day

[ ] The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)

[ ] First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)

[ ] Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes	No	
[ ]	[X]	Was the corporation inactive throughout the taxation year?
[X]	[ ]	Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?

Are you requesting a refund due to:

[ ]	[X]	the Carry-back of a Loss?
[X]	[ ]	an Overpayment?
[ ]	[X]	a Specified Refundable Tax Credit?
[ ]	[X]	Are you a member of a Partnership or Joint Venture?

Complete if applicable

Ontario Retail Sales Tax Vendor Permit no. (Use head office no.)

Ontario Employer Health Tax Account no. (Use head office no.)

Specify major business activity

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	593,384 .
Subtract: Charitable donations	–	1	81,225 .
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	369 .
Subtract: Ontario political contributions *(Attach Schedule 2A)* (Int.B. 3002R)	–	4	.
Subtract: Federal Part VI.1 tax . x 3	–	5	.
Subtract: Prior years' losses applied – Non-capital losses From 715	–	From 704	.
Net capital losses (page 16) . x inclusion rate 50.000000 % =	–	714	.
Farm losses	–	From 724	.
Restricted farm losses	–	From 734	.
Limited partnership losses	–	From 754	.
Taxable Income (Non-capital loss)	=	10	511,790 .
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	511,790 .

Taxable Income

Number of Days in Taxation Year

From 10 (or 20 if applicable)	511,790 .	x	30	100.0000 % Ontario Allocation	x	12.5 %	x	Days after Dec. 31, 2002 and before Jan. 1, 2004 33	÷	Total Days 73 365	= +	29	.
From 10 (or 20 if applicable)	511,790 .	x	30	100.0000 % Ontario Allocation	x	14 %	x	Days after Dec. 31, 2003 34 365	÷	Total Days 73 365	= +	32	71,651 .
Income Tax Payable (before deduction of tax credits) 29 + 32											=	40	71,651 .

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

If this section is not completed, the IDSBC will be denied.

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? (X) [X] Yes [ ] No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))		50	593,015 .
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	+ 51	511,790 .	
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	.	
	=	511,790 .	54 511,790 .
Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1)		55	300,000 .

Ontario Business Limit Calculation

320,000 x Days after Dec. 31, 2002 and before Jan. 1, 2004: 31 ÷ ** 365 = + 46 .

400,000 x Days after Dec. 31, 2003: 34 365 ÷ ** 365 = + 47 400,000 .

Business Limit for Ontario purposes 46 + 47 = 44 400,000 . x Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated. 48 100.0000 % = 45 400,000 .

Income eligible for the IDSBC From 30 100.0000 % ***Ontario Allocation x 56 400,000 . = 60 400,000 .
Least of 50 , 54 or 45

* ***Note:*** *Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)*

** ***Note:*** *Adjust accordingly for a floating taxation year and use 366 for a leap year.*

*** ***Note:*** *Ontario Allocation for IDSBC purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).*

continued on Page 5

Income Tax *continued from Page 4*

Calculation of IDSBC Rate - - - - - - - - - - - - - - - - 7 % x (Number of Days in Taxation Year: Days after Dec. 31, 2002 and before Jan. 1, 2004 [31] ÷ Total Days [73] 365) = + [89]

8.5 % x (Days after Dec. 31, 2003 [34] 365 ÷ Total Days [73] 365) = + [90] 8.5000

IDSBC Rate for Taxation Year [89] + [90] - = [78] 8.5000

Claim - - - - - - - - - - - - - - - - From [60] 400,000 . x From [78] 8.5000 % - - - = [70] 34,000 .

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount 400,000 in [114] below.

Surtax on Canadian-controlled Private Corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

Associated Corporation - The Taxable Income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

***Taxable Income of the corporation** - - - - - - - - - - - - - - - - - - From [10] (or [20] if applicable) + [80] 511,790 .

If you are a member of an associated group (X) [81] [ ] (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	* Taxable Income (if loss, enter nil)
			+ [82] .
			+ [83] .
			+ [84] .

Aggregate Taxable Income [80] + [82] + [83] + [84], etc. - - - - - - - - - - - - - - - - = [85] 511,790 .

Number of Days in Taxation Year

320,000 x (Days after Dec. 31, 2002 and before Jan. 1, 2004 [31] ÷ Total Days [73] 365) = + [115] .

400,000 x (Days after Dec. 31, 2003 [34] 365 ÷ Total Days [73] 365) = + [116] 400,000 .

[115] + [116] = 400,000 . ▶ - - - - - - - - - [114] 400,000 .

(If negative, enter nil) - = [86] 111,790 .

Calculation of Specified Rate for Surtax - - - - - - - - - 4.6670 % x (Number of Days in Taxation Year: Days after Dec. 31, 2002 [38] 365 ÷ Total Days [73] 365) = + [97] 4.6670

From [86] 111,790 . x From [97] 4.6670 % - - - - - - - - - - - = [87] 5,217 .

From [87] 5,217 . x From [60] 400,000 . ÷ From [114] 400,000 . = [88] 5,217 .

Surtax Lesser of [70] or [88] - = [100] 5,217

* ***Note: Short Taxation Years*** – Special rules apply where the taxation year is less than 51 weeks for the corporation and/or any corporation associated with it.

continued on Page 6

Additional Deduction for Credit Unions (s.51(4)) *(Attach schedule 17)* - - - - - - - - - - - 110

Manufacturing and Processing Profits Credit (M&P) (s.43)

Applies to Eligible Canadian Profits from manufacturing and processing, farming, mining, logging and fishing carried on in Canada, as determined by regulations.

Eligible Canadian Profits from mining are the "resource profits from the mining operations", as determined for Ontario depletion purposes, after deducting depletion and resource allowances but excluding amounts from sale of Canadian resource property, rentals or royalties. If you are claiming this credit, attach a copy of Ontario schedule 27.

The whole of the active business income qualifies as Eligible Canadian Profits if: **a)** your active business income from sources other than manufacturing and processing, mining, farming, logging or fishing is 20% or less of the total active business income and **b)** the total active business income is $250,000 or less.

Eligible Canadian Profits - + 120

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) - - - - - - - - - From 56 400,000

Add: Adjustment for Surtax on Canadian-controlled private corporations

From 100 5,217 ÷ From 30 100.0000 % ÷ From 78 8.5000 % = 121 61,376

*Ontario Allocation

Lesser of 56 or 121 - + 122 61,376

120 – 56 + 122 - = 130

Taxable Income - + From 10 511,790

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 61,376

Subtract: Taxable Income 10 511,790 X Allocation % to jurisdictions outside Canada _____ % - - - 140

Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses - - - - - - - - 141

10 – 56 + 122 – 140 – 141 - = 142 173,166

Claim

143 Lesser of 130 or 142	X	From 30 100.0000 % Ontario Allocation	X	1.5 %	X	Days after Dec. 31, 2002 and before Jan. 1, 2004: 33 ÷ Total Days 73 365	= +	154			
143 Lesser of 130 or 142	X	From 30 100.0000 % Ontario Allocation	X	2 %	X	Days after Dec. 31, 2003: 34 365 ÷ Total Days 73 365	= +	156			

Number of Days in Taxation Year

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 42,868

continued on Page 7

Income Tax *continued from Page 6*

Specified Tax Credits *(Refer to Guide)*

Ontario Innovation Tax Credit (OITC) (s.43.3) ***Applies*** to scientific research and experimental development in Ontario.
Eligible Credit From 5620 OITC Claim Form *(Attach original Claim Form)* + 191

Co-operative Education Tax Credit (CETC) (s.43.4) ***Applies*** to employment of eligible students.
Eligible Credit From 5798 CT23 Schedule 113 *(Attach Schedule 113)* + 192

Ontario Film & Television Tax Credit (OFTTC) (s.43.5)
Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. Name of Production 204
Eligible Credit From 5850 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 193

Graduate Transitions Tax Credit (GTTC) (s.43.6) No. of Graduates From 6596
Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005. 194
Eligible Credit From 6598 CT23 Schedule 115 *(Attach Schedule 115)* + 195

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)
Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.
Eligible Credit From 6900 OBPTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + 196

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)
Applies to labour relating to computer animation and special effects on an eligible production.
Eligible Credit From 6700 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 197

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)
Applies to qualifying R&D expenditures under an eligible research institute contract.
Eligible Credit From 7100 OBRITC Claim Form *(Attach original Claim Form)* + 198

Ontario Production Services Tax Credit (OPSTC) (s.43.10)
Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.
Eligible Credit From 7300 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 199

Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)
Applies to qualifying labour expenditures of eligible products for the taxation year.
Eligible Credit From 7400 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 200

Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)
Applies to qualifying expenditures in respect of eligible Canadian sound recordings.
Eligible Credit From 7500 OSRTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + 201

Apprenticeship Training Tax Credit (ATTC) (s.43.13) No. of Apprentices From 5896
Applies to employment of eligible apprentices. 202
Eligible Credit From 5898 CT23 Schedule 114 *(Attach Schedule 114)* + 203

Other (specify) _____ + 203.1

Total Specified Tax Credits 191 + 192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 + 203 + 203.1 = 220

Specified Tax Credits ***Applied to reduce Income Tax*** = 225

Income Tax 190 – 225 **OR Enter NIL if reporting Non-Capital Loss** *(amount cannot be negative)* = 230 42,868

To determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see **Determination of Applicability** section for the CMT on **Page 8.** If CMT is not applicable, transfer amount in 230 to Income Tax in **Summary** section on **Page 17.**

OR

If CMT is not applicable for the current taxation year but your corporation has CMT Credit Carryovers that you want to apply to reduce income tax otherwise payable, then proceed to and complete the **Application of CMT Credit Carryovers** section part B, on **Page 8.**

Corporate Minimum Tax (CMT)

DOLLARS ONLY

Total Assets of the corporation	+ 240	15,922,396 .	
Total Revenue of the corporation		+ 241	11,824,638 .

The above amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

If you are a member of an associated group (X) 242 ☐ (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Total Assets	Total Revenue
			+ 243 .	+ 244 .
			+ 245 .	+ 246 .
			+ 247 .	+ 248 .
Aggregate Total Assets 240 + 243 + 245 + 247 , etc.			= 249 15,922,396 .	
Aggregate Total Revenue 241 + 244 + 246 + 248 , etc.				= 250 11,824,638 .

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 398,710 . (If negative, enter zero) × From 30 100.0000 % (Ontario Allocation) × 4 % = 276 15,948 .

Subtract: Foreign Tax Credit for CMT purposes *(Attach Schedule)* — 277

Subtract: Income Tax — From 190 42,868 .

Net CMT Payable (If negative, enter Nil on Page 17.) = 280 -26,920 .

If 280 is less than zero and you do not have a CMT credit carryover, transfer 230 from **Page 7** to **Income Tax Summary, on Page 17.**

If 280 is less than zero and you have a CMT credit carryover, complete A & B below.

If 280 is greater than or equal to zero, transfer 230 to **Page 17** and transfer 280 to **Page 17, and** to **Part 4 of Schedule 101: Continuity of CMT Credit Carryovers.**

CMT Credit Carryover available From Schedule 101 — From 2333

Application of CMT Credit Carryovers

A.

Income Tax (before deduction of specified credits)		+ From 190	42,868 .
Gross CMT Payable	+ From 276 15,948 .		
Subtract: Foreign Tax Credit for CMT purposes	– From 277 .		
If 276 – 277 is negative, enter NIL in 290	= 15,948 . ▶	– 290	15,948 .
Income Tax eligible for CMT Credit		= 300	26,920 .

B.

Income Tax (after deduction of specified credits)		+ From 230	42,868 .
Subtract: CMT credit used to reduce income taxes		– 310	.
Income Tax		= 320	42,868 .

Transfer to page 17

If A & B apply, 310 ***cannot exceed the lesser of*** 230 , 300 ***and your CMT credit carryover available*** 2333 .

If only B applies, 310 ***cannot exceed the lesser of*** 230 ***and your CMT credit carryover available*** 2333 .

Capital Tax *(Refer to Guide and Int.B. 3011R)*

If your corporation is a Financial Institution (s.58(2)), complete lines 480 *and* 430 *on page 10 then proceed to page 13.*

If your corporation is not a member of an associated group and/or partnership and the Gross Revenue and Total Assets as calculated on page 10 in 480 *and* 430 *are both $3,000,000 or less, your corporation is exempt from Capital Tax for the taxation year, except for a branch of a non-resident corporation. A corporation that meets these criteria should disregard all other Capital Tax items (including the calculation of Taxable Capital). Enter NIL in* 550 *on page 12 and complete the return from that point. All other corporations must compute their Taxable Capital in order to determine their Capital Tax payable.*

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

Any Assets and liabilities of a corporation that are being utilized in a joint venture must be included along with the corporation's other Assets and liabilities when calculating its Taxable Paid-up Capital.

Special rules and rates apply to Non-Resident corporations (s.63, s.64 and s.69(3)).

Paid-up Capital of Non-resident: Paid-up capital employed in Canada of a non-resident subject to tax by virtue of s.2(2)(a) or 2(2)(b), and whose **business is not carried on solely in Canada** is deemed to be the **greater** of (1) taxable Income in Canada divided by 8 percent or (2) total assets in Canada minus certain indebtedness in accordance with the provisions of s.63(1)(a) (Int.B. 3010).

Paid-up Capital

Paid-up capital stock (Int.B. 3012R and 3015R)	+	350	5,035,066
Retained earnings (if deficit, deduct) (Int.B. 3012R)	±	351	2,456,145
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	+	352	
Loans and advances *(Attach schedule)* (Int.B. 3013R)	+	353	5,256,649
Bank loans (Int.B. 3013R)	+	354	
Bankers acceptances (Int.B. 3013R)	+	355	
Bonds and debentures payable (Int.B. 3013R)	+	356	
Mortgages payable (Int.B. 3013R)	+	357	
Lien notes payable (Int.B. 3013R)	+	358	
Deferred credits (including income tax reserves, and deferred revenue where it would also be included in paid-up capital for the purposes of the large corporations tax) (Int.B. 3013R)	+	359	
Contingent, investment, inventory and similar reserves (Int.B. 3012R)	+	360	
Other reserves not allowed as deductions for income tax purposes *(Attach schedule)* (Int.B. 3012R)	+	361	4,338,105
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	+	362	
Subtotal	=	370	17,085,965
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012R)	–	371	
Deductible R & D expenditures and ONTTI costs deferred for income tax if not already deducted for book purposes (Int.B. 3015R)	–	372	
Total Paid-up Capital	=	380	17,085,965
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	17,085,965

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	1
Loans and advances to unrelated corporations	+	405	21,096
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	21,097

continued on Page 10

Total Assets (Int.B. 3015R) *DOLLARS ONLY*

Total Assets per balance sheet	+	420	15,922,396
Mortgages or other liabilities deducted from assets	+	421	
Share of partnership(s)/joint venture(s) total assets *(Attach schedule)*	+	422	
Subtract: Investment in partnership(s)/joint venture(s)	–	423	
Total Assets as adjusted	=	430	15,922,396
Amounts in 360 and 361 (if deducted from assets)	+	440	4,338,105
Subtract: Amounts in 371, 372 and 381	–	441	
Subtract: Appraisal surplus if booked	–	442	
Add or Subtract: Other adjustments (specify on an attached schedule)	±	443	
Total Assets	=	450	20,260,501

Investment Allowance (410 ÷ 450) x 390 Not to exceed 410 = 460 17,791

Taxable Capital 390 – 460 = 470 17,068,174

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue) 480 11,824,638

Total Assets (as adjusted) From 430 15,922,396

Calculation of Capital Tax for all Corporations except Financial Institutions

Note: *This version (2006) of the CT23 may only be used for a taxation year that commenced after December 31, 2003.*

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 below, 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

Calculation of Taxable Capital Deduction (TCD)

Number of Days in Taxation Year

5,000,000	x	Days before Jan. 1, 2005: 35	÷	Total Days: 73	365	= +	500	
7,500,000	x	Days after Dec. 31, 2004 and before Jan. 1, 2006: 36	÷	Total Days: 73	365	= +	501	
10,000,000	x	Days after Dec. 31, 2005 and before Jan. 1, 2007: 37 365	÷	Total Days: 73	365	= +	502	10,000,000

Taxable Capital Deduction (TCD) 500 + 501 + 502 = 503 10,000,000

SECTION C

This section applies if the corporation is **not** a member of an associated group and/or partnership.

C1. If 430 and 480 on page 10 are both $3,000,000 or less, enter NIL in 550 on page 12 and complete the return from that point.

C2. If Taxable Capital in 470 is **equal to or less than the TCD** in 503, enter NIL in 550 on page 12 and complete the return from that point.

C3. If Taxable Capital in 470 **exceeds the TCD** in 503, complete the following calculation and transfer the amount from 523 to 543 on page 12, and complete the return from that point.

+	From 470	17,068,174										
–	From 503	10,000,000										
=	471	7,068,174	x	From 30	100.0000 % Ontario Allocation	x	0.3 %	x	555 365 / 365 (366 if leap year) Days in taxation year	= +	523	21,205

If floating taxation year, refer to Guide.

Transfer to 543 *on page 12 and complete the return from that point*

continued on Page 11

Capital Tax Calculation *continued from Page 10*

SECTION D

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either 509 or 524 and complete this section before you can calculate your Capital Tax Calculation under either Section E or Section F.

D1. ☐ 509 (X if applicable)

All corporations that you are associated with do **not** have a permanent establishment in Canada.

If Taxable Capital 470 on page 10 is equal to or less than the TCD 503 on page 10, enter NIL in 550 on page 12 and complete the return from that point.

If Taxable Capital 470 on page 10 exceeds the TCD 503 on page 10, proceed to **Section E**, enter the TCD amount in 542 in Section E, and complete Section E and the return from that point.

D2. ☐ 524 (X if applicable)

One or more of the corporations that you are associated with **maintains** a permanent establishment in Canada.

You and your associated group may continue to allocate the TCD by completing the Calculation below. Or, the associated group **may file an election** under subsection 69(2.1) of the *Corporations Tax Act*, whereby total assets are used to allocate the TCD among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as **Net Deduction**) of the capital tax effect relating to the TCD to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group.

The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year.

In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

Calculation

Do **not** complete this calculation if ss.69(2.1) election is filed

Taxable Capital From 470 on page 10 - + From 470 _____ •

Determine aggregate taxable capital of an associated group (excluding financial institutions and corporations exempt from capital tax) and/or partnership having a permanent establishment in Canada

Names of associated corporations (excluding Financial Institutions and corporations exempt from Capital Tax) having a permanent establishment in Canada *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Taxable Capital
			+ 531 _____ •
			+ 532 _____ •
			+ 533 _____ •
Aggregate Taxable Capital 470 + 531 + 532 + 533 , etc. - - - - - - - - - - - - - - - - - -			= 540 _____ •

If 540 above is equal to or less than the TCD 503 on page 10, the corporation's Capital Tax for the taxation year, is NIL.

Enter NIL in 523 in section E on page 12, 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 on page 12.

From 470 _____ • ÷ From 540 _____ • x From 503 _____ • = 541 _____ •

Transfer to 542 in Section E on page 12

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** on page 12.

continued on Page 12

DOLLARS ONLY

Capital Tax Calculation *continued from Page 11*

SECTION E

This section applies if the corporation **is** a member of an associated group and/or partnership whose total **aggregate** Taxable Capital [540] on page 11 exceeds the TCD [503] on page 10.

Complete the following calculation and transfer the amount from [523] to [543], and complete the return from that point.

\+ From [470] _____ .
– [542] _____ .
= [471] _____ . x From [30] 100.0000 % (Ontario Allocation) x 0.3 % x [555] 365 / * 365 (366 if leap year) = + [523] _____ . **Total Capital Tax for the taxation year**

Transfer to [543] *and complete the return from that point*

SECTION F

This section applies if a corporation is a member of an associated group and the associated group has filed a ss.69(2.1) election

\+ From [470] _____ . x From [30] 100.0000 % (Ontario Allocation) x 0.3 % = + [561] _____ .

– Capital tax deduction from [995] relating to **your corporation's** Capital Tax deduction, on Schedule 591 – From [995] _____ .
= [562] _____ .

Total Capital Tax for the taxation year

Capital Tax [562] _____ . x [555] 365 / * 365 (366 if leap year) = [563] _____ .

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] 21,205 .
Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)* – [546] _____ .

Capital Tax [543] – [546] *(amount cannot be negative)* = [550] 21,205 .
Transfer to Page 17

continued on Page 13

Capital Tax *continued from Page 12*

Calculation of Capital Tax for Financial Institutions

1.1 Credit Unions only

For taxation years commencing **after May 4, 1999** enter NIL in [550] on page 12, and complete the return from that point.

1.2 Other than Credit Unions

(Retain details of calculations for amounts in boxes [565] and [570]. Do not submit with this tax return.)

[565] _____ • x 0.6 % x From [30] 100.0000 % x [555] 365 ÷ * 365 (366 if leap year) = + [569] _____ •

Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1

Ontario Allocation

Days in taxation year

[570] _____ • x [571] _____ x From [30] 100.0000 % x [555] 365 ÷ * 365 (366 if leap year) = + [574] _____ •

Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount

Capital Tax Rate *(Refer to Guide)*

Ontario Allocation

Days in taxation year

Capital Tax for Financial Institutions – other than Credit Unions (before Section 2) [569] + [574] - - = [575] _____ •

** If floating taxation year, refer to Guide.*

2. Small Business Investment Tax Credit

(Retain details of eligible investment calculation and, if claiming an investment in CSBIF, retain the original letter approving the credit issued in accordance with the Community Small Business Investment Fund Act. Do not submit with this tax return.)

Allowable Credit for Eligible Investments - - -

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 ± 600 593,384 •
Transfer to Page 15

Add:

Federal capital cost allowance	+ 601	710,022 •
Federal cumulative eligible capital deduction	+ 602	•
Ontario taxable capital gain	+ 603	•
Federal non-allowable reserves. Balance beginning of year	+ 604	541,226 •
Federal allowable reserves. Balance end of year	+ 605	•
Ontario non-allowable reserves. Balance end of year	+ 606	239,654 •
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	•
All Crown charges, royalties, rentals, etc. deducted for Federal purposes *(Refer to Guide)*	+ 617	•

Management fees, rents, royalties and similar payments to non-arms' length non-residents ▼

Number of Days in Taxation Year

612 • x 5 / 12.5 x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 33 ÷ Total Days: 73 365) =+ 633 •

612 • x 5 / 14 x (Days after Dec. 31, 2003: 34 365 ÷ Total Days: 73 365) =+ 634 •

Total add-back amount for Management fees, etc. 633 + 634 = • ▶ + 613 •

Federal Scientific Research Expenses claimed in year from line 460 of fed. form T661 excluding any negative amount in 473 from Ont. CT23 Schedule 161 + 615 •

Add any negative amount in 473 from Ont. CT23 Schedule 161 + 616 •

Federal allowable business investment loss + 620 •

Total of other items not allowed by Ontario but allowed federally *(Attach schedule)* + 614 •

Total of Additions 601 to 611 + 617 + 613 + 615 + 616 + 620 + 614 = 1,490,902 • ▶ 640 1,490,902 •
Transfer to Page 15

Deduct:

Ontario capital cost allowance (excludes amounts deducted under 675)	+ 650	710,022 •
Ontario cumulative eligible capital deduction	+ 651	•
Federal taxable capital gain	+ 652	•
Ontario non-allowable reserves. Balance beginning of year	+ 653	541,226 •
Ontario allowable reserves. Balance end of year	+ 654	•
Federal non-allowable reserves. Balance end of year	+ 655	239,654 •
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 1,490,902 •
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 ± 600 593,384 •

Total of Additions on page 14 - From = 640 1,490,902 •

Sub Total of deductions on page 14 - From = 681 1,490,902 •

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up
(***Applies*** only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

Capital Cost Allowance (Ontario) (CCA) on prescribed qualifying intellectual property deducted in the current taxation year - - - 662 •

ONTTI Gross-up deduction calculation:

Gross-up of CCA

From 662 • x 100 / From 30 100.0000 Ontario Allocation — From 662 • = 663 •

Workplace Child Care Tax Incentive (WCCT)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: 665 • x 30 % x 100 / From 30 100.0000 Ontario allocation = 666 •

Workplace Accessibility Tax Incentive (WATI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: 667 • x 100 % x 100 / From 30 100.0000 Ontario allocation = 668 •

Number of Employees accommodated 669

Ontario School Bus Safety Tax Incentive (OSBSTI)
(***Applies*** to the eligible acquisition of school buses purchased after May 4, 1999 and before January 1, 2006.) *(Refer to Guide)*

Qualifying expenditures: 670 • x 30 % x 100 / From 30 100.0000 Ontario allocation = 671 •

Educational Technology Tax Incentive (ETTI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: 672 • x 15 % x 100 / From 30 100.0000 Ontario allocation = 673 •

Ontario allowable business investment loss - - - - - - - - - - - - - - - + 678 •

Ontario Scientific Research Expenses claimed in year in 477 from Ont. CT23 Schedule 161 + 679 •

Amount added to income federally for an amount that was negative on federal form T661, line 454 or 455 (if filed after June 30, 2003) - - - - - - - - - + 677 •

Total of other deductions allowed by Ontario *(Attach schedule)* - - - - - - - - + 664 •

Total of Deductions 681 + 663 + 666 + 668 + 671 + 673 + 678 + 679 + 677 + 664 = 1,490,902 • ▶ 680 1,490,902 •

Net income (loss) for Ontario Purposes 600 + 640 − 680 - - - - - - - - - - - - - - - - - = 690 593,384 •

Transfer to Page 4

Continuity of Losses Carried Forward

DOLLARS ONLY

		Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year		700 (2)	710 (2)	720 (2)	730	740	750
Add:	Current year's losses (7)	701	711	721	731	741	751
	Losses from predecessor corporations (3)	702	712	722	732		752
Subtotal		703	713	723	733	743	753
Subtract:	Utilized during the year to reduce taxable income	704 (2)	715 (2) (4)	724 (2)	734 (2) (4)	744 (4)	754 (4)
	Expired during the year	705		725	735	745	
	Carried back to prior years to reduce taxable income (5)	706 (2) to Page 17	716 (2) to Page 17	726 (2) to Page 17	736 (2) to Page 17	746	
Subtotal		707	717	727	737	747	757
Balance at End of Year		709 (8)	719	729	739	749	759

Analysis of Balance at End of Year by Year of Origin

	Year of Origin (oldest year first) year month day	Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800	9th preceding taxation year 1997-12-31	817 (9)	860 (9)		850	870
801	8th preceding taxation year 1998-12-31	818 (9)	861 (9)		851	871
802	7th preceding taxation year 1999-12-31	819 (9)	862 (9)		852	872
803	6th preceding taxation year 2000-12-31	820	830	840	853	873
804	5th preceding taxation year 2001-12-31	821	831	841	854	874
805	4th preceding taxation year 2002-12-31	822	832	842	855	875
806	3rd preceding taxation year 2003-12-31	823	833	843	856	876
807	2nd preceding taxation year 2004-12-31	824	834	844	857	877
808	1st preceding taxation year 2005-12-31	825	835	845	858	878
809	Current taxation year 2006-12-31	826	836	846	859	879
Total		829	839	849	869	889

Notes:

(1) Non-capital losses include allowable business investment losses, fed.s.111(8)(b), as made applicable by s.34.

(2) Where acquisition of control of the corporation has occurred, the utilization of losses can be restricted. See fed.s.111(4) through 111(5.5), as made applicable by s.34.

(3) Includes losses on amalgamation (fed.s.87(2.1) and s.87(2.11)) and/or wind-up (fed.s.88(1.1) and 88(1.2)), as made applicable by s.34.

(4) To the extent of applicable gains/income/at-risk amount only.

(5) Generally a three year carry-back applies. See fed.s.111(1) and fed.s.41(2)(b), as made applicable by s.34.

(6) Where a limited partner has limited partnership losses, attach loss calculations for each partnership.

(7) Include amount from 11 if taxable income is adjusted to claim unused foreign tax credit for federal purposes.

(8) Amount in 709 must equal total of 829 + 839.

(9) Include non-capital losses incurred in taxation years ending after March 22, 2004.

Request for Loss Carry-Back (s.80(16))

Applies to corporations requesting a reassessment of the return of one or more previous taxation years under s.80(16) with respect to one or more types of losses carried back.

- If, after applying a loss carry-back to one or more previous years, there is a balance of loss available to carry forward to a future year, it is the corporation's responsibility to claim such a balance for those years following the year of loss within the limitations of fed.s.111, as made applicable by s.34.
- Where control of a corporation has been acquired by a person or group of persons, certain restrictions apply to the carry-forward and carry-back provisions of losses under fed.s.111(4) through 111(5.5), as made applicable by s.34.
- Refunds arising from the loss carry-back adjustment may be applied by the Minister of Finance to amounts owing under **any Act administered by the Ministry of Finance**.
- Any late filing penalty applicable to the return for which the loss is being applied will not be reduced by the loss carry-back.
- The application of a loss carry-back will be available for interest calculation purposes on the day that is the latest of the following:
  1) the first day of the taxation year after the loss year,
  2) the day on which the corporation's return for the loss year is delivered to the Minister, or
  3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
- If a loss is being carried back to a **predecessor corporation**, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses

	Predecessor Ontario Corporation's Tax Account No. (MOF)	Taxation Year Ending year month day	Non-Capital Losses	Total Capital Losses	Farm Losses	Restricted Farm Losses
Total amount of loss			910	920	930	940
Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income						
i) 3rd preceding	901	2003-12-31	911	921	931	941
ii) 2nd preceding	902	2004-12-31	912	922	932	942
iii) 1st preceding	903	2005-12-31	913	923	933	943
Total loss to be carried back			From 706	From 716	From 726	From 736
Balance of loss available for carry-forward			919	929	939	949

Summary

Income Tax	+ From 230 or 320		42,868
Corporate Minimum Tax	+ From 280		
Capital Tax	+ From 550		21,205
Premium Tax	+ From 590		
Total Tax Payable	=	950	64,073
Subtract: Payments	–	960	175,806
Capital Gains Refund (s.48)	–	965	
Qualifying Environmental Trust Tax Credit *(Refer to Guide)*	–	985	
Specified Tax Credits *(Refer to Guide)*	–	955	
Other, specify Federal PIL	–		-102,116
Balance	=	970	-9,617
If payment due	Enclosed *	990	
If overpayment: Refund *(Refer to Guide)*	=	975	9,617
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)*

FLORENCE THIESSEN

Title

VICE-PRESIDENT-TREASURER

Full Residence Address

Signature	Date
	2007-05-21

Note: Section 76 of the *Corporations Tax Act* provides penalties for making false or misleading statements or omissions.

Attached Schedule with Total

Other reserves not allowed as deductions for income tax purposes (Attach schedule) (Int.B. 3012R)

Title Other reserves not allowed as deductions for income tax purposes (Attach

Description	Amount
Ontario schedule 8 UCC Ending balance	11,107,351 00
NBV	-7,008,900 00
Post-employment benefits	84,988 00
Regulatory liabilities,net	154,666 00
Total	4,338,105 00

Attached Schedule with Total

Loans and advances to unrelated corporations

Title Loans and advances to unrelated corporations

Description	Amount
prepaid expenses	21,096 00
Total	21,096 00

Corporate Minimum Tax (CMT)

CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	2006-12-31

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	152,263
Subtract (to the extent reflected in net income/loss):					
Provision for recovery of income taxes / benefit of current income taxes		+ 2101			
Provision for deferred income taxes (credits) / benefit of future income taxes		+ 2102			
Equity income from corporations		+ 2103			
Share of partnership(s)/joint venture(s) income		+ 2104			
Dividends received/receivable deductible under fed.s.112		+ 2105	369		
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		=	369	– 2110	369
Add (to extent reflected in net income/loss):					
Provision for current taxes / cost of current income taxes		+ 2111	246,816		
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		=	246,816	+ 2116	246,816
Add/Subtract:					
Amounts relating to s.57.9 election/regulations for disposals etc. of property for current/prior years					
** Fed.s.85		+ 2117		or – 2118	
** Fed.s.85.1		+ 2119		or – 2120	
** Fed.s.97		+ 2121		or – 2122	
** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years		+ 2123		or – 2124	
** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/prior years		+ 2125		or – 2126	
** Amounts relating to s.57.10 election/ regulations for replacement re fed.s13(4), 14(6) and 44 for current/prior years		+ 2127		or – 2128	
Interest allowable under ss.20(1)(c) or (d) of ITA to the extent not otherwise deducted in determining CMT adjusted net income				– 2150	
Subtotal (Additions)		=			+ 2129
Subtotal (Subtractions)		=			– 2130
** Other adjustments					± 2131
Subtotal ± 2100 – 2110 + 2116 + 2129 – 2130 ± 2131				= 2132	398,710
** 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	398,710
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	398,710

Transfer to CMT Base on Page 8 of the CT23 or Page 6 of the CT8

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	2006-12-31

Part 2: Continuity of CMT Losses Carried Forward

Balance at Beginning of year NOTES (1), (2)				+ 2201	
Add: Current year's losses		+ 2202			
Losses from predecessor corporations on amalgamation NOTE (3)		+ 2203			
Losses from predecessor corporations on wind-up NOTE (3)		+ 2204			
Amalgamation (X) 2205 ☐ Yes Wind-up (X) 2206 ☐ Yes					
Subtotal	=		▶	+ 2207	
Adjustments (attach schedule)				± 2208	
CMT losses available 2201 + 2207 ± 2208				= 2209	
Subtract: Pre-1994 loss utilized during the year to reduce adjusted net income		+ 2210			
Other eligible losses utilized during the year to reduce adjusted net income NOTE (4)		+ 2211			
Losses expired during the year		+ 2212			
Subtotal	=		▶	− 2213	
Balances at End of Year NOTE (5) 2209 − 2213				= 2214	

Notes:

(1) Pre-1994 CMT loss (see s.57.1(1)) should be included in the balance at beginning of the year. Attach schedule showing computation of pre-1994 CMT loss.

(2) Where acquisition of control of the corporation has occured, 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 1997-12-31	2260	2280
2241	8th preceding taxation year 1998-12-31	2261	2281
2242	7th preceding taxation year 1999-12-31	2262	2282
2243	6th preceding taxation year 2000-12-31	2263	2283
2244	5th preceding taxation year 2001-12-31	2264	2284
2245	4th preceding taxation year 2002-12-31	2265	2285
2246	3rd preceding taxation year 2003-12-31	2266	2286
2247	2nd preceding taxation year 2004-12-31	2267	2287
2248	1st preceding taxation year 2005-12-31	2268	2288
2249	Current taxation year 2006-12-31	2269	2289
Totals		2270	2290

The sum of amounts 2270 + 2290 ***must equal amount in*** 2214.

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	2006-12-31

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

Balances 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 1997-12-31	2360	2380
2341	8th preceding taxation year 1998-12-31	2361	2381
2342	7th preceding taxation year 1999-12-31	2362	2382
2343	6th preceding taxation year 2000-12-31	2363	2383
2344	5th preceding taxation year 2001-12-31	2364	2384
2345	4th preceding taxation year 2002-12-31	2365	2385
2346	3rd preceding taxation year 2003-12-31	2366	2386
2347	2nd preceding taxation year 2004-12-31	2367	2387
2348	1st preceding taxation year 2005-12-31	2368	2388
2349	Current taxation year 2006-12-31	2369	2389
Totals		2370	2390

The sum of amounts 2370 + 2390 ***must equal amount in*** 2336 .

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	2006-12-31

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	1996-12-31					
9th Prior Year	1997-12-31					
8th Prior Year	1998-12-31					
7th Prior Year	1999-12-31					
6th Prior Year	2000-12-31					
5th Prior Year	2001-12-31					
4th Prior Year	2002-12-31					
3rd Prior Year	2003-12-31					
2nd Prior Year	2004-12-31					
1st Prior Year	2005-12-31					
	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
1996-12-31						
1997-12-31						
1998-12-31						
1999-12-31						
2000-12-31						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	2006-12-31

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
1996-12-31						
1997-12-31						
1998-12-31						
1999-12-31						
2000-12-31						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	2006-12-31

CMT Credit Carryovers Workchart

Filing Corporation

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1996-12-31					
9th Prior Year	1997-12-31					
8th Prior Year	1998-12-31					
7th Prior Year	1999-12-31					
6th Prior Year	2000-12-31					
5th Prior Year	2001-12-31					
4th Prior Year	2002-12-31					
3rd Prior Year	2003-12-31					
2nd Prior Year	2004-12-31					
1st Prior Year	2005-12-31					
	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
1996-12-31						
1997-12-31						
1998-12-31						
1999-12-31						
2000-12-31						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
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
1996-12-31						
1997-12-31						
1998-12-31						
1999-12-31						
2000-12-31						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
Total						

Ontario

Ministry of Finance
Corporations Tax Branch
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Paid-Up Capital: Loans and Advances

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	2006-12-31

Loans or Advances Credited or Advanced to Corporation
(includes accounts payable to related parties outstanding at the taxation year end for 120 days or more, and accounts payable to non-related parties outstanding for 365 days or more at the taxation year end)

Current portion of customer deposits	+	209,896
Due to shareholder	+	
Customer deposits	+	
Note payable	+	5,046,753
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
Total *Transfer to* 353 *of the CT23*	=	5,256,649

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33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Ontario Charitable Donations and Gifts

Schedule 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	2006-12-31

- 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	+	81,225 E		
Subtotal D + E	=	81,225	▶	81,225 F
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)			−	G
Total donations available **C + F – G**			=	81,225 H
Deduct: Amount applied against taxable income (amount **U**, Part 2)			−	81,225 U
Charitable donations closing balance			=	I

Part 2 – Maximum Deduction Calculation for Donations

Ontario net income for tax purposes multiplied by 75%			=	445,038 J
Note: *For credit unions the Ontario net income for tax purposes is the amount before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.*				
Ontario taxable capital gains arising in respect of gifts of capital property	+	K		
Ontario taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01) ITA	+	L		

Add the lesser of:

1. The amount of the recapture of capital cost allowance in respect of charitable gifts — M
2. **The lesser of:**
   - 2a. Proceeds of dispositions less outlays and expenses — N
   - 2b. The capital cost — O
   - The lesser of **N** and **O** ▶ P

The lesser of **M** and **P** ▶	+	Q		
Subtotal K + L + Q	=	R		
25% X R			=	S
Maximum deduction allowable J + S			=	445,038 T
Claim for charitable donations (not exceeding the lesser of **H** from Part 1, **T** and net income for tax purposes)				81,225 U

Enter in 1 *of the CT23*

Ontario Charitable Donations and Gifts

Schedule 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	2006-12-31

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 . . . . . 512,159 V

2. **Lesser of:**

   2a. Ontario Net Income for the taxation year . . . . . 593,384 W

   2b. Gifts made in the taxation year or any of the five preceding taxation years to Her Majesty in Right of Ontario, an Ontario Crown Agency or an Ontario Crown Foundation X

   The lesser of **W** and **X** . . . . . Y

Maximum deduction allowable the lesser of **V** and **Y** . . . . . Z

Transfer to 2 *of the CT23*

Part 5 – Gifts to Canada or a province other than Ontario

Gifts to Canada or a province other than Ontario at the end of the preceding year . . . . . +

Deduct: Gifts to Canada or a province other than Ontario expired after five taxation years . . . . . −

Gifts to Canada or a province other than Ontario at the beginning of the taxation year . . . . . =

Add: Gifts to Canada or a province other than Ontario transferred on amalgamation or wind-up of a subsidiary . . . . . +

Total current year Gifts to Canada or a province other than Ontario *(Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date.)* . . . . . +

Subtotal . . . . . =

Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004) . . . . . −

Total gifts to Canada or a province other than Ontario available . . . . . =

Deduct: Amount applied against taxable income . . . . . −

Gifts to Canada or a province other than Ontario closing balance . . . . . =

Ontario Charitable Donations and Gifts

Schedule 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	2006-12-31

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
2005-12-31					
2004-12-31					
2003-12-31					
2002-12-31					
2001-12-31					
2000-12-31					
Totals					

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Corporations Tax Branch
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Ontario Capital Cost Allowance
Schedule 8

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	2006-12-31

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	10,170,846	1,500		0	10,172,346	750	10,171,596	4	0	0	406,864	9,765,482
8	787,467	326,527		0	1,113,994	163,264	950,730	20	0	0	190,146	923,848
10	161,020	291,460		0	452,480	145,730	306,750	30	0	0	92,025	360,455
10	35,011			0	35,011		35,011	30	0	0	10,503	24,508
17	13,016			0	13,016		13,016	8	0	0	1,041	11,975
45	3,865	20,459		0	24,324	10,230	14,094	45	0	0	6,342	17,982
12		6,202		0	6,202	3,101	3,101	100	0	0	3,101	3,101
Totals	11,171,225	646,148			11,817,373	323,075	11,494,298				710,022	11,107,351

Enter in boxes 650 . . . . 650 . . . . 650 on the CT23.

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule. See Regulation 1100(2) and (2.2) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

Ontario

Ministry of Finance
Corporations Tax Branch
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Ontario Continuity of Reserves
Schedule 13

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	2006-12-31

For use by a corporation to provide a continuity of all reserves claimed which are allowed for tax purposes.

Part 1 – Capital gains reserves

	Description of property	Ontario balance at the beginning of the year $	Transfer on amalgamation or wind-up of subsidiary $	Add	Deduct	Ontario balance at the end of the year $
1						
	Totals	A	B			C

The total capital gains reserve at the beginning of the taxation year **A** plus the total capital gains reserve transfer on amalgamation or wind-up of subsidiary **B**, should be entered on Schedule 6; and the total capital gains reserve at the end of the taxation year **C**, should also be entered on Schedule 6.

Part 2 – Other reserves

Description	Ontario balance at the beginning of the year $	Transfer on amalgamation or wind-up of subsidiary $	Add	Deduct	Ontario balance at the end of the year $
Reserve for doubtful debts					
Reserve for undelivered goods and services not rendered					
Reserve for prepaid rent					
Reserve for December 31, 1995 income					
Reserve for refundable containers					
Reserve for unpaid amounts					
Other tax reserves					
Totals	D	E			F

The amount from **D** plus the amount from **E** should be entered in [607] of the CT23.

The amount from **F** should be entered in [654] of the CT23.

Part 3 – Continuity of non-deductible reserves

Reserve	Ontario opening balance	Transfers	Ontario additions	Ontario deductions	Other adjustments	Ontario closing balance
Recoveries of regulatory assets	286,757			546,755		-259,998
Settlement variance	169,696		244,968			414,664
Post-employment benefits	84,773		215			84,988
Reserves from Part 2						
Totals	541,226		245,183	546,755		239,654

Enter in box [653] *of the CT23* — *Enter in box* [606] *of the CT23*

Canada Revenue Agency / Agence 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 *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing. For more information on how to complete the return, see the *T2 Corporation – Income Tax Guide* (T4012).

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 on when and how to file T2 returns, refer to the Guide under the heading "Before you start."

055 Do not use this area

Identification

Business Number (BN) 001 86547 0769 RC0001

Corporation's name

002 CENTRE WELLINGTON HYDRO LTD.

Has the corporation changed its name since the last time we were notified? 003 1 Yes ☐ 2 No ☒

If *Yes*, do you have a copy of the articles of amendment? . . . 004 1 Yes ☐ 2 No ☐

Address of head office

Has this address changed since the last time we were notified? . . . . . 010 1 Yes ☐ 2 No ☒

(If *Yes*, complete lines 011 to 018)

011 730 GARTSHORE STREET

012 PO BOX 217

City	Province, territory, or state
015 FERGUS	016 ON
Country (other than Canada)	**Postal code/Zip code**
017	018 N1M 2W8

Mailing address (if different from head office address)

Has this address changed since the last time we were notified? . . . . . 020 1 Yes ☐ 2 No ☒

(If *Yes*, complete lines 021 to 028)

021 c/o

022 730 GARTSHORE STREET

023 PO BOX 217

City	Province, territory, or state
025 FERGUS	026 ON
Country (other than Canada)	**Postal code/Zip code**
027	028 N1M 2W8

Location of books and records

Has the location of books and records changed since the last time we were notified? . . . . . 030 1 Yes ☐ 2 No ☒

(If *Yes*, complete lines 031 to 038)

031 730 GARTSHORE STREET

032 PO BOX 217

City	Province,territory, or state
035 FERGUS	036 ON
Country (other than Canada)	**Postal code/Zip code**
037	038 N1M 2W8

040 Type of corporation at the end of the taxation year

1 ☒ Canadian-controlled private corporation (CCPC)
2 ☐ Other private corporation
3 ☐ Public corporation
4 ☐ Corporation controlled by a public corporation
5 ☐ Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . . 043 _____ YYYY MM DD

To which tax year does this return apply?

060 Tax year start 2006-01-01 YYYY MM DD

061 Tax year end 2006-12-31 YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? 063 1 Yes ☐ 2 No ☒

If *Yes*, provide the date control was acquired . . . . . 065 _____ YYYY MM DD

Is the 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 windup 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 Canadian-controlled private corporation?	160		23
Is the corporation an associated Canadian-controlled private corporation that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered *Yes* to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; or gifts of cultural or ecological property?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207	X	7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210		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
Is the corporation a non-resident-owned investment corporation claiming an allowable refund?	226		26*
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		33/34/35
Is the corporation a member of a related group with one or more members subject to gross Part I.3 tax?	236		36
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax?	255		92 *

*** We do not print this schedule.**

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174

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 ELECTRICITY	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 GIFI.	300		593,384	A
Deduct: Charitable donations from Schedule 2	311	81,225		
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320	369		
Part VI.1 tax deduction from Schedule 43 *	325			
Non-capital losses of preceding tax years from Schedule 4	331			
Net capital losses of preceding tax years from Schedule 4	332			
Restricted farm losses of preceding tax years from Schedule 4	333			
Farm losses of preceding tax years from Schedule 4	334			
Limited partnership losses of preceding 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		81,594	▶ 81,594	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			511,790	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		511,790	
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)			511,790	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 . . . . . 400 593,015 A

Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 3 times the amount on line 636**, and **minus** any amount that, because of federal law, is exempt form Part I tax . . . . . 405 511,790 B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

250,000 x (Number of days in the tax year in 2004 / Number of days in the tax year) = 1

300,000 x (Number of days in the tax year in 2005 and in 2006 / Number of days in the tax year) = 300,000 2

400,000 x (Number of days in the tax year after 2006 / Number of days in the tax year) = 3

Add amounts at lines 1, 2, and 3 300,000 4

Business limit (see notes 1 and 2 below) . . . . . 410 300,000 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 300,000 x 415 *** 6,577 / 11,250 D = ... 175,387 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . 425 124,613 F

Small business deduction

Whichever amount is the least A, B, C or F 124,613 G1

Amount G1 124,613 x (Number of days in the tax year before 2008 / Number of days in the tax year) 365/365 x 16.00 % = 19,938 G2

Amount G1 124,613 x (Number of days in the tax year in 2008 / Number of days in the tax year) /365 x 16.50 % = G3

Amount G1 124,613 x (Number of days in the tax year after 2008 / Number of days in the tax year) /365 x 17.00 % = G4

Small business deduction – total of amounts G2, G3, and G4 . . . . . 430 19,938 G
(enter amount G on line 9)

* 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**

- The amount to be entered at line 415 is the total taxable capital employed in Canada **minus** $10,000,000 x 0.225%, calculated on Schedule 33, *Part I.3 Tax On Large Corporations*, Schedule 34, *Part I.3 Tax On Financial Institutions* **or** Schedule 35, *Part I.3 Tax On Large Insurance Companies*.
- If the corporation is not associated with any corporations in both the current and the preceding tax years, use the applicable schedule for the **prior** year. (Amount **P** in Part 6 of Schedule 33; Amount **O** in Part 6 of Schedule 34; Amount **DD** in Part 6 of Schedule 35)
- If the corporation is not associated with any corporations in the current tax year, but was associated in the preceding tax year, use the applicable schedule for the **current** year.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Accelerated tax reduction

Canadian-controlled private corporations throughout the taxation year that claimed the small business deduction

Reduced business limit (amount from line 425)	124,613	x	300,000 / line 4 above	=	124,613 A
Net active business income (amount from line 400) *					593,015 B
Taxable income from line 360 **minus** 3 times the amount at line 636** on, and **minus** any amount that, because of federal law, is exempt from Part I Tax	511,790 C				
Deduct:					
Aggregate investment income (amount from line 440)	D				
Amount C **minus** amount D (if negative, enter "0")	511,790 ▶				511,790 E
Amount A, B, or E above, whichever is less					124,613 F
Amount Z from Part 9 of Schedule 27	x 100 / 7 =	G			
Amount QQ from Part 13 of Schedule 27	H				
Taxable resource income (amount from line 435)	I				
Amount used to calculate the credit union deduction (amount E in Part 3 of Schedule 17)	J				
Amount on line 400, 405, 410, or 425 of the small business deduction, whichever is less	124,613 K				
Total of amounts G, H, I, J, and K	124,613 ▶				124,613 L
Amount F **minus** amount L (if negative, enter "0")					M
Accelerated tax reduction – 7.00 % of amount M (enter amount N on line 637)					N

* If the amount at line 450 of Schedule 7 is positive, members of partnerships need to use Schedule 70 to calculate net active business income.

** Calculate the amount of foreign business income tax credit deductible at line 636 without reference to the corporate tax reductions under section 123.4.

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)] 435 A

Amount A	x	Number of days in the tax year in 2004 / Number of days in the tax year	365	x 2 % =		B
Amount A	x	Number of days in the tax year in 2005 / Number of days in the tax year	365	x 3 % =		C
Amount A	x	Number of days in the tax year in 2006 / Number of days in the tax year	365 / 365	x 5 % =		D
Amount A	x	Number of days in the tax year after 2006 / Number of days in the tax year	365	x 7 % =		E

Resource deduction – total of amounts B, C, D, and E (enter amount F on line 10) 438 F

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360					511,790 A	
Amount Z1 from Part 9 of Schedule 27	B					
Amount QQ from Part 13 of Schedule 27	C					
Taxable resource income from line 435 above	D					
Amount used to calculate the credit union deduction (amount E in Part 3 of Schedule 17)	E					
Amount on line 400, 405, 410, or 425, whichever is the least	124,613 F					
Aggregate investment income from line 440	G					
Amount used to calculate the accelerated tax reduction (amount M)	H					
Total of amounts B, C, D, E, F, G, and H	124,613 ▶				124,613 I	
Amount A **minus** amount I (if negative, enter "0")					387,177 J	
Amount J	387,177 x	Number of days in the tax year before 2008 / Number of days in the tax year	365 / 365	x 7 % =	27,102	K1
Amount J	387,177 x	Number of days in the tax year in 2008 / Number of days in the tax year	365	x 7.5 % =		K2
Amount J	387,177 x	Number of days in the tax year in 2009 / Number of days in the tax year	365	x 8 % =		K3
Amount J	387,177 x	Number of days in the tax year after 2009 / Number of days in the tax year	365	x 9 % =		K4

General tax reduction for Canadian-controlled private corporations – total of amounts K1, K2, K3, and K4 (enter amount K on line 638) 27,102 K

General tax reduction

Corporations other than a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation; and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the full tax rate of 38% (eg. deposit insurance company).

Taxable income from line 360						L
Amount Z1 from Part 9 of Schedule 27					M	
Amount QQ from Part 13 of Schedule 27					N	
Taxable resource income from line 435 above					O	
Amount used to calculate the credit union deduction (amount E in Part 3 of Schedule 17)					P	
Total of amounts M, N, O, and P				▶		Q
Amount L **minus** amount Q (if negative, enter "0")						R
Amount R	x	Number of days in the tax year before 2008 / Number of days in the tax year	365 / 365	x 7 % =		S1
Amount R	x	Number of days in the tax year in 2008 / Number of days in the tax year	/ 365	x 7.5 % =		S2
Amount R	x	Number of days in the tax year in 2009 / Number of days in the tax year	/ 365	x 8 % =		S3
Amount R	x	Number of days in the tax year after 2009 / Number of days in the tax year	/ 365	x 9 % =		S4
General tax reduction – total of amounts S1, S2, S3, and S4 (enter amount S on line 639)						S

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income (amount O from Part 1 of Schedule 7)	440		x 26 2 / 3 % =			A
Foreign non-business income tax credit from line 632						
Deduct:						
Foreign investment income (amount L from Part 2 of Schedule 7)	445		x 9 1 / 3 % = (if negative, enter "0")		▶	B
Amount A **minus** amount B (if negative, enter "0")						C
Taxable income from line 360				511,790		
Deduct:						
Amount on line 400, 405, 410, or 425, whichever is the least		124,613				
Foreign non-business income tax credit from line 632		x 25 / 9 =				
Foreign business income tax credit from line 636		x 3 =				
		124,613	▶	124,613		
				387,177		
				x 26 2 / 3 % =	103,247	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780)				101,993		
Deduct: Corporate surtax from line 600				5,732		
Net amount				96,261	▶ 96,261	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least					450	F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the preceding tax year	460	439		
Deduct: Dividend refund for the previous tax year	465			
		439	▶	439 G
Add the total of:				
Refundable portion of Part I tax from line 450 above				
Total Part IV tax payable from line 360 of Schedule 3		123		
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480			
		123	▶	123 H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H	485			562

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3		x 1 / 3		I
Refundable dividend tax on hand at the end of the tax year from line 485 above			562	J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784)				

Part I tax

Base amount of Part I tax – 38.00 % of taxable income (line 360 or amount Z, whichever applies) . . . . . 550 194,480 A

Corporate surtax calculation

Base amount from line A above	194,480	1
Deduct:		
10 % of taxable income (line 360 or amount Z, whichever applies)	51,179	2
Investment corporation deduction from line 620 below		3
Federal logging tax credit from line 640 below		4
Federal qualifying environmental trust tax credit from line 648 below		5
For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:		
28.00 % of taxable income from line 360 a		
28.00 % of taxed capital gains b		6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F) c		
Total of lines 2 to 6	51,179	7
Net amount (line 1 **minus** line 7)	143,301	8

Corporate surtax

line 8 143,301 x 4 % x (Number of days in the tax year before 2008 / Number of days in the tax year) 365 / 365 = 600 5,732 B

Recapture of investment tax credit from line OO in Part 17 of Schedule 31 . . . . . 602 C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income (if it was a CCPC throughout the tax year)

Aggregate investment income from line 440			i
Taxable income from line 360	511,790		
Deduct:			
Amount on line 400, 405, 410, or 425, whichever is the least	124,613		
Net amount	387,177 ▶	387,177	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . 604 D

Subtotal (add lines A, B, C, and D) 200,212 E

Deduct:

Small business deduction from line 430		19,938	9
Federal tax abatement	608	51,179	
Manufacturing and processing profits deduction from amount BB or amount RR of Schedule 27	616		
Investment corporation deduction	620		
(taxed capital gains 624)			
Additional deduction – credit unions from Schedule 17	628		
Federal foreign non-business income tax credit from Schedule 21	632		
Federal foreign business income tax credit from Schedule 21	636		
Accelerated tax reduction from amount N	637		
Resource deduction from line 438			10
General tax reduction for CCPCs from amount K	638	27,102	
General tax reduction from amount S	639		
Federal logging tax credit from Schedule 21	640		
Federal political contribution tax credit	644		
Federal political contributions 646			
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652		
Subtotal		98,219 ▶	98,219 F

Part I tax payable – Line E **minus** line F (enter amount G on line 700) . . . . . 101,993 G

Summary of tax and credits

Federal tax

Part I tax payable	700	101,993
Part I.3 tax payable from Schedule 33, 34, or 35	704	
Part II surtax payable from Schedule 46	708	
Part IV tax payable from Schedule 3	712	123
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		102,116

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 Ontario
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Québec, Ontario, and Alberta)	760	
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765	
Total tax payable	770	102,116 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Allowable refund for non-resident-owned investment corporations from Schedule 26	804	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	B

Refund code 894 Overpayment

Balance (line A **minus** line B) 102,116

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid 102,116

Enclosed payment 898 102,116

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

Certification

I, 950 THIESSEN (Last name) 951 FLORENCE (First name) 954 VICE-PRESIDENT-TREASURER (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2007-05-21 (Date (yyyy/mm/dd)) Signature of the authorized signing officer of the corporation

956 (519) 843-2900 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

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 ☐

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 1

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

Corporation's name	Business Number	Tax year end Year Month Day
CENTRE WELLINGTON HYDRO LTD.	86547 0769 RC0001	2006-12-31

- 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				152,263 A
Add:				
Provision for income taxes – current	101	246,816		
Interest and penalties on taxes	103	69		
Amortization of tangible assets	104	549,664		
Charitable donations from Schedule 2	112	81,225		
Non-deductible meals and entertainment expenses	121	3,430		
Reserves from financial statements – balance at the end of the year	126	239,654		
Subtotal of additions		1,120,858	▶	1,120,858
Other additions:				
Miscellaneous other additions:				
600 Pre-market opening energy variance	290	571,511		
Subtotal of other additions	199	571,511	▶	571,511
Total additions	500	1,692,369	▶	1,692,369
Deduct:				
Capital cost allowance from Schedule 8	403	710,022		
Reserves from financial statements – balance at the beginning of the year	414	541,226		
Subtotal of deductions		1,251,248	▶	1,251,248
Other deductions:				
Miscellaneous other deductions:				
Subtotal of other deductions	499	0	▶	0
Total deductions	510	1,251,248	▶	1,251,248
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				593,384

T2 SCH 1 E (06)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 2

CHARITABLE DONATIONS AND GIFTS

Name of corporation	Business Number	Tax year end Year Month Day
CENTRE WELLINGTON HYDRO LTD.	86547 0769 RC0001	2006-12-31

- 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.
- The donations and gifts are eligible for a five-year carryforward.
- Use this schedule to show a credit transfer following an amalgamation or the windup of a subsidiary as described under subsections 87(1) and 88(1) of the federal *Income Tax Act*.
- For donations and gifts made after March 22, 2004, proposed subsection 110.1(1.2) of the *Income Tax Act* 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 the 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 *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)
Big Brothers Big Sisters	1,000
Community stakeholders Group	4,000
Upper Grand Learning Foundation	200
Food bank	1,000
Groves Memorial Community Hospital Foundation	75,000
Subtotal	81,200
Add: Total donations of less than $100 each	25
Total donations in current taxation year	81,225

		Federal	Quebec	Alberta
Charitable donations at the end of the preceding taxation year				
Deduct: Charitable donations expired after five taxation years	239			
Charitable donations at the beginning of the taxation year	240			
Add:				
Charitable donations transferred on an amalgamation or the windup of a subsidiary	250			
Total current-year charitable donations made (enter this amount on line 112 of Schedule 1) 81,225	210			
Subtotal (line 250 plus line 210) 81,225 ▶		81,225	81,225	81,225
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)	255			
Total charitable donations available		81,225 A	81,225	81,225
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	81,225	81,225	81,225
Charitable donations closing balance	280			

Amounts carried forward – Charitable donations

Year of origin:		Federal	Quebec	Alberta
1st prior year	2005			
2nd prior year	2004			
3rd prior year	2003			
4th prior year	2002			
5th prior year	2001			
6th prior year *	2000			
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 % ..... 445,038 B

Taxable capital gains arising in respect of gifts of capital property
– lines 895 and 896 of Schedule 6, multiplied by the inclusion rate .....
– other .....
Total 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) ..... 445,038 J

Maximum allowable deduction for charitable donations (enter amount A from Part 1, amount J, or net income for tax purposes, whichever is less) ..... 81,225 K

* For credit unions, this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

Part 3 – Gifts to Canada, a province, or a territory

Gifts to Canada, a province, or a territory at the end of the preceding taxation year .....
Deduct: Gifts to Canada, a province, or a territory expired after five taxation years 339 .....
Gifts to Canada, a province, or a territory at the beginning of the taxation 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 the taxation year straddles February 18, 1997, and gifts were made after this date, 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 preceding taxation year				
Deduct: Gifts of certified cultural property expired after five taxation years	439			
Gifts of certified cultural property at the beginning of the taxation year	440			
Add: Gifts of certified cultural property transferred on an amalgamation or the windup of a subsidiary	450			
Total current-year gifts of certified cultural property	410			
Subtotal (line 450 plus line 410)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	455			
Total gifts of certified cultural property available				
Deduct: Amount applied against taxable income (enter this amount on line 313 of the T2 return)	460			
Gifts of certified cultural property closing balance	480			

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Quebec	Alberta
1st prior year	2005			
2nd prior year	2004			
3rd prior year	2003			
4th prior year	2002			
5th prior year	2001			
6th prior year *	2000			
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 preceding taxation year				
Deduct: Gifts of certified ecologically sensitive land expired after five taxation years	539			
Gifts of certified ecologically sensitive land at the beginning of the taxation year	540			
Add: Gifts of certified ecologically sensitive land transferred on an amalgamation or the windup of a subsidiary	550			
Total current-year gifts of certified ecologically sensitive land	510			
Subtotal (line 550 plus line 510)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	555			
Total gifts of certified ecologically sensitive land available				
Deduct: Amount applied against taxable income (enter this amount on line 314 of the T2 return)	560			
Gifts of certified ecologically sensitive land closing balance	580			

Amounts carried forward – Gifts of certified ecologically sensitive land

Year of origin:		Federal	Quebec	Alberta
1st prior year	2005			
2nd prior year	2004			
3rd prior year	2003			
4th prior year	2002			
5th prior year	2001			
6th prior year *	2000			
Total				

* These donations expired in the current year.

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DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year end Year Month Day
CENTRE WELLINGTON HYDRO LTD.	86547 0769 RC0001	2006-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid for purposes of a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act*.
- A recipient corporation is connected with a payer corporation at any time in a taxation year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the sections about Schedule 3 in the *T2 Corporation Income Tax Guide*.
- "X" under column A if dividend received from a foreign source (connected corporation only).
- "X" under column B if the payer corporation is connected.
- "X" under column F1 if the dividends received are eligible to an addition of 45% for the purposes of the dividend tax credit for individuals.
- F2 – Enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received during the taxation year

Do not include dividends received from foreign non-affiliates.

	Name of payer corporation (Use only one line per corporation, abreviating its name if necessary) 200	A	Complete if payer corporation is connected: B 205	C Business Number 210	D Taxation year end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends were paid YYYY/MM/DD 220
1	Sun Life				
2					

Note: If your corporation's taxation year end is different than that of the connected payer corporation, your corporation could have received dividends from more than one taxation year of the payer corporation. If so, use a separate line to provide the information for each taxation year of the payer corporation.

	E Non-taxable dividend under section 83 230	F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d) 240	F1	F2	If payer corporation is not connected, leave these columns blank. G Total taxable dividends paid by connected payer corporation 250	H Dividend refund of the connected payer corporation 260	I Part IV tax before deductions F x 1 / 3 * 270
1		369	X	1			123
2							
Total (enter amount of column F on line 320 of the T2 return)		369					123 J

For dividends received from connected corporations: Part IV tax equals: $\frac{\text{Column F x Column H}}{\text{Column G}}$

* Life insurers are not subject to Part IV tax on subsection 138(6) dividends.
Public corporations (other than subject corporations) do not need to calculate Part IV tax.

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1) 123

Deduct:

Part IV.I tax payable on dividends subject to Part IV tax 320

Subtotal 123

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) 360 123

Part 3 – Taxable dividends paid in the taxation year for purposes of a dividend refund

	A	B	C	D
	Name of connected recipient corporation 400	Business Number 410	Taxation year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD 420	Taxable dividends paid to connected corporations 430
1				

Note

If your corporation's taxation year end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one taxation year of the recipient corporation. If so, use a separate line to provide the information for each taxation year of the recipient corporation.

Total

Total taxable dividends paid in the taxation year to other than connected corporations 450

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (total of column D above plus line 450) 460

Eligible dividends paid that are included in line 460 (memo) (Press F1 for additional information) . . . . .

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

Other dividends paid in the taxation year (total of 510 to 540) . . . . . .

Total dividends paid in the taxation year 500

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 . . . . . .

General Rate Income Pool Workchart (CCPCs)

- Corporations that are Canadian-controlled private corporations (CCPC) or deposit insurance corporations (DIC) within the meaning of the federal *Income Tax Act* (ITA) can use this form to calculate the amount of the general rate income pool and the additions.
- Calculation of the additions to the general rate income pool is made in Part 3. Parts 3B and 3C are treated in a dynamic manner, with the result that this part will only be displayed if either one of the situations listed in Part 1 exists.
- According to the legislative proposals relating to dividend taxation, a CCPC or a DIC can pay an eligible dividend amount, during a taxation year, that is not in excess of its general income rate pool at the end of the year. If it exceeds this amount, it might be liable to pay additional tax on excessive eligible dividend designations as determined under the terms of Part III.1 of the ITA.
- The general rate income pool definition can be found in subsection 89(1) of the ITA.
- For more information, we refer you to the context-sensitive help as well as the *Notice of Ways and Means Motion to Implement Certain Provisions of the Budget Tabled in Parliament on May 2, 2006*, released on October 16, 2006, or any recent version of these provisions.

Part 1 – Eligibility to the various additions

Answer the following questions to determine the corporation's eligibility to the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . [X] Yes [ ] No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? . . . _____
3. If yes, during that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . [X] Yes [ ] No
   If the answer to question 3 is yes, complete Part 3A.

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . [X] Yes [ ] No
5. Corporations that become a CCPC or a DIC . . . . . [ ] Yes [X] No
   If the answer to question 5 is yes, complete Part 3B.

Amalgamation

6. Corporations that were formed as a result of an amalgamation . . . . . [ ] Yes [X] No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . [ ] Yes [ ] No
   If the answer to question 7 is yes, complete Part 3B.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . [ ] Yes [ ] No
   If the answer to question 8 is yes, complete Part 3C.

Winding-up

9. Corporations that wound-up a subsidiary . . . . . [ ] Yes [X] No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 2.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . [ ] Yes [ ] No
    If the answer to question 10 is yes, complete Part 3B.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . [ ] Yes [ ] No
    If the answer to question 11 is yes, complete Part 3C.

Part 2 – Calculation of the general rate income pool (A - B)

A – General rate income pool at the end of the year before adjustment			691,044 A
B – Adjustment of the general rate income pool to take carrybacks into account		–	B
Closing balance of the general rate income pool		=	691,044

Calculation of amount A

The general rate income pool at the end of the year before adjustment is determined based on the following formula:

- **A** = C + 68% (D - E - F) + G + H - I

C – General rate income pool at the end of the preceding taxation year					
2006 addition (calculated in section 3A)			427,395	+	
Subtotal			427,395	=	427,395 C
D – Corporation's taxable income*			511,790		D
E – Small business deduction for the year		19,938			
Conversion factor	x	100 / 16			
Subtotal		= 124,613		–	124,613 E
F – Lesser of total investment's income or taxable income**				–	F
Subtotal (D-E-F)			387,177	=	
Nominal rate			68.00 %	x	
Subtotal			263,280	+	263,280
G – Amounts received from other corporations					
i) Eligible dividends received by the corporation during the year					
Included in Schedule 3			369		
Not included in Schedule 3				+	
Subtotal			369	=	
ii) Deductible amounts under section 113 for the particular taxation year				+	
Subtotal (i)+ii))			369	=	369 G
H – Additions for corporations that become a CCPC's, that were formed as a result of an amalgamation or that wound-up a subsidiary.				+	H
I – Eligible dividends paid in the preceding year***					
i) Eligible dividends paid in its preceding taxation year					
ii) Excessive eligible dividends designations in its preceding taxation year				–	
Subtotal (i)-ii))				=	I
General rate income pool at the end of the year before adjustment				=	691,044 A

* If the corporation is a deposit insurance corporation, enter zero.
** If the corporation is not a CCPC, enter zero.
*** If the corporation has not changed status to become a CCPC.

Calculation of amount B

The general rate income pool to take carrybacks into account is determined based on the following formula:

- **B** = 68% (a - b)

a) Total of the corporation's full rate taxable incomes for the preceding three taxation years determined without reference to any specified future tax consequences, for those preceding taxation years that arise in respect of the particular taxation year			a
b) Total of adjusted corporation's full taxable incomes for those preceding years		–	b
Subtotal		=	
Nominal rate		x	68.00 %
Adjustment of the general rate income pool to take carrybacks into account		=	B

Part 3A – Calculation of the addition for the CCPCs in 2006 (A - B)

The addition to the general rate income pool applies to a corporation that was, or that would have been but for an election under subsection 89(11) (election not to be a CCPC), throughout its first taxation year that includes any part of January 1, 2006, a Canadian-controlled private corporation.

The term "full rate taxable income" is defined in subsection 123.4(1). In broad terms, the full rate taxable income correspond to the portion of the taxable income for the year that is not exempt from tax and that did not benefit from the various special effective rates.

The 2006 addition is determined based on the following calculation: 63% multiplied by the full rate taxable income for its taxation years that ended after 2000 and before 2006.

A – Taxable income and dividends received after 2000 and before 2006

Full rate taxable income		678,405		
Nominal rate	x	63.00 %		
Subtotal	=	427,395		
Total taxable dividends received from a connected payer corporation	+			
Subtotal	=	427,395 ▶	427,395	A

B – Taxable dividends paid after 2000 and before 2006

Total of the taxable dividends paid	–		B
Addition for the CCPCs in 2006 (Carry this amount to line C of part 2 of the corporation's general rate income pool)	=	427,395	

Workchart for the 2006 addition (CCPCs)

Addition to the general rate income pool is determined under subsection 89(7) ITA. It applies to a corporation that was, or that would have been but for an election under subsection 89(11) (election not to be a CCPC), throughout its first taxation year that includes any part of January 1, 2006, a CCPC.

In order for the addition to be calculated properly in the general rate income pool, enter the required amounts, according to the type of corporation, for each of the corporation's taxation year that ended after 2000 and before 2006. If the corporation has more than one taxation year ending within the same calendar year, add the required amounts and carry the total over to the column corresponding to that year.

Section 1 corresponds to the full rate taxable income for corporations that are CCPCs. Section 2 corresponds to the full rate taxable income for corporations that are neither CCPCs nor investment corporations.

If, for a taxation year, the corporation is an investment corporation, a mortgage investment corporation (MIC) or a mutual funds corporation, do not enter anything in sections 1 and 2 in the columns corresponding to that year. Investment corporations have a full rate taxable income of zero.

Select this check box if you want to import amounts from the *Five Year Comparative Summary* into this workchart. ☐

Note: Any amounts imported from the *Five Year Comparative Summary* should be reviewed to ensure that they reflect any reassessments received or other adjustments made subsequent to the filing of the original returns.

Taxation year(s) ending on	2001	2002	2003	2004	2005	Total
Part 1 – Corporations that are CCPCs (123.4(1)b) ITA)						
Taxable income for the year (subtract line 370 from line 360 of Schedule 200)					828,245	
Minus amount giving entitlement to the deduction on manufacturing and processing profits (lesser of amounts V and Y from Part 9 of Schedule 27)						
Minus amount giving entitlement to the deduction for electrical energy and steam (amount QQ from Part 13 of Schedule 27)						
Minus taxable income from resources for the year (line 435 of Schedule 200)						
Minus amount giving entitlement to the credit union deduction (amount E from Part 3 of Schedule 17)						
Minus amount giving entitlement to small business deduction (lesser of amounts A, B, C or F of the "Small business deduction" section of Schedule 200)					149,840	
Minus total investment income (line 440 of Schedule 200)						
Minus amount giving entitlement to CCPC deduction under subsection 123.4(3) (accelerated tax reduction) (amount M of the "Accelerated tax reduction" section of Schedule 200).						
Total of the full rate taxable income for CCPCs					678,405	678,405

Part 2 – Corporations that are neither CCPCs nor investment coporations (123.4(1)a) ITA)						
Taxable income for the year (subtract line 370 from line 360 of Schedule 200)						
Minus amount giving entitlement to the deduction on manufacturing and processing profits (lesser of amounts V and Y from Part 9 of Schedule 27)						
Minus amount giving entitlement to the deduction for electrical energy and steam (amount QQ from Part 13 of Schedule 27)						
Minus taxable income from resources for the year (line 435 of Schedule 200)						
Minus amount giving entitlement to the credit union deduction (amount E from Part 3 of Schedule 17)						
Total of the full rate taxable income for corporations that are neither CCPCs nor investment corporations						

Taxation year(s) ending on	2001	2002	2003	2004	2005	Total
Part 3 – Total deductible dividends under subsection 112 (1) received from a connected corporation						
Total taxable dividends received from a connected payer corporation						

Part 4 – Taxable dividends paid						
Taxable dividends paid included on line 460 of Schedule 3						
Other taxable dividends paid not included in Schedule 3						
Total taxable dividends paid						

Addition for CCPCs in 2006 (63% (Total of Part 1 + Total of Part 2) + Total of Part 3 - Total of Part 4) (if negative, enter "0")	427,395

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SCHEDULE 7

CALCULATION OF AGGREGATE INVESTMENT INCOME AND ACTIVE BUSINESS INCOME

Name of corporation	Business Number	Tax year end Year Month Day
CENTRE WELLINGTON HYDRO LTD.	86547 0769 RC0001	2006-12-31

- 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	
The eligible portion of taxable capital gains included in income for the year		001	002	A
Eligible portion of allowable capital losses for the year (including allowable business investment losses)		009	012	B
Net capital losses of other years claimed on line 332 on the T2 return			022	C
Total of amounts B and C				D
Amount A **minus** amount D (if negative, enter "0")				E
Total income from property (in box 32 include income from a specified investment business carried on in Canada other than income from a source outside Canada)				
Taxable dividends	369		369	
Other property income				
Total income from property	369	019	032 369	F
Exempt income		029	042	G
Amounts received from NISA Fund No. 2 (CAIS) that were included in computing the corporation's income for the year			052	H
Taxable dividends deductible (total of Column F on Schedule 3)	369	049	062 369	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	369		369	K
Amount F **minus** amount K				L
Total of amount E **plus** amount L				M
Total losses from property (in box 82 include losses from a specified investment business carried on in Canada other than a loss from a source outside Canada)		069	082	N
Amount M **minus** amount N (if negative, enter "0")		079 L	092 O	

Note: The aggregate investment income is the aggregate world source income.

Enter amount L, foreign investment income, on line 445 of the T2 return.
Enter amount O, aggregate investment income, on line 440 of the T2 return.

T2 SCH 7 E (06)

Canada

Net taxable dividends	Canadian	Foreign	Total
Taxable dividends deducted per schedule 3	369		369
Less: Expenses related to such dividends			
Total expenses			
Net taxable dividends	369		369

Part 3 – Specified partnership income

A	B	C
Partnership name 200	Total income (loss) of partnership from an active business 300	Corporation's share of amount in column B 310

D	E	F	G	H	I
Adjustments [add prior-year reserves under subsection 34.2(5), and deduct expenses incurred to earn partnership income, including any reserve under subsection 34.2(4)] 315	Corporation's income (loss) of the partnership (column C **plus** column D) 320	Number of days in the partnership's fiscal period 325	Prorated business limit (column C ÷ column B) × [business limit* × (column F ÷ 365)] (if column C is negative, enter "0")** 330	Column E **minus** column G (if negative, enter "0")	Lesser of columns E and G (if column E is negative, enter "0") 340
Total 350				Total 385	360

Corporation's losses for the year from an active business carried on in Canada (other than as a member of a partnership) – enter as a positive amount 370

Specified partnership loss of the corporation for the year – enter as a positive amount (total of all negative amounts in column E) 380

Total of lines 370 and 380 . . . . . ▶ J

Amount at line 385 or line J, whichever is less 390

Specified partnership income (line 360 **plus** line 390) 400

* Use one of the following business limits to calculate column G, whichever applies:

- $250,000 if the corporation's tax year ends in 2004;
- $300,000 if the corporation's tax year ends in 2005 or 2006; or
- $400,000 if the corporation's tax year ends after 2006.

** When a partnership carries on more than one business, one of which generates income and another of which realizes a loss, the loss is not netted against the partnership's income.

Part 4 – Determination of partnership income

Corporation's share of partnership income from active businesses carried on in Canada after deducting related expenses – from line 350 above (if the net amount is negative, enter "0" on line O) . . . . . K

Add: Specified partnership loss (from line 380 above) L

Subtotal M

Deduct: Specified partnership income (from line 400 above) . . . . . N

Partnership income (enter on line S below) . . . . . 450 O

Part 5 – Income from active business carried on in Canada

Net income for income tax purposes from line 300 of the T2 return			593,384	P
Deduct: Foreign business income after deducting related expenses*	500			
Taxable capital gains **minus** allowable capital loss – amount A **minus** amount B* (page 1)**				
Net property income = amount F **minus** amount G, H, and N* (page 1)		369 Q		
Personal services business income after deducting related expenses*	520			
		369 ▶	369	
		Net amount	593,015	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")			593,015	T

* If negative, **add** instead of **subtracting**.
**This amount may only be negative to the extent of any allowable business investment losses.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
CENTRE WELLINGTON HYDRO LTD.	86547 0769 RC0001	2006-12-31

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 [X]

	1 Class number **200**	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) **201**	3 Cost of acquisitions during the year (new property must be available for use)* **203**	4 Net adjustments** **205**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) **207**	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** **211**	7 Reduced undepreciated capital cost	8 CCA rate % **212**	9 Recapture of capital cost allowance (line 107 of Schedule 1) **213**	10 Terminal loss (line 404 of Schedule 1) **215**	11 Capital cost allowance (column 7 **multiplied** by column 8; or a lower amount) (line 403 of Schedule 1)**** **217**	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) **220**
1	1		10,170,846	1,500		0	750	10,171,596	4	0	0	406,864	9,765,482
2	8		787,467	326,527		0	163,264	950,730	20	0	0	190,146	923,848
3	10		161,020	291,460		0	145,730	306,750	30	0	0	92,025	360,455
4	10		35,011			0		35,011	30	0	0	10,503	24,508
5	17		13,016			0		13,016	8	0	0	1,041	11,975
6	45		3,865	20,459		0	10,230	14,094	45	0	0	6,342	17,982
7	12			6,202		0	3,101	3,101	100	0	0	3,101	3,101
		Total	11,171,225	646,148			323,075	11,494,298				710,022	11,107,351

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) plus or minus certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (06)

Canada

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return

Tax return

Additions for tax purposes – Schedule 8 regular classes		646,148		
Additions for tax purposes – Schedule 8 leasehold improvements	+			
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+			
	+			
Total additions per books	=	646,148		646,148
Proceeds up to original cost – Schedule 8 regular classes				
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
	+			
Total proceeds per books	=		–	
Depreciation and amortization per accounts – Schedule 1			–	549,664
Loss on disposal of fixed assets per accounts			–	
Gain on disposal of fixed assets per accounts			+	
Net change per tax return			=	96,484

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		7,086,954
Opening net book value	–	6,990,470
Net change per financial statements	=	96,484

If the amounts from the tax return and the financial statements differ, explain why below

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on amalgamation or wind-up of subsidiary	Add	Deduct	Balance at the end of the year
1	Recoveries of regulatory assets	286,757			546,755	-259,998
2	Settlement variance	169,696		244,968		414,664
3	Post-employment benefits	84,773		215		84,988
4						
	Reserves from Part 2 of Schedule 13					
	Totals	541,226		245,183	546,755	239,654

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
CENTRE WELLINGTON HYDRO LTD.	86547 0769 RC0001	2006-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	CORPORATION OF THE TOWNSHIP OF CENTRE WELLI	87256 7136 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

CLIENT'S COPY

Attachment to CT23 Corporations Tax and Annual Return

Centre Wellington Hydro Ltd.
Ontario Corporation Tax Account # 1800241

Taxes payable for the year ended December 31, 2007 are comprised of:

Federal Large Corporations Tax	-
Federal Income Tax	288,636
Federal Part IV Tax	141
Provincial Corporations Tax	169,552
Provincial Corporate Minimum Tax	
Provincial Capital Tax	14,991
Total Provincial Payment in Lieu of Taxes	$ 473,320
Less: Provincial instalments paid	(166,080)
Balance owing	$ 307,240

Ontario

Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

2007 CT23 Corporations Tax and Annual Return

For taxation years commencing after December 31, 2004

Corporations Tax Act – Ministry of Finance (MOF)
Corporations Information Act – Ministry of Government Services (MGS)

This form is a combination of the Ministry of Finance (MOF) **CT23 Corporations Tax Return** and the Ministry of Government Services (MGS) **Annual Return**. Page 1 is a common page required for both Returns. For tax purposes, depending on which criteria the corporation satisfies, it must complete either the **Exempt from Filing (EFF)** declaration on page 2 or file the **CT23 Return** on pages 3-17. Corporations that **do not** meet the EFF criteria but **do** meet the Short-Form criteria, may request and file the **CT23 Short-Form Return** (see page 2).

The **Annual Return** (common page 1 and MGS Schedule A on pages 18 and 19, and Schedule K on page 20) contains non-tax information collected under the authority of the *Corporations Information Act* for the purpose of maintaining a public database of corporate information. This return must be completed by Ontario share-capital corporations or Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

Ministry Use

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* [X] Yes [ ] No **Page 1 of 20**

Corporation's Legal Name *(including punctuation)*

CENTRE WELLINGTON HYDRO LTD.

Ontario Corporations Tax Account No. (MOF)

1800241

Mailing Address

730 GARTSHORE STREET
PO BOX 217
FERGUS
ON CA N1M 2W8

This Return covers the Taxation Year

Start: year month day 2007-01-01

End: 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: year month day 2000-08-22

Registered/Head Office Address

730 GARTSHORE STREET
PO BOX 217
FERGUS
ON CA N1M 2W8

Ontario Corporation No. (MGS): 1435240

Location of Books and Records

730 GARTSHORE STREET
PO BOX 217
FERGUS
ON CA N1M 2W8

Canada Revenue Agency Business No.
If applicable, enter: 86547 0769 RC0001

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
FLORENCE THIESSEN	(519) 843-2900	

Jurisdiction Incorporated: Ontario

Address of Principal Office in Ontario *(Extra-Provincial Corporations only)* (MGS)

Ontario Canada

If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased:

Commenced: year month day

Ceased: year month day

[X] *Not Applicable*

Former Corporation Name *(Extra-Provincial Corporations only)* [X] *Not Applicable* (MGS)

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). ▶

No. of Schedule(s)

If there is **no change** to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check (X) this box. Schedule(s) A and K are not required (MGS). ▶ [X] No Change

Preferred Language / *Langue de préférence*

[X] English *anglais* [ ] French *français*

Ministry Use

Certification (MGS)

I certify that all information set out in the **Annual Return** is true, correct and complete.

Name of Authorized Person *(Print clearly or type in full)*

FLORENCE THIESSEN

Title D [ ] Director O [X] Officer P [ ] Other individuals having knowledge of the Corporation's business activities

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

Please check applicable (X) box(es) and complete required information.

Type of corporation

1

1 [X] Canadian-controlled Private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))

2 [ ] Other Private

3 [ ] Public

4 [ ] Non-share Capital

5 [ ] Other *(specify)* ▼

Share Capital with full voting rights owned by Canadian Residents (nearest percent) 100 %

2

1 [ ] Family Farm corporation s.1(2)

2 [ ] Family Fishing corporation s.1(2)

3 [ ] Mortgage Investment corporation s.47

4 [ ] Credit Union s.51

5 [ ] Bank Mortgage subsidiary s.61(4)

6 [ ] Bank s.1(2)

7 [ ] Loan and Trust corporation s.61(4)

8 [ ] Non-resident corporation s.2(2)(a) or (b)

9 [ ] Non-resident corporation s.2(2)(c)

10 [ ] Mutual Fund corporation s.48

11 [ ] Non-resident owned Investment corporation s.49

12 [ ] Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)

14 [ ] Bare Trustee corporation

15 [ ] Branch of Non-resident s.63(1)

16 [ ] Financial institution prescribed by Regulation only

17 [ ] Investment Dealer

18 [ ] Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale

19 [X] Hydro successor, municipal electrical utility or subsidiary of either

20 [ ] Producer and seller of steam for uses other than for the generation of electricity

21 [ ] Insurance Exchange s.74.4

22 [ ] Farm Feeder Finance Co-operative corporation

23 [ ] Professional corporation (incorporated professionals only)

[ ] This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)

[ ] Amended Return

[ ] Taxation year end change – Canada Revenue Agency approval required

[ ] Final taxation year up to dissolution *(Note: for discontinued businesses, see guide.)*

[ ] Final taxation year before amalgamation

[ ] The corporation has a floating fiscal year end

[ ] There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario

[ ] There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year

If checked, date control was acquired year month day

[ ] The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)

[ ] First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)

[ ] Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes	No	
[ ]	[X]	Was the corporation inactive throughout the taxation year?
[X]	[ ]	Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?

Are you requesting a refund due to:

[ ]	[X]	the Carry-back of a Loss?
[ ]	[X]	an Overpayment?
[ ]	[X]	a Specified Refundable Tax Credit?
[ ]	[X]	Are you a member of a Partnership or Joint Venture?

Complete if applicable

Ontario Retail Sales Tax Vendor Permit no. (Use head office no.)

Ontario Employer Health Tax Account no. (Use head office no.)

Specify major business activity

Allocation – If you carry on a business through a permanent establishment in a jurisdiction outside Ontario, you may allocate that portion of taxable income deemed earned in that jurisdiction to that jurisdiction (s.39) (Int.B. 3008).

DOLLARS ONLY

Net Income (loss) for Ontario purposes (per reconciliation schedule, page 15)	±	From 690	1,216,728 .
Subtract: Charitable donations	–	1	5,220 .
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	424 .
Subtract: Ontario political contributions *(Attach Schedule 2A)* (Int.B. 3002R)	–	4	.
Subtract: Federal Part VI.1 tax . x 3	–	5	.
Subtract: Prior years' losses applied – Non-capital losses From 715	–	From 704	.
Net capital losses (page 16) . x inclusion rate 50.000000 % =	–	714	.
Farm losses	–	From 724	.
Restricted farm losses	–	From 734	.
Limited partnership losses	–	From 754	.
Taxable Income (Non-capital loss)	=	10	1,211,084 .
Addition to taxable income for unused foreign tax deduction for federal purposes	+	11	.
Adjusted Taxable Income 10 + 11 (if 10 is negative, enter 11)	=	20	1,211,084 .

Taxable Income

Number of Days in Taxation Year

From 10 (or 20 if applicable)	1,211,084 .	x	30	100.0000 % Ontario Allocation	x	12.5 %	x	Days after Dec. 31, 2002 and before Jan. 1, 2004: 33 ___ ÷ 73 Total Days 365	= +	29	.
From 10 (or 20 if applicable)	1,211,084 .	x	30	100.0000 % Ontario Allocation	x	14 %	x	Days after Dec. 31, 2003: 34 365 ÷ 73 Total Days 365	= +	32	169,552 .
Income Tax Payable (before deduction of tax credits) 29 + 32									=	40	169,552 .

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

If this section is not completed, the IDSBC will be denied.

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? (X) [X] Yes [ ] No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))		50	958,496 .
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	+ 51	1,211,084 .	
Add: Losses of other years deducted for federal purposes (fed.s.111)	+ 52	.	
Subtract: Losses of other years deducted for Ontario purposes (s.34)	– 53	.	
	=	1,211,084 .	54 1,211,084 .
Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1)		55	400,000 .

Ontario Business Limit Calculation

320,000 x	Days after Dec. 31, 2002 and before Jan. 1, 2004: 31 ___ ÷ ** 365	= +	46	.			
400,000 x	Days after Dec. 31, 2003: 34 365 ÷ ** 365	= +	47	400,000 .			
Business Limit for Ontario purposes 46 + 47		=	44	400,000 .	x	Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated. 48 100.0000 %	= 45 400,000 .

Income eligible for the IDSBC From 30 100.0000 % ***Ontario Allocation x 56 400,000 . = 60 400,000 .
Least of 50 , 54 or 45

* ***Note:*** *Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)*

** ***Note:*** *Adjust accordingly for a floating taxation year and use 366 for a leap year.*

*** ***Note:*** *Ontario Allocation for IDSBC purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).*

continued on Page 5

Income Tax *continued from Page 4*

Calculation of IDSBC Rate 7 % x (Number of Days in Taxation Year: Days after Dec. 31, 2002 and before Jan. 1, 2004 [31] ÷ Total Days [73] 365) = + [89]

8.5 % x (Days after Dec. 31, 2003 [34] 365 ÷ Total Days [73] 365) = + [90] 8.5000

IDSBC Rate for Taxation Year [89] + [90] = [78] 8.5000

Claim From [60] 400,000 . x From [78] 8.5000 % = [70] 34,000 .

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount 400,000 in [114] below.

Surtax on Canadian-controlled Private Corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

Associated Corporation - The Taxable Income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

***Taxable Income of the corporation** From [10] (or [20] if applicable) + [80] 1,211,084 .

If you are a member of an associated group (X) [81] (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	* Taxable Income (if loss, enter nil)
			+ [82]
			+ [83]
			+ [84]

Aggregate Taxable Income [80] + [82] + [83] + [84], etc. = [85] 1,211,084 .

320,000 x (Number of Days in Taxation Year: Days after Dec. 31, 2002 and before Jan. 1, 2004 [31] ÷ Total Days [73] 365) = + [115]

400,000 x (Days after Dec. 31, 2003 [34] 365 ÷ Total Days [73] 365) = + [116] 400,000 .

[115] + [116] = 400,000 . ▶ – [114] 400,000 .

(If negative, enter nil) = [86] 811,084 .

Calculation of Specified Rate for Surtax 4.6670 % x (Number of Days in Taxation Year: Days after Dec. 31, 2002 [38] 365 ÷ Total Days [73] 365) = + [97] 4.6670

From [86] 811,084 . x From [97] 4.6670 % = [87] 37,853 .

From [87] 37,853 . x From [60] 400,000 . ÷ From [114] 400,000 . = [88] 37,853 .

Surtax Lesser of [70] or [88] = [100] 34,000

* ***Note: Short Taxation Years*** – Special rules apply where the taxation year is less than 51 weeks for the corporation and/or any corporation associated with it.

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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

From 100 34,000 ÷ From 30 100.0000 % ÷ From 78 8.5000 % = 121 400,000

*Ontario Allocation

Lesser of 56 or 121 - + 122 400,000

120 – 56 + 122 - = 130

Taxable Income - + From 10 1,211,084

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 1,211,084 X Allocation % to jurisdictions outside Canada - - - - - - - - - 140

Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses - - - - - - - - - 141 257,808

10 – 56 + 122 – 140 – 141 - = 142 953,276

Claim

143 Lesser of 130 or 142		X	From 30 100.0000 % Ontario Allocation	X	1.5 %	X	Number of Days in Taxation Year: Days after Dec. 31, 2002 and before Jan. 1, 2004 33 ÷ Total Days 73 365	= +	154	
143 Lesser of 130 or 142		X	From 30 100.0000 % Ontario Allocation	X	2 %	X	Days after Dec. 31, 2003 34 365 ÷ Total Days 73 365	= +	156	

M&P claim for taxation year 154 + 156 - = 160

** **Note:** Ontario Allocation for M&P Credit purposes may differ from 30 if Taxable Income is allocated to foreign jurisdictions. See special rules (s.43(1))*

Manufacturing and Processing Profits Credit for Electrical Generating Corporations = 161

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity - - - - - - - - - - = 162

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). *(Attach schedule)* - 170

Credit for Investment in Small Business Development Corporations (SBDC)

Applies if you have an unapplied, previously approved credit from prior years' investments in new issues of equity shares in Small Business Development Corporations. Any unused portion may be carried forward indefinitely and applied to reduce subsequent years' income taxes. (Refer to the former *Small Business Development Corporations Act*)

Eligible Credit 175 Credit Claimed 180

Subtotal of Income Tax 40 – 70 + 100 – 110 – 160 – 161 – 162 – 170 – 180 - - - - = 190 169,552

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Income Tax *continued from Page 6*

Specified Tax Credits *(Refer to Guide)*

Ontario Innovation Tax Credit (OITC) (s.43.3) ***Applies*** to scientific research and experimental development in Ontario.
Eligible Credit From 5620 OITC Claim Form *(Attach original Claim Form)* + 191

Co-operative Education Tax Credit (CETC) (s.43.4) ***Applies*** to employment of eligible students.
Eligible Credit From 5798 CT23 Schedule 113 *(Attach Schedule 113)* + 192

Ontario Film & Television Tax Credit (OFTTC) (s.43.5)
Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. Name of Production 204
Eligible Credit From 5850 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 193

Graduate Transitions Tax Credit (GTTC) (s.43.6) No. of Graduates From 6596
Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005. 194
Eligible Credit From 6598 CT23 Schedule 115 *(Attach Schedule 115)* + 195

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)
Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.
Eligible Credit From 6900 OBPTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + 196

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)
Applies to labour relating to computer animation and special effects on an eligible production.
Eligible Credit From 6700 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 197

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)
Applies to qualifying R&D expenditures under an eligible research institute contract.
Eligible Credit From 7100 OBRITC Claim Form *(Attach original Claim Form)* + 198

Ontario Production Services Tax Credit (OPSTC) (s.43.10)
Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.
Eligible Credit From 7300 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 199

Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)
Applies to qualifying labour expenditures of eligible products for the taxation year.
Eligible Credit From 7400 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 200

Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)
Applies to qualifying expenditures in respect of eligible Canadian sound recordings.
Eligible Credit From 7500 OSRTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + 201

Apprenticeship Training Tax Credit (ATTC) (s.43.13) No. of Apprentices From 5896
Applies to employment of eligible apprentices. 202
Eligible Credit From 5898 CT23 Schedule 114 *(Attach Schedule 114)* + 203

Other (specify) _____ + 203.1

Total Specified Tax Credits 191 + 192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 + 203 + 203.1 = 220

Specified Tax Credits *Applied to reduce Income Tax* = 225

Income Tax 190 – 225 **OR Enter NIL if reporting Non-Capital Loss** *(amount cannot be negative)* = 230 169,552

To determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see **Determination of Applicability** section for the CMT on **Page 8.** If CMT is not applicable, transfer amount in 230 to Income Tax in **Summary** section on **Page 17.**

OR

If CMT is not applicable for the current taxation year but your corporation has CMT Credit Carryovers that you want to apply to reduce income tax otherwise payable, then proceed to and complete the **Application of CMT Credit Carryovers** section part B, on **Page 8.**

Corporate Minimum Tax (CMT)

DOLLARS ONLY

Total Assets of the corporation + 240 16,861,130 .

Total Revenue of the corporation + 241 13,239,297 .

The above amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

If you are a member of an associated group (X) 242 ☐ (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Total Assets	Total Revenue
			+ 243 .	+ 244 .
			+ 245 .	+ 246 .
			+ 247 .	+ 248 .
Aggregate Total Assets 240 + 243 + 245 + 247 , etc.			= 249 16,861,130 .	
Aggregate Total Revenue 241 + 244 + 246 + 248 , etc.				= 250 13,239,297 .

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 512,293 . (If negative, enter zero) × From 30 100.0000 % (Ontario Allocation) X 4 % = 276 20,492 .

Subtract: Foreign Tax Credit for CMT purposes *(Attach Schedule)* – 277 .

Subtract: Income Tax – From 190 169,552 .

Net CMT Payable (If negative, enter Nil on Page 17.) = 280 -149,060 .

If 280 is less than zero and you do not have a CMT credit carryover, transfer 230 from **Page 7** to **Income Tax Summary, on Page 17.**

If 280 is less than zero and you have a CMT credit carryover, complete A & B below.

If 280 is greater than or equal to zero, transfer 230 to **Page 17** and transfer 280 to **Page 17, and** to **Part 4 of Schedule 101: Continuity of CMT Credit Carryovers.**

CMT Credit Carryover available From Schedule 101 — From 2333 .

Application of CMT Credit Carryovers

A. Income Tax (before deduction of specified credits) + From 190 169,552 .

Gross CMT Payable + From 276 20,492 .

Subtract: Foreign Tax Credit for CMT purposes – From 277 .

If 276 – 277 is negative, enter NIL in 290 = 20,492 . – 290 20,492 .

Income Tax eligible for CMT Credit = 300 149,060 .

B. Income Tax (after deduction of specified credits) + From 230 169,552 .

Subtract: CMT credit used to reduce income taxes – 310 .

Income Tax = 320 169,552 .

Transfer to page 17

If A & B apply, 310 *cannot exceed the lesser of* 230 , 300 *and your CMT credit carryover available* 2333 .

If only B applies, 310 *cannot exceed the lesser of* 230 *and your CMT credit carryover available* 2333 .

Capital Tax *(Refer to Guide and Int.B. 3011R)*

If your corporation is a Financial Institution (s.58(2)), complete lines 480 *and* 430 *on page 10 then proceed to page 13.*

If your corporation is not a member of an associated group and/or partnership and the Gross Revenue and Total Assets as calculated on page 10 in 480 *and* 430 *are both $3,000,000 or less, your corporation is exempt from Capital Tax for the taxation year, except for a branch of a non-resident corporation. A corporation that meets these criteria should disregard all other Capital Tax items (including the calculation of Taxable Capital). Enter NIL in* 550 *on page 12 and complete the return from that point. All other corporations must compute their Taxable Capital in order to determine their Capital Tax payable.*

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

Any Assets and liabilities of a corporation that are being utilized in a joint venture must be included along with the corporation's other Assets and liabilities when calculating its Taxable Paid-up Capital.

Special rules and rates apply to Non-Resident corporations (s.63, s.64 and s.69(3)).

Paid-up Capital of Non-resident: Paid-up capital employed in Canada of a non-resident subject to tax by virtue of s.2(2)(a) or 2(2)(b), and whose **business is not carried on solely in Canada** is deemed to be the **greater** of (1) taxable Income in Canada divided by 8 percent or (2) total assets in Canada minus certain indebtedness in accordance with the provisions of s.63(1)(a) (Int.B. 3010).

Paid-up Capital

Paid-up capital stock (Int.B. 3012R and 3015R)	+	350	5,035,066
Retained earnings (if deficit, deduct) (Int.B. 3012R)	±	351	2,554,297
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	+	352	
Loans and advances *(Attach schedule)* (Int.B. 3013R)	+	353	5,262,042
Bank loans (Int.B. 3013R)	+	354	
Bankers acceptances (Int.B. 3013R)	+	355	
Bonds and debentures payable (Int.B. 3013R)	+	356	
Mortgages payable (Int.B. 3013R)	+	357	
Lien notes payable (Int.B. 3013R)	+	358	
Deferred credits (including income tax reserves, and deferred revenue where it would also be included in paid-up capital for the purposes of the large corporations tax) (Int.B. 3013R)	+	359	
Contingent, investment, inventory and similar reserves (Int.B. 3012R)	+	360	
Other reserves not allowed as deductions for income tax purposes *(Attach schedule)* (Int.B. 3012R)	+	361	4,955,166
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	+	362	
Subtotal	=	370	17,806,571
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012R)	–	371	
Deductible R & D expenditures and ONTTI costs deferred for income tax if not already deducted for book purposes (Int.B. 3015R)	–	372	
Total Paid-up Capital	=	380	17,806,571
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	17,806,571

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	37,268
Loans and advances to unrelated corporations	+	405	19,655
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	56,923

continued on Page 10

Total Assets (Int.B. 3015R) *DOLLARS ONLY*

Total Assets per balance sheet	+	420	16,861,130 .
Mortgages or other liabilities deducted from assets	+	421	.
Share of partnership(s)/joint venture(s) total assets *(Attach schedule)*	+	422	.
Subtract: Investment in partnership(s)/joint venture(s)	–	423	.
Total Assets as adjusted	=	430	16,861,130 .
Amounts in 360 and 361 (if deducted from assets)	+	440	4,952,167 .
Subtract: Amounts in 371, 372 and 381	–	441	.
Subtract: Appraisal surplus if booked	–	442	.
Add or Subtract: Other adjustments (specify on an attached schedule)	±	443	.
Total Assets	=	450	21,813,297 .

Investment Allowance (410 ÷ 450) x 390 Not to exceed 410 = 460 46,467 .

Taxable Capital 390 – 460 = 470 17,760,104 .

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue) 480 13,239,297 .

Total Assets (as adjusted) From 430 16,861,130 .

Calculation of Capital Tax for all Corporations except Financial Institutions

Note: *This version (2007) of the CT23 may only be used for a taxation year that commenced after December 31, 2004.*

Financial Institutions use calculations on page 13.

Important: If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only Section A below.

OR If the corporation is **not** a member of an associated group and/or partnership, complete Section B below, then review only the Capital Tax calculations in Section C on page 11, selecting and completing the one specific subsection (e.g. C3) that applies to the corporation.

OR If the corporation **is** a member of an associated group and/or partnership, complete Section B below and Section D on page 11, and if applicable, complete Section E or Section F on page 12. Note: if the corporation is a member of a connected partnership, please refer to the CT23 Guide for additional instructions before completing the Capital Tax section.

SECTION A

This section applies only if the corporation is a family farm corporation, a family fishing corporation or a credit union that is not a Financial Institution (Int.B. 3018).

Enter NIL in 550 on page 12 and complete the return from that point.

SECTION B

B1. Calculation of Taxable Capital Deduction (TCD)

		Number of Days in Taxation Year					
		Days after Dec. 31, 2004 and before Jan. 1, 2006	Total Days				
7,500,000	x	36	÷ 73 365	= +	501		.
		Days after Dec. 31, 2005 and before Jan. 1, 2007	Total Days				
10,000,000	x	37	÷ 73 365	= +	502		.
		Days after Dec. 31, 2006 and before Jan. 1, 2008	Total Days				
12,500,000	x	38 365	÷ 73 365	= +	504	12,500,000	.
		Days after Dec. 31, 2007	Total Days				
15,000,000	x	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 %	x	556	÷ 73 365	= +	511		%
		Days after Dec. 31, 2006 and before Jan. 1, 2009	Total Days				
0.285 %	x	557 365	÷ 73 365	= +	512	0.2850	%
Capital Tax Rate		511 + 512		=	516	0.2850	%

continued on Page 11

Capital Tax Calculation *continued from Page 10*

SECTION C

This section applies if the corporation is **not** a member of an associated group and/or partnership.

C1. If 430 and 480 on page 10 are both $3,000,000 or less, enter NIL in 550 on page 12 and complete the return from that point.

C2. If Taxable Capital in 470 is **equal to or less than the TCD** in 503, enter NIL in 550 on page 12 and complete the return from that point.

C3. If Taxable Capital in 470 **exceeds the TCD** in 503, complete the following calculation and transfer the amount from 523 to 543 on page 12, and complete the return from that point.

+	From 470	17,760,104 •											
−	From 503	12,500,000 •											
=	471	5,260,104 •	x	From 30	100.0000 %	x	From 516	0.2850 %	x	555 365 / 365 (366 if leap year)	=	+ 523	14,991 •
					Ontario Allocation			Capital Tax Rate		Days in taxation year. *If floating taxation year, refer to Guide.*			*Transfer to 543 on page 12 and complete the return from that point*

SECTION D

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either 509 or 524 and complete this section before you can calculate your Capital Tax Calculation under either Section E or Section F.

D1. ☐ 509 (X if applicable)

All corporations that you are associated with do **not** have a permanent establishment in Canada.

If Taxable Capital 470 on page 10 is equal to or less than the TCD 503 on page 10, enter NIL in 550 on page 12 and complete the return from that point.

If Taxable Capital 470 on page 10 exceeds the TCD 503 on page 10, proceed to **Section E**, enter the TCD amount in 542 in Section E, and complete Section E and the return from that point.

D2. ☐ 524 (X if applicable)

One or more of the corporations that you are associated with **maintains** a permanent establishment in Canada.

You and your associated group may continue to allocate the TCD by completing the Calculation below. Or, the associated group **may file an election** under subsection 69(2.1) of the *Corporations Tax Act*, whereby total assets are used to allocate the TCD among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as **Net Deduction**) of the capital tax effect relating to the TCD to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group.

The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year.

In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

D2. Calculation is on next page

continued on Page 12

Capital Tax Calculation *continued from Page 11*

DOLLARS ONLY

D2. Calculation Do **not** complete this calculation if ss.69(2.1) election is filed

Taxable Capital From 470 on page 10 - + From 470 .

Determine aggregate taxable capital of an associated group (excluding financial institutions and corporations exempt from capital tax) and/or partnership having a permanent establishment in Canada

Names of associated corporations (excluding Financial Institutions and corporations exempt from Capital Tax) having a permanent establishment in Canada *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Taxable Capital
			+ 531 .
			+ 532 .
			+ 533 .

Aggregate Taxable Capital 470 + 531 + 532 + 533 , etc. - - - - - - - - - - - - - - - - - = 540 .

If 540 above is equal to or less than the TCD 503 on page 10, the corporation's Capital Tax for the taxation year, is NIL.

Enter NIL in 523 in section E below, as applicable.

If 540 above is greater than the TCD 503 on page 10, the corporation must compute its share of the TCD below in order to calculate its Capital Tax for the taxation year under Section E below.

From 470 . ÷ From 540 . X From 503 . = 541 .

Transfer to 542 *in Section E below*

Ss.69(2.1) Election Filed

☐ 591 (X if applicable) **Election filed**. *Attach a copy of Schedule 591 with this CT23 Return.* Proceed to **Section F** below.

SECTION E

This section applies if the corporation **is** a member of an associated group and/or partnership whose total **aggregate** Taxable Capital 540 above, exceeds the TCD 503 on page 10.

Complete the following calculation and transfer the amount from 523 to 543, and complete the return from that point.

\+ From 470 .
− 542 .
= 471 . X From 30 100.0000 % (Ontario Allocation) X From 516 0.2850 % (Capital Tax Rate) X 555 365 / 365 * (366 if leap year) = + 523 .

Total Capital Tax for the taxation year

Transfer to 543 *and complete the return from that point*

SECTION F

This section applies if a corporation is a member of an associated group and the associated group has filed a ss.69(2.1) election

\+ From 470 . X From 30 100.0000 % (Ontario Allocation) X From 516 0.2850 % (Capital Tax Rate) - - - - - - - = + 561 .

− Capital tax deduction from 995 relating to **your corporation's** Capital Tax deduction, on Schedule 591 - - − From 995 .

= 562 .

Total Capital Tax for the taxation year

Capital Tax - - - - - - - - 562 . X 555 365 / 365 * (366 if leap year) - - - - - = 563 .

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 14,991 .

Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)* - - - - - - - - - - − 546 .

Capital Tax 543 − 546 *(amount cannot be negative)* - - - - - - - - - - - - - - - - = 550 14,991 .

Transfer to Page 17

continued on Page 13

Capital Tax *continued from Page 12*

Calculation of Capital Tax for Financial Institutions

1.1 Credit Unions only

For taxation years commencing **after May 4, 1999** enter NIL in [550] on page 12, and complete the return from that point.

1.2 Other than Credit Unions

(Retain details of calculations for amounts in boxes [565] and [570]. Do not submit with this tax return.)

[565] _____ . x [567] _____ % x From [30] 100.0000 % x [555] 365 - - - - = + [569] _____ .

Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1

Capital Tax Rate (1) *(Refer to Guide)*

Ontario Allocation

Days in taxation year: * 365 (366 if leap year)

[570] _____ . x [571] _____ % x From [30] 100.0000 % x [555] 365 - - - - = + [574] _____ .

Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount

Capital Tax Rate (2) *(Refer to Guide)*

Ontario Allocation

Days in taxation year: * 365 (366 if leap year)

Capital Tax for Financial Institutions – other than Credit Unions (before Section 2) [569] + [574] - - = [575] _____ .

** If floating taxation year, refer to Guide.*

2. Small Business Investment Tax Credit

(Retain details of eligible investment calculation and, if claiming an investment in CSBIF, retain the original letter approving the credit issued in accordance with the Community Small Business Investment Fund Act. Do not submit with this tax return.)

Allowable Credit for Eligible Investments - - - -

DOLLARS ONLY

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

Net Income (loss) for federal income tax purposes, per federal T2 Schedule 1 ± 600 1,216,728.
Transfer to Page 15

Add:

Federal capital cost allowance	+ 601	753,260.
Federal cumulative eligible capital deduction	+ 602	
Ontario taxable capital gain	+ 603	
Federal non-allowable reserves. Balance beginning of year	+ 604	239,654.
Federal allowable reserves. Balance end of year	+ 605	
Ontario non-allowable reserves. Balance end of year	+ 606	1,137,013.
Ontario allowable reserves. Balance beginning of year	+ 607	
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	+ 608	
Federal resource allowance *(Refer to Guide)*	+ 609	
Federal depletion allowance	+ 610	
Federal foreign exploration and development expenses	+ 611	
Crown charges, royalties, rentals, etc. deducted for Federal purposes *(Refer to Guide)*	+ 617	

Management fees, rents, royalties and similar payments to non-arms' length non-residents ▼

Number of Days in Taxation Year

612 _____ x 5 / 12.5 x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 33 _____ ÷ Total Days: 73 365) = + 633 _____

612 _____ x 5 / 14 x (Days after Dec. 31, 2003: 34 365 ÷ Total Days: 73 365) = + 634 _____

Total add-back amount for Management fees, etc. 633 + 634 =	+ 613	
Federal Scientific Research Expenses claimed in year from line 460 of fed. form T661 excluding any negative amount in 473 from Ont. CT23 Schedule 161	+ 615	
Add any negative amount in 473 from Ont. CT23 Schedule 161	+ 616	
Federal allowable business investment loss	+ 620	
Total of other items not allowed by Ontario but allowed federally *(Attach schedule)*	+ 614	
Total of Additions 601 to 611 + 617 + 613 + 615 + 616 + 620 + 614	=	2,129,927. ▶ 640 2,129,927.

Transfer to Page 15

Deduct:

Ontario capital cost allowance (excludes amounts deducted under 675)	+ 650	753,260.
Ontario cumulative eligible capital deduction	+ 651	
Federal taxable capital gain	+ 652	
Ontario non-allowable reserves. Balance beginning of year	+ 653	239,654.
Ontario allowable reserves. Balance end of year	+ 654	
Federal non-allowable reserves. Balance end of year	+ 655	1,137,013.
Federal allowable reserves. Balance beginning of year	+ 656	
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) *(Retain calculations. Do not submit.)*	+ 657	
Ontario depletion allowance	+ 658	
Ontario resource allowance *(Refer to Guide)*	+ 659	
Ontario current cost adjustment *(Attach schedule)*	+ 661	
CCA on assets used to generate electricity from natural gas, alternative or renewable resources.	+ 675	
Subtotal of deductions for this page 650 to 659 + 661 + 675	681	2,129,927.

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 1,216,728 .

Total of Additions on page 14 - From = 640 2,129,927 .

Sub Total of deductions on page 14 - From = 681 2,129,927 .

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up
(***Applies*** only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

Capital Cost Allowance (Ontario) (CCA) on prescribed qualifying intellectual property deducted in the current taxation year - - - 662 .

ONTTI Gross-up deduction calculation:

Gross-up of CCA

[From 662 . x 100 / From 30 100.0000 Ontario Allocation] − From 662 . = 663 .

Workplace Child Care Tax Incentive (WCCT)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [665 . x 30 % x 100 / From 30 100.0000 Ontario allocation] = 666 .

Workplace Accessibility Tax Incentive (WATI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [667 . x 100 % x 100 / From 30 100.0000 Ontario allocation] = 668 .

Number of Employees accommodated 669

Ontario School Bus Safety Tax Incentive (OSBSTI)
(***Applies*** to the eligible acquisition of school buses purchased after May 4, 1999 and before January 1, 2006.) *(Refer to Guide)*

Qualifying expenditures: [670 . x 30 % x 100 / From 30 100.0000 Ontario allocation] = 671 .

Educational Technology Tax Incentive (ETTI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [672 . x 15 % x 100 / From 30 100.0000 Ontario allocation] = 673 .

Ontario allowable business investment loss - - - - - - - - - - - - - - - + 678 .

Ontario Scientific Research Expenses claimed in year in 477 **from Ont. CT23 Schedule 161** + 679 .

Amount added to income federally for an amount that was negative on federal form T661, line 454 or 455 (if filed after June 30, 2003) - - - - - - - - - + 677 .

Total of other deductions allowed by Ontario *(Attach schedule)* - - - - - - - - + 664 .

Total of Deductions 681 + 663 + 666 + 668 + 671 + 673 + 678 + 679 + 677 + 664 = 2,129,927 . ▶ 680 2,129,927 .

Net income (loss) for Ontario Purposes 600 + 640 − 680 - - - - - - - - - - - - - - - - - = 690 1,216,728 .

Transfer to Page 4

Continuity of Losses Carried Forward

DOLLARS ONLY

		Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year		700 (2)	710 (2)	720 (2)	730	740	750
Add:	Current year's losses (7)	701	711	721	731	741	751
	Losses from predecessor corporations (3)	702	712	722	732		752
Subtotal		703	713	723	733	743	753
Subtract:	Utilized during the year to reduce taxable income	704 (2)	715 (2) (4)	724 (2)	734 (2) (4)	744 (4)	754 (4)
	Expired during the year	705		725	735	745	
	Carried back to prior years to reduce taxable income (5)	706 (2) to Page 17	716 (2) to Page 17	726 (2) to Page 17	736 (2) to Page 17	746	
Subtotal		707	717	727	737	747	757
Balance at End of Year		709 (8)	719	729	739	749	759

Analysis of Balance at End of Year by Year of Origin

	Year of Origin (oldest year first) year month day	Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800	9th preceding taxation year 1998-12-31	817 (9)	860 (9)		850	870
801	8th preceding taxation year 1999-12-31	818 (9)	861 (9)		851	871
802	7th preceding taxation year 2000-12-31	819 (9)	862 (9)		852	872
803	6th preceding taxation year 2001-12-31	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:
  1) the first day of the taxation year after the loss year,
  2) the day on which the corporation's return for the loss year is delivered to the Minister, or
  3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
- If a loss is being carried back to a **predecessor corporation**, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses

	Predecessor Ontario Corporation's Tax Account No. (MOF)	Taxation Year Ending year month day	Non-Capital Losses	Total Capital Losses	Farm Losses	Restricted Farm Losses
Total amount of loss			910	920	930	940
Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income						
i) 3rd preceding	901	2004-12-31	911	921	931	941
ii) 2nd preceding	902	2005-12-31	912	922	932	942
iii) 1st preceding	903	2006-12-31	913	923	933	943
Total loss to be carried back			From 706	From 716	From 726	From 736
Balance of loss available for carry-forward			919	929	939	949

Summary

Income Tax	+ From 230 or	320	169,552 .
Corporate Minimum Tax	+ From	280	.
Capital Tax	+ From	550	14,991 .
Premium Tax	+ From	590	.
Total Tax Payable	=	950	184,543 .
Subtract: Payments	–	960	166,080 .
Capital Gains Refund (s.48)	–	965	.
Qualifying Environmental Trust Tax Credit *(Refer to Guide)*	–	985	.
Specified Tax Credits *(Refer to Guide)*	–	955	.
Other, specify Federal tax	–		-288,777 .
Balance	=	970	307,240 .
If payment due Enclosed *		990	307,240 .
If overpayment: Refund *(Refer to Guide)*	=	975	.
Apply to (year month day)		980	.

(Includes credit interest)

* Make your cheque (drawn on a Canadian financial institution) or a money order in Canadian funds, payable to the **Minister of Finance** and print your Ontario Corporation's Tax Account No. (MOF) on the back of cheque or money order. *(Refer to Guide for other payment methods.)*

Certification

I am an authorized signing officer of the corporation. I certify that this CT23 return, including all schedules and statements filed with or as part of this CT23 return, has been examined by me and is a true, correct and complete return and that the information is in agreement with the books and records of the corporation. I further certify that the financial statements accurately reflect the financial position and operating results of the corporation as required under section 75 of the *Corporations Tax Act*. The method of computing income for this taxation year is consistent with that of the previous year, except as specifically disclosed in a statement attached.

Name *(please print)*

SIGN HERE

FLORENCE THIESSEN

Title

VICE-PRESIDENT-TREASURER

Full Residence Address

Signature	Date
	2008-06-13

Note: Section 76 of the *Corporations Tax Act* provides penalties for making false or misleading statements or omissions.

Attached Schedule with Total

Loans and advances to unrelated corporations

Title Loans and advances to unrelated corporations

Description	Amount
prepaid expenses	19,655 00
Total	19,655 00

Attached Schedule with Total

Other reserves not allowed as deductions for income tax purposes (Attach schedule) (Int.B. 3012R)

Title Other reserves not allowed as deductions for income tax purposes (Attach

Description	Amount
Ontario schedule 8 UCC Ending balance	10,779,671 00
NBV	-6,961,518 00
Post-employment benefits	84,853 00
Regulatory liabilities,net	1,052,160 00
Total	4,955,166 00

Corporate Minimum Tax (CMT)

CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	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	60,890
Subtract (to the extent reflected in net income/loss):					
Provision for recovery of income taxes / benefit of current income taxes	+	2101			
Provision for deferred income taxes (credits) / benefit of future income taxes	+	2102			
Equity income from corporations	+	2103			
Share of partnership(s)/joint venture(s) income	+	2104			
Dividends received/receivable deductible under fed.s.112	+	2105	424		
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)	+	2109			
Subtotal	=		424	– 2110	424
Add (to extent reflected in net income/loss):					
Provision for current taxes / cost of current income taxes	+	2111	451,827		
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	=		451,827	+ 2116	451,827
Add/Subtract:					
Amounts relating to s.57.9 election/regulations for disposals etc. of property for current/prior years					
** Fed.s.85	+	2117		or – 2118	
** Fed.s.85.1	+	2119		or – 2120	
** Fed.s.97	+	2121		or – 2122	
** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years	+	2123		or – 2124	
** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/prior years	+	2125		or – 2126	
** Amounts relating to s.57.10 election/regulations for replacement re fed.s13(4), 14(6) and 44 for current/prior years	+	2127		or – 2128	
Interest allowable under ss.20(1)(c) or (d) of ITA to the extent not otherwise deducted in determining CMT adjusted net income				– 2150	
Capital gains on eligible donations of publicly-listed securities and ecologically sensitive land made after May 1, 2006 (to the extent reflected in net income/loss)				– 2155	
Subtotal (Additions)	=				+ 2129
Subtotal (Subtractions)	=				– 2130
** Other adjustments					± 2131
Subtotal ± 2100 – 2110 + 2116 + 2129 – 2130 ± 2131					= 2132 512,293
** 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 512,293
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 512,293

Transfer to CMT Base on Page 8 of the CT23 or Page 6 of the CT8

Corporate Minimum Tax (CMT)

CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	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		=	▶	+ 2207	
Adjustments (attach schedule)				± 2208	
CMT losses available	2201 + 2207 ± 2208			= 2209	
Subtract:	Pre-1994 loss utilized during the year to reduce adjusted net income	+ 2210			
	Other eligible losses utilized during the year to reduce adjusted net income NOTE (4)	+ 2211			
	Losses expired during the year	+ 2212			
Subtotal		=	▶	− 2213	
Balances at End of Year NOTE (5)	2209 − 2213			= 2214	

Notes:

(1) Pre-1994 CMT loss (see s.57.1(1)) should be included in the balance at beginning of the year. Attach schedule showing computation of pre-1994 CMT loss.

(2) Where acquisition of control of the corporation has occurred, the utilization of CMT losses can be restricted. (see s.57.5(3) and a 57.5(7))

(3) Include and indicate whether CMT losses are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.57.5(8) and s.57.5(9))

(4) CMT losses must be used to the extent of the lesser of the adjusted net income 2134 and CMT losses available 2209.

(5) Amount in 2214 must equal sum of 2270 + 2290.

Part 3: Analysis of CMT Losses Year End Balance by Year of Origin

For a pre-1994 loss, use the date of the last taxation year end before your corporation's first taxation year commencing after 1993.

	Year of Origin (oldest year first) year month day	CMT Losses of Corporation	CMT Losses of Predecessor Corporations
2240	9th preceding taxation year 1998-12-31	2260	2280
2241	8th preceding taxation year 1999-12-31	2261	2281
2242	7th preceding taxation year 2000-12-31	2262	2282
2243	6th preceding taxation year 2001-12-31	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

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	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 1998-12-31	2360	2380
2341	8th preceding taxation year 1999-12-31	2361	2381
2342	7th preceding taxation year 2000-12-31	2362	2382
2343	6th preceding taxation year 2001-12-31	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	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	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	1997-12-31					
9th Prior Year	1998-12-31					
8th Prior Year	1999-12-31					
7th Prior Year	2000-12-31					
6th Prior Year	2001-12-31					
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
1997-12-31						
1998-12-31						
1999-12-31						
2000-12-31						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	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
1997-12-31						
1998-12-31						
1999-12-31						
2000-12-31						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	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	1997-12-31					
9th Prior Year	1998-12-31					
8th Prior Year	1999-12-31					
7th Prior Year	2000-12-31					
6th Prior Year	2001-12-31					
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
1997-12-31						
1998-12-31						
1999-12-31						
2000-12-31						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
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
1997-12-31						
1998-12-31						
1999-12-31						
2000-12-31						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

Ontario

Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Paid-Up Capital: Loans and Advances

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	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)

Current portion of customer deposits	+	215,289
Due to shareholder	+	
Customer deposits	+	
Note payable	+	5,046,753
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
Total *Transfer to* 353 *of the CT23*	=	5,262,042

Ontario

Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Ontario Charitable Donations and Gifts

Schedule 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	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	+	5,220 E		
Subtotal D + E	=	5,220	▶	5,220 F
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)			–	G
Total donations available **C + F – G**			=	5,220 H
Deduct: Amount applied against taxable income (amount **U**, Part 2)			–	5,220 U
Charitable donations closing balance			=	I

Part 2 – Maximum Deduction Calculation for Donations

Ontario net income for tax purposes multiplied by 75%			=	912,546 J
Note: *For credit unions the Ontario net income for tax purposes is the amount before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.*				
Ontario taxable capital gains arising in respect of gifts of capital property	+	K		
Ontario taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01) ITA	+	L		

Add the lesser of:

1. The amount of the recapture of capital cost allowance in respect of charitable gifts — M
2. **The lesser of:**
   - 2a. Proceeds of dispositions less outlays and expenses — N
   - 2b. The capital cost — O
   - The lesser of **N** and **O** — ▶ P
   - The lesser of **M** and **P** — ▶ + Q
   - **Subtotal K + L + Q** = R
   - 25% X R = S
   - **Maximum deduction allowable J + S** = 912,546 T

Claim for charitable donations (not exceeding the lesser of **H** from Part 1, **T** and net income for tax purposes) 5,220 U

Enter in 1 *of the CT23*

Ontario Charitable Donations and Gifts

Schedule 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	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			1,211,508 V
2. **Lesser of:**			
2a. Ontario Net Income for the taxation year	1,216,728 W		
2b. Gifts made in the taxation year or any of the five preceding taxation years to Her Majesty in Right of Ontario, an Ontario Crown Agency or an Ontario Crown Foundation	X		
The lesser of **W** and **X**		▶	Y
Maximum deduction allowable the lesser of **V** and **Y**			Z

Transfer to 2 *of the CT23*

Part 5 – Gifts to Canada or a province other than Ontario

Gifts to Canada or a province other than Ontario at the end of the preceding year		+		
Deduct: Gifts to Canada or a province other than Ontario expired after five taxation years		–		
Gifts to Canada or a province other than Ontario at the beginning of the taxation year		=		
Add: Gifts to Canada or a province other than Ontario transferred on amalgamation or wind-up of a subsidiary		+		
Total current year Gifts to Canada or a province other than Ontario *(Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date.)*		+		
Subtotal		=	▶	
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)			–	
Total gifts to Canada or a province other than Ontario available			=	
Deduct: Amount applied against taxable income			–	
Gifts to Canada or a province other than Ontario closing balance			=	

Ontario Charitable Donations and Gifts

Schedule 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	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					
2001-12-31					
Totals					

Ontario

Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Ontario Capital Cost Allowance
Schedule 8

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	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	9,765,482	3,381		0	9,768,863	1,691	9,767,172	4	0	0	390,687	9,378,176
8	923,848	22,715		38,386	908,177		908,177	20	0	0	181,635	726,542
10	360,455	60,580		0	421,035	30,290	390,745	30	0	0	117,224	303,811
10	24,508			0	24,508		24,508	30	0	0	7,352	17,156
17	11,975			0	11,975		11,975	8	0	0	958	11,017
45	17,982	19,459		0	37,441	9,730	27,711	45	0	0	12,470	24,971
12	3,101	52,270		0	55,371	26,135	29,236	100	0	0	29,236	26,135
47		299,280		0	299,280	149,640	149,640	8	0	0	11,971	287,309
50		6,281		0	6,281	3,141	3,140	55	0	0	1,727	4,554
Totals	11,107,351	463,966		38,386	11,532,931	220,627	11,312,304					10,779,671
											753,260	

Enter in boxes 650 . . . . 650 . . . . 650 on the CT23.

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule. See Regulation 1100(2) and (2.2) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

Ontario

Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Ontario Continuity of Reserves
Schedule 13

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	2007-12-31

For use by a corporation to provide a continuity of all reserves claimed which are allowed for tax purposes.

Part 1 – Capital gains reserves

	Description of property	Ontario balance at the beginning of the year $	Transfer on amalgamation or wind-up of subsidiary $	Add	Deduct	Ontario balance at the end of the year $
1						
	Totals	A	B			C

The total capital gains reserve at the beginning of the taxation year **A** plus the total capital gains reserve transfer on amalgamation or wind-up of subsidiary **B**, should be entered on Schedule 6; and the total capital gains reserve at the end of the taxation year **C**, should also be entered on Schedule 6.

Part 2 – Other reserves

Description	Ontario balance at the beginning of the year $	Transfer on amalgamation or wind-up of subsidiary $	Add	Deduct	Ontario balance at the end of the year $
Reserve for doubtful debts					
Reserve for undelivered goods and services not rendered					
Reserve for prepaid rent					
Reserve for December 31, 1995 income					
Reserve for refundable containers					
Reserve for unpaid amounts					
Other tax reserves					
Totals	D	E			F

The amount from **D** plus the amount from **E** should be entered in [607] of the CT23.
The amount from **F** should be entered in [654] of the CT23.

Part 3 – Continuity of non-deductible reserves

Reserve	Ontario opening balance	Transfers	Ontario additions	Ontario deductions	Other adjustments	Ontario closing balance
Recoveries of regulatory assets	-259,998		197,602			-62,396
Settlement variance	414,664		699,892			1,114,556
Post-employment benefits	84,988			135		84,853
Reserves from Part 2						
Totals	239,654		897,494	135		1,137,013

Enter in box [653] *of the CT23* — *Enter in box* [606] *of the CT23*

Ontario

Ministry of Revenue
Corporations Tax
33 King St. West
PO Box 622
Oshawa ON L1H 8H6

Authorizing or Cancelling a Representative

Complete this form to:

- **authorize** the release of confidential information about the Corporations Tax, Mining Tax or Electricity Act account(s) to the representative named below.
- **cancel** an existing authorization.

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CENTRE WELLINGTON HYDRO LTD.	1800241	2007-12-31

Part 1 Client Information

Legal Name: CENTRE WELLINGTON HYDRO LTD.
Phone number: (519) 843-2900

Mailing address
Apt./Suite/Unit no. Street number and name / PO Box, RR: 730 GARTSHORE STREET PO BOX 217
City: FERGUS
Province/Territory: ON
Postal code: N1M 2W8

This authorization applies to the following statute(s) and account number(s).

- [X] Corporations Tax Act — 1800241
- [ ] Mining Tax Act
- [ ] Electricity Act

Part 2 Authorize the release of information to a representative

Name of representative (If a firm, name of firm.)
Last: KPMG LLP
First:
Phone number: (519) 747-8800
Fax number: (519) 747-8890

Mailing address
Apt./Suite/Unit no. Street number and name / PO Box, RR: 115 King Street South 2nd Floor
City: WATERLOO
Province/Territory: ON
Postal code: N2J 5A3

If your representative is a firm, and you want a specific person in the firm to represent you, state their name and title.
If you do not identify a specific individual in the firm, you are authorizing the Ministry of Finance to deal with anyone from that firm.

Name of person in firm
Last:
First:
Title:

Part 3 Authorization scope and applicable years

- [X] Representative to **deal fully** on your behalf with the Ministry of Finance.

or

- [ ] Representative to **deal in a limited manner** on your behalf, for matters specified here. (e.g., account inquiry, applications, annual returns, payments, etc.) ▼

- [X] Representative to act for **all years**, including all previous and future years.

or

- [ ] Representative to act for **specific year or years** (describe). ▼

Part 4 Cancel the release of information to a representative

Name of representative (If a firm, name of firm.)
Last:
First:

If your representative is an individual within a firm, state their name and title.

Name of person in firm
Last:
First:
Title:

Part 5 Signature *This form will not be accepted unless it is completed fully, signed and dated.*

I authorize the Ministry of Finance to:

- release confidential information about the tax accounts specified in Part 1 and to deal with the representative named in Part 2 in the manner described in Part 3; and/or
- cancel an existing authorization as described in Part 4.

Name
Last: THIESSEN
First: FLORENCE
Title / Relationship to Corporation: VICE-PRESIDENT-TREASURER
Phone number: (519) 843-2900

Signature: Florence L Thiessen
Date: 2008-06-17

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in 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).

Identification

Business Number (BN) 001 86547 0769 RC0001

Corporation's name

002 CENTRE WELLINGTON HYDRO LTD.

Has the corporation changed its name since the last time you filed your T2 return? 003 1 Yes [ ] 2 No [X]

If **yes**, do you have a copy of the articles of amendment? ***(Do not submit)*** 004 1 Yes [ ] 2 No [ ]

Address of head office

Has this address changed since the last time you filed your T2 return? 010 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 011 to 018)

011 730 GARTSHORE STREET

012 PO BOX 217

City	Province, territory, or state
015 FERGUS	016 ON
Country (other than Canada)	**Postal code/Zip code**
017	018 N1M 2W8

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? 020 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 021 to 028)

021 c/o

022 730 GARTSHORE STREET

023 PO BOX 217

City	Province, territory, or state
025 FERGUS	026 ON
Country (other than Canada)	**Postal code/Zip code**
027	028 N1M 2W8

Location of books and records

Has the location of books and records changed since the last time you filed your T2 return? 030 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 031 to 038)

031 730 GARTSHORE STREET

032 PO BOX 217

City	Province,territory, or state
035 FERGUS	036 ON
Country (other than Canada)	**Postal code/Zip code**
037	038 N1M 2W8

040 Type of corporation at the end of the tax year

1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 YYYY MM DD

To which tax year does this return apply?

Tax year start	Tax year-end
060 2007-01-01	061 2007-12-31
YYYY MM DD	YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? 063 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired 065 YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:

Incorporation? 070 1 Yes [ ] 2 No [X]

Amalgamation? 071 1 Yes [ ] 2 No [X]

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? 072 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? 078 1 Yes [ ] 2 No [X]

Is the corporation a resident of Canada?

080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and **complete and attach** Schedule 97.

081

Is the non-resident corporation claiming an exemption under an income tax treaty? 082 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each *Yes* response, **attach** to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	150		9
Is the corporation an associated CCPC?	160		23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207	X	7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210		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	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation a member of a related group with one or more members subject to gross Part I.3 tax?	236		36
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177

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	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

* We do not print this schedule.

Additional information

Is the corporation inactive?	280	1 Yes	2 No X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281	1 Yes	2 No X

What is the corporation's major business activity? 282
(Only complete if **yes** was entered at line 281)

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale 2 Retail

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	HYDRO ELECTRICITY	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes	2 No X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes	2 No X

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.		300		1,216,728 A
Deduct: Charitable donations from Schedule 2		311	5,220	
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	424	
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		5,644 ▶	5,644 B
	Subtotal (amount A **minus** amount B) (if negative, enter "0")			1,211,084 C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions		355		D
Taxable income (amount C **plus** amount D)		360		1,211,084
Income exempt under paragraph 149(1)(t)		370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				1,211,084 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** 958,496 A

Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 3 times the amount on line 636**, and **minus** any amount that, because of federal law, is exempt form Part I tax . . . . . **405** 1,211,084 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 / Number of days in the tax year) = ... 1

400,000 x (Number of days in the tax year after 2006 / Number of days in the tax year) 365/365 = ... 400,000 2

Add amounts at lines 1 and 2 400,000 4

Business limit (see notes 1 and 2 below) . . . . . **410** 400,000 C

Notes:
1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 400,000 x **415** *** 6,722 / 11,250 D = ... 239,004 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . **425** 160,996 F

Small business deduction

Amount A, B, C, or F whichever is the least 160,996 x (Number of days in the tax year before January 1, 2008 / Number of days in the tax year) 365/365 x 16 % = 25,759 5

Amount A, B, C, or F whichever is the least 160,996 x (Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year) /365 x 17 % = 6

Amount A, B, C, or F whichever is the least 160,996 x (Number of days in the tax year after December 31, 2008 / Number of days in the tax year) /365 x 17 % = 7

Total of amounts 5, 6, and 7 – enter on line 9 **430** 25,759 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 / Number of days in the tax year) /365 x 3 % = I

Amount H x (Number of days in the tax year in 2006 / Number of days in the tax year) /365 x 5 % = J

Amount H x (Number of days in the tax year in 2007 / Number of days in the tax year) 365/365 x 7 % = K

Resource deduction – total of amounts I, J and K . . . . . **438** L
Enter amount L on line 10.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360			1,211,084 A
Amount Z1 from Part 9 of Schedule 27		B	
Amount QQ from Part 13 of Schedule 27		C	
Taxable resource income from line 435		D	
Amount used to calculate the credit union deduction (from Schedule 17)		E	
Amount from line 400, 405, 410, or 425, whichever is the least	160,996	F	
Aggregate investment income from line 440	257,808	G	
Total of amounts B, C, D, E, F, and G	418,804 ▶		418,804 H
Amount A **minus** amount H (if negative, enter "0")			792,280 I

Amount I	792,280	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365	x	7 %	=	55,460 J
Amount I	792,280	x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	K
Amount I	792,280	x	Number of days in the tax year after December 31, 2008 and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=	K1
Amount I	792,280	x	Number of days in the tax year after December 31, 2009 and before January 1, 2011 / Number of days in the tax year	/ 365	x	10 %	=	K2

General tax reduction for Canadian-controlled private corporations – total of amounts J, K, K1, and K2 . . . . . 55,460 L
Enter amount L on line 638.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation, and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 (for tax years starting after May 1, 2006, amount Z)			M
Amount Z1 from Part 9 of Schedule 27		N	
Amount QQ from Part 13 of Schedule 27		O	
Taxable resource income from line 435		P	
Amount used to calculate the credit union deduction (from Schedule 17)		Q	
Total of amounts N, O, P, and Q	▶		R
Amount M **minus** amount R (if negative, enter "0")			S

Amount S		x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365	x	7 %	=	T
Amount S		x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	U
Amount S		x	Number of days in the tax year after December 31, 2008 and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=	U1
Amount S		x	Number of days in the tax year after December 31, 2009 and before January 1, 2011 / Number of days in the tax year	/ 365	x	10 %	=	U2

General tax reduction – total of amounts T, U, U1, and U2 V
Enter amount V on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income (from Schedule 7)	440	257,808	x 26 2 / 3 % =		68,749 A
Foreign non-business income tax credit from line 632					
Deduct:					
Foreign investment income (from Schedule 7)	445		x 9 1 / 3 % =		
			(if negative, enter "0")		B
Amount A **minus** amount B (if negative, enter "0")					68,749 C
Taxable income from line 360				1,211,084	
Deduct:					
Amount from line 400, 405, 410, or 425, whichever is the least		160,996			
Foreign non-business income tax credit from line 632			x 25 / 9 =		
Foreign business income tax credit from line 636			x 3 =		
		160,996		160,996	
				1,050,088	
				x 26 2 / 3 % =	280,023 D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780)				288,636	
Deduct: Corporate surtax from line 600				13,564	
Net amount				275,072	275,072 E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least	450				68,749 F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	460	562		
Deduct: Dividend refund for the previous tax year	465			
		562		562 G
Add the total of:				
Refundable portion of Part I tax from line 450 above		68,749		
Total Part IV tax payable from Schedule 3		141		
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480			
		68,890		68,890 H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H	485			69,452

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3		x 1 / 3	I
Refundable dividend tax on hand at the end of the tax year from line 485 above			69,452 J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784)			

Part I tax

Base amount of Part I tax – taxable income (line 360 or amount Z, whichever applies) **multiplied** by 38.00 % . . . . . 550 460,212 A

Corporate surtax calculation

Base amount from line A above	460,212	1
Deduct:		
10 % of taxable income (line 360 or amount Z, whichever applies)	121,108	2
Investment corporation deduction from line 620 below		3
Federal logging tax credit from line 640 below		4
Federal qualifying environmental trust tax credit from line 648 below		5
For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:		
28.00 % of taxable income from line 360 — a		
28.00 % of taxed capital gains — b		6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F) — c		
Total of lines 2 to 6	121,108	7
Net amount (line 1 **minus** line 7)	339,104	8

Corporate surtax*

Line 8 339,104 x (Number of days in the tax year before January 1, 2008 / Number of days in the tax year) 365 / 365 x 4 % = 600 13,564 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		257,808	i
Taxable income from line 360	1,211,084		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least	160,996		
Net amount	1,050,088 ▶	1,050,088	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . . 604 17,187 D

Subtotal (**add** lines A, B, C, and D) 490,963 E

Deduct:

Small business deduction from line 430		25,759	9
Federal tax abatement	608	121,108	
Manufacturing and processing profits deduction from Schedule 27	616		
Investment corporation deduction	620		
(taxed capital gains 624)			
Additional deduction – credit unions from Schedule 17	628		
Federal foreign non-business income tax credit from Schedule 21	632		
Federal foreign business income tax credit from Schedule 21	636		
Resource deduction from line 438			10
General tax reduction for CCPCs from amount L	638	55,460	
General tax reduction from amount V	639		
Federal logging tax credit from Schedule 21	640		
Federal political contribution tax credit	644		
Federal political contributions 646			
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652		
Subtotal		202,327 ▶	202,327 F

Part I tax payable – Line E **minus** line F . . . . . 288,636 G
Enter amount G on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	288,636
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	141
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		288,777

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 Ontario
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Québec, Ontario, and Alberta)	760	
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765	
Total tax payable	770	288,777 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	B

Refund code 894 Overpayment

Balance (line A **minus** line B) 288,777

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid 288,777

Enclosed payment 898 288,777

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 SIGN HERE number

914 Institution number 918

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 THIESSEN (Last name in block letters) 951 FLORENCE (First name in block letters) 954 VICE-PRESIDENT-TREASURER (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2008-06-13 (Date (yyyy/mm/dd)) Signature of the authorized signing officer of the corporation

956 (519) 843-2900 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 ☐

Canada Revenue Agency / Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES — SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
CENTRE WELLINGTON HYDRO LTD.	86547 0769 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				60,890 A
Add:				
Provision for income taxes – current	101	451,827		
Interest and penalties on taxes	103	106		
Amortization of tangible assets	104	589,402		
Charitable donations and gifts from Schedule 2	112	5,220		
Non-deductible meals and entertainment expenses	121	3,570		
Reserves from financial statements – balance at the end of the year	126	1,137,013		
Subtotal of additions		2,187,138	▶	2,187,138
Other additions:				
Miscellaneous other additions:				
Subtotal of other additions	199	0	▶	0
Total additions	500	2,187,138	▶	2,187,138
Deduct:				
Gain on disposal of assets per financial statements	401	38,386		
Capital cost allowance from Schedule 8	403	753,260		
Reserves from financial statements – balance at the beginning of the year	414	239,654		
Subtotal of deductions		1,031,300	▶	1,031,300
Other deductions:				
Miscellaneous other deductions:				
Total	394			
Subtotal of other deductions	499	0	▶	0
Total deductions	510	1,031,300	▶	1,031,300
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				1,216,728

* For reference purposes only

T2 SCH 1 E (08)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 2

CHARITABLE DONATIONS AND GIFTS

Name of corporation	Business Number	Tax year-end Year Month Day
CENTRE WELLINGTON HYDRO LTD.	86547 0769 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)
Big brothe/ sister	1,000
Fergus Lion Club	1,000
Horticultureal Society	300
Fergus Firefighters	300
Fergus truck show	270
Fergus Scottish Festival	1,500
Upper grand learning foundation	200
Food bank	650
Subtotal	5,220
Add: Total donations of less than $100 each	
Total donations in current tax year	5,220

		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) 5,220	210			
Subtotal (line 250 **plus** line 210)		5,220	5,220	5,220
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)	255			
Total charitable donations available		5,220 A	5,220	5,220
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	5,220	5,220	5,220
Charitable donations closing balance	280			

Amounts carried forward – Charitable donations

Year of origin:		Federal	Quebec	Alberta
1st prior year	2006			
2nd prior year	2005			
3rd prior year	2004			
4th prior year	2003			
5th prior year	2002			
6th prior year *	2001			
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 % ..... 912,546 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) 912,546 J

Maximum allowable deduction for charitable donations (enter amount A from Part 1, amount J, or net income for tax purposes, whichever is less) ..... 5,220 K

* For credit unions, this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts to Canada, a province, or a territory

Gifts to Canada, a province, or a territory at the end of the previous tax year .....

Deduct: Gifts to Canada, a province, or a territory expired after five tax years .... 339 ____

Gifts to Canada, a province, or a territory at the beginning of the tax year ..... 340 ____ ▶ ____

Add: Gifts to Canada, a province, or a territory transferred on an amalgamation or the windup of a subsidiary ..... 350 ____

Total current-year gifts made to Canada, a province, or a territory * ..... 310 ____

Subtotal (line 350 **plus** line 310) ____

Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004) ..... 355 ____

Total gifts to Canada, a province, or a territory available .....

Deduct: Amount applied against taxable income (enter this amount on line 312 of the T2 return). ..... 360 ____

Gifts to Canada, a province, or a territory closing balance ..... 380 ____

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

Part 4 – Gifts of certified cultural property

		Federal	Quebec	Alberta
Gifts of certified cultural property at the end of the previous tax year				
Deduct: Gifts of certified cultural property expired after five tax years	439			
Gifts of certified cultural property at the beginning of the tax year	440			
Add: Gifts of certified cultural property transferred on an amalgamation or the windup of a subsidiary	450			
Total current-year gifts of certified cultural property	410			
Subtotal (line 450 **plus** line 410)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	455			
Total gifts of certified cultural property available				
Deduct: Amount applied against taxable income (enter this amount on line 313 of the T2 return)	460			
Gifts of certified cultural property closing balance	480			

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Quebec	Alberta
1st prior year	2006			
2nd prior year	2005			
3rd prior year	2004			
4th prior year	2003			
5th prior year	2002			
6th prior year *	2001			
Total				

* These donations expired in the current year.

Part 5 – Gifts of certified ecologically sensitive land

		Federal	Quebec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year				
Deduct: Gifts of certified ecologically sensitive land expired after five tax years	539			
Gifts of certified ecologically sensitive land at the beginning of the tax year	540			
Add: Gifts of certified ecologically sensitive land transferred on an amalgamation or the windup of a subsidiary	550			
Total current-year gifts of certified ecologically sensitive land	510			
Subtotal (line 550 **plus** line 510)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	555			
Total gifts of certified ecologically sensitive land available				
Deduct: Amount applied against taxable income (enter this amount on line 314 of the T2 return)	560			
Gifts of certified ecologically sensitive land closing balance	580			

Amounts carried forward – Gifts of certified ecologically sensitive land

Year of origin:		Federal	Quebec	Alberta
1st prior year	2006			
2nd prior year	2005			
3rd prior year	2004			
4th prior year	2003			
5th prior year	2002			
6th prior year *	2001			
Total				

* These donations expired in the current year.

Part 6 – Additional deduction for gifts of medicine

		Federal	Quebec	Alberta
Additional deduction for gifts of medicine at the end of the previous tax year				
Deduct: Additional deduction for gifts of medicine expired after five tax years	639			
Additional deduction for gifts of medicine at the beginning of the tax year	640			
Add: Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650			
Additional deduction for gifts of medicine for the current year:				
Proceeds of disposition	602	1	1	1
Cost of gifts of medicine	601	2	2	2
Subtotal (line 1 **minus** line 2)		3	3	3
Line 3 **multiplied** by 50 %		4	4	4
Eligible amount of gifts	600	5	5	5

Federal

A _____ x (B _____ / C) = Additional deduction for gifts of medicine for the current year **610** _____

Quebec

A _____ x (B _____ / C) = Additional deduction for gifts of medicine for the current year _____

Alberta

A _____ x (B _____ / C) = Additional deduction for gifts of medicine for the current year _____

where:

A is the **lesser** of line 2 and line 4

B is the eligible amount of gifts (line 600)

C is the proceeds of disposition (line 602)

Subtotal (line 650 **plus** line 610)				
Deduct: Adjustment for an acquisition of control	655			
Total additional deduction for gifts of medicine available				
Deduct: Amount applied against taxable income (enter this amount on line 315 of the T2 return)	660			
Additional deduction for gifts of medicine closing balance	680			

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Quebec	Alberta
1st prior year	2006			
2nd prior year	2005			
3rd prior year	2004			
4th prior year	2003			
5th prior year	2002			
6th prior year *	2001			
Total				

* These donations expired in the current year.

Canada Revenue Agency / Agence du revenu du Canada

DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year end Year Month Day
CENTRE WELLINGTON HYDRO LTD.	86547 0769 RC0001	2007-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid for purposes of a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act*.
- A recipient corporation is connected with a payer corporation at any time in a taxation year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the sections about Schedule 3 in the *T2 Corporation Income Tax Guide*.
- "X" under column A if dividend received from a foreign source (connected corporation only).
- "X" under column B if the payer corporation is connected.
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible to a 45% gross up for the purpose of the dividend tax credit for individuals.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received during the taxation year

Do not include dividends received from foreign non-affiliates.

	Name of payer corporation (Use only one line per corporation, abreviating its name if necessary) 200	A	Complete if payer corporation is connected B 205	C Business Number 210	D Taxation year end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends were paid YYYY/MM/DD 220	E Non-taxable dividend under section 83 230
1	Sun Life					
2						
					Total	

Note: If your corporation's taxation year end is different than that of the connected payer corporation, your corporation could have received dividends from more than one taxation year of the payer corporation. If so, use a separate line to provide the information for each taxation year of the payer corporation.

	F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d) 240	F1	F2	If payer corporation is not connected, leave these columns blank. G Total taxable dividends paid by connected payer corporation 250	H Dividend refund of the connected payer corporation 260	I Part IV tax before deductions F x 1 / 3 * 270
1	424	424	1			141
2						
Total (enter amount of column F on line 320 of the T2 return)	424	424				141 J

For dividends received from connected corporations: Part IV tax equals: $\frac{\text{Column F x Column H}}{\text{Column G}}$

* Life insurers are not subject to Part IV tax on subsection 138(6) dividends.
Public corporations (other than subject corporations) do not need to calculate Part IV tax.

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1)		141
Deduct:		
Part IV.I tax payable on dividends subject to Part IV tax	320	
	Subtotal	141
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	141

Part 3 – Taxable dividends paid in the taxation year for purposes of a dividend refund

	A	B	C	D
	Name of connected recipient corporation 400	Business Number 410	Taxation year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD 420	Taxable dividends paid to connected corporations 430
1				

Note
If your corporation's taxation year end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one taxation year of the recipient corporation. If so, use a separate line to provide the information for each taxation year of the recipient corporation.

Total

Total taxable dividends paid in the taxation year to other than connected corporations	450	
Total taxable dividends paid in the taxation year for the purposes of a dividend refund (total of column D above plus line 450)	460	

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	
Other dividends paid in the taxation year (total of 510 to 540)		
Total dividends paid in the taxation year	500	
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		

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 7

CALCULATION OF AGGREGATE INVESTMENT INCOME AND ACTIVE BUSINESS INCOME

Name of corporation	Business Number	Tax year end Year Month Day
CENTRE WELLINGTON HYDRO LTD.	86547 0769 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		001	002	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)				A
Eligible portion of allowable capital losses for the year (including allowable business investment losses)		009	012	B
Net capital losses of other years claimed on line 332 on the T2 return			022	C
Total of amounts B and C				D
Amount A **minus** amount D (if negative, enter "0")				E
Total income from property (in box 32 include income from a specified investment business carried on in Canada other than income from a source outside Canada)				
Taxable dividends	424		424	
Other property income	257,808		257,808	
Total income from property	258,232	019	032 258,232	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)	424	049	062 424	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	424		424	K
Amount F **minus** amount K	257,808		257,808	L
Total of amount E **plus** amount L	257,808		257,808	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")	257,808	079 L	092 O 257,808	

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	424		424
Less: Expenses related to such dividends			
Total expenses			
Net taxable dividends	424		424

Part 3 – Specified partnership income

A	B	C
Partnership name 200	Total income (loss) of partnership from an active business 300	Corporation's share of amount in column B 310

D	E	F	G	H	I
Adjustments [add prior-year reserves under subsection 34.2(5), and deduct expenses incurred to earn partnership income, including any reserve under subsection 34.2(4)] 315	Corporation's income (loss) of the partnership (column C **plus** column D) 320	Number of days in the partnership's fiscal period 325	Prorated business limit (column C ÷ column B) × [business limit* × (column F ÷ 365)] (if column C is negative, enter "0")** 330	Column E **minus** column G (if negative, enter "0")	Lesser of columns E and G (if column E is negative, enter "0") 340
Total 350				**Total** 385	360

Corporation's losses for the year from an active business carried on in Canada (other than as a member of a partnership) – enter as a positive amount 370

Specified partnership loss of the corporation for the year – enter as a positive amount (total of all negative amounts in column E) 380

Total of lines 370 and 380 . . . . . ▶ J

Amount at line 385 or line J, whichever is less 390

Specified partnership income (line 360 **plus** line 390) 400

* Use one of the following business limits to calculate column G, whichever applies:

- $250,000 if the corporation's tax year ends in 2004;
- $300,000 if the corporation's tax year ends in 2005 or 2006; or
- $400,000 if the corporation's tax year ends after 2006.

** When a partnership carries on more than one business, one of which generates income and another of which realizes a loss, the loss is not netted against the partnership's income.

Part 4 – Determination of partnership income

Corporation's share of partnership income from active businesses carried on in Canada after deducting related expenses – from line 350 above (if the net amount is negative, enter "0" on line O) . . . . . K

Add: Specified partnership loss (from line 380 above) L

Subtotal M

Deduct: Specified partnership income (from line 400 above) . . . . . N

Partnership income (enter on line S below) . . . . . 450 O

Part 5 – Income from active business carried on in Canada

Net income for income tax purposes from line 300 of the T2 return				1,216,728 P
Deduct: Foreign business income after deducting related expenses*	500			
Taxable capital gains **minus** allowable capital loss – amount A **minus** amount B* (page 1)**				
Net property income = amount F **minus** amount G, H, and N* (page 1)		258,232 Q		
Personal services business income after deducting related expenses*	520			
		258,232 ▶		258,232
		Net amount		958,496 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")				958,496 T

* If negative, **add** instead of **subtracting**.
**This amount may only be negative to the extent of any allowable business investment losses.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
CENTRE WELLINGTON HYDRO LTD.	86547 0769 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 [X]

	1 Class number **200**	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) **201**	3 Cost of acquisitions during the year (new property must be available for use)* **203**	4 Net adjustments** **205**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) **207**	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** **211**	7 Reduced undepreciated capital cost	8 CCA rate % **212**	9 Recapture of capital cost allowance (line 107 of Schedule 1) **213**	10 Terminal loss (line 404 of Schedule 1) **215**	11 Capital cost allowance (column 7 **multiplied** by column 8; or a lower amount) (line 403 of Schedule 1)**** **217**	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) **220**
1	1		9,765,482	3,381		0	1,691	9,767,172	4	0	0	390,687	9,378,176
2	8		923,848	22,715		38,386		908,177	20	0	0	181,635	726,542
3	10		360,455	60,580		0	30,290	390,745	30	0	0	117,224	303,811
4	10		24,508			0		24,508	30	0	0	7,352	17,156
5	17		11,975			0		11,975	8	0	0	958	11,017
6	45		17,982	19,459		0	9,730	27,711	45	0	0	12,470	24,971
7	12		3,101	52,270		0	26,135	29,236	100	0	0	29,236	26,135
8	47	Distribution Assets		299,280		0	149,640	149,640	8	0	0	11,971	287,309
9	50			6,281		0	3,141	3,140	55	0	0	1,727	4,554
		Total	11,107,351	463,966		38,386	220,627	11,312,304				753,260	10,779,671

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) plus or minus certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (06)

Canada

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		463,966		
Additions for tax purposes – Schedule 8 leasehold improvements	+			
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+			
	+			
Total additions per books	=	463,966	▶	463,966
Proceeds up to original cost – Schedule 8 regular classes		38,386		
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
	+			
Total proceeds per books	=	38,386	▶	38,386
Depreciation and amortization per accounts – Schedule 1			–	589,402
Loss on disposal of fixed assets per accounts			–	
Gain on disposal of fixed assets per accounts			+	38,386
Net change per tax return			=	-125,436

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		6,961,518
Opening net book value	–	7,086,953
Net change per financial statements	=	-125,435

If the amounts from the tax return and the financial statements differ, explain why below.

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on amalgamation or wind-up of subsidiary	Add	Deduct	Balance at the end of the year
1	Recoveries of regulatory assets	-259,998		197,602		-62,396
2	Settlement variance	414,664		699,892		1,114,556
3	Post-employment benefits	84,988			135	84,853
4						
	Reserves from Part 2 of Schedule 13					
	Totals	239,654		897,494	135	1,137,013

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
CENTRE WELLINGTON HYDRO LTD.	86547 0769 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) 100	Business Number 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	CORPORATION OF THE TOWNSHIP OF CENTRE WELLI	87256 7136 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

T2 SCH 50 (06)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
CENTRE WELLINGTON HYDRO LTD.	86547 0769 RC0001	2007-12-31

On: 2007-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part 5.

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC . . . . . ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation . . . . . ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary . . . . . ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

If the corporation's tax year includes January 1, 2006, complete "Part 5 – GRIP addition for 2006" and then line 050. Otherwise, complete line 100.

GRIP addition for 2006 (the greater of amount QQ from Part 5 or "0")	050			A
GRIP at the end of the previous tax year	100		691,044	B
Taxable income for the year (DICs enter "0")*	110	1,211,084		C
Income for the credit union deduction* (amount E in Part 3 of Schedule 17)	120			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less*	130	160,996		
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income*	140	257,808		
Subtotal (**add** lines 120, 130, and 140)		418,804 ▶	418,804	D
Income taxable at the general corporate rate (line C **minus** line D)	150	792,280		
After-tax income (line 150 **multiplied** by 68 %)			190 538,750	E
Eligible dividends received in the tax year	200	424		
Dividends deductible under section 113 received in the tax year	210			
Subtotal (**add** lines 200 and 210)		424 ▶	424	F
GRIP addition:				
Becoming a CCPC (line PP from Part 4)	220			
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230			
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240			
Subtotal (**add** lines 220, 230, and 240)		▶	290	G
Subtotal (**add** lines A or B (as applicable), E, F, and G)			1,230,218	H
Eligible dividends paid in the previous tax year	300			
Excessive eligible dividend designations made in the previous tax year	310			
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.				
Subtotal (line 300 **minus** line 310)		▶		I
GRIP before adjustment for specified future tax consequences (line H **minus** line I) (amount can be negative)			490 1,230,218	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount Y from Part 2)			560	
GRIP at the end of the year (line 490 **minus** line 560) Enter this amount on line 160 on Schedule 55.			590 1,230,218	

*** Note:** For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560 of page 1 or leave it blank.

First previous tax year 2006-12-31

Taxable income before specified future tax consequences from the current tax year		511,790 J1	
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	124,613 L1		
Aggregate investment income (line 440 of the T2 return)	M1		
Subtotal (**add** lines K1, L1, and M1)	124,613 ▶	124,613 O1	
Subtotal (line J1 **minus** line O1) (if negative, enter "0")		387,177 ▶	387,177 P1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences Q1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . R1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less S1

Aggregate investment income (line 440 of the T2 return) T1

Subtotal (**add** lines R1,S1, and T1) ▶ V1

Subtotal (line Q1 **minus** line V1) (if negative, enter "0") ▶ W1

Subtotal (line P1 **minus** line W1) (if negative, enter "0") X1

GRIP adjustment for specified future tax consequences to first previous tax year (line X1 **multiplied by** 68 %) . . . **500**

Second previous tax year 2005-12-31

Taxable income before specified future tax consequences from the current tax year 828,245 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less 149,840 L2

Aggregate investment income (line 440 of the T2 return) M2

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** N2

Subtotal (**add** lines K2, L2, M2, and N2) 149,840 ▶ 149,840 O2

Subtotal (line J2 **minus** line O2) (if negative, enter "0") 678,405 ▶ 678,405 P2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences Q2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . R2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less S2

Aggregate investment income (line 440 of the T2 return) T2

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** U2

Subtotal (**add** lines R2, S2, T2, and U2) ▶ V2

Subtotal (line Q2 **minus** line V2) (if negative, enter "0") ▶ W2

Subtotal (line P2 **minus** line W2) (if negative, enter "0") X2

GRIP adjustment for specified future tax consequences to second previous tax year (line X2 **multiplied by** 68 %) **520**

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2004-12-31

Taxable income before specified future tax consequences from the current tax year J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L3

Aggregate investment income (line 440 of the T2 return) M3

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** N3

Subtotal (**add** lines K3, L3, M3, and N3) ▶ O3

Subtotal (line J3 **minus** line O3) (if negative, enter "0") ▶ P3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences Q3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . R3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less S3

Aggregate investment income (line 440 of the T2 return) T3

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** U3

Subtotal (**add** lines R3, S3, T3, and U3) ▶ V3

Subtotal (line Q3 **minus** line V3) (if negative, enter "0") ▶ W3

Subtotal (line P3 **minus** line W3) (if negative, enter "0") X3

GRIP adjustment for specified future tax consequences to third previous tax year (line X3 **multiplied by** 68 %) . . . **540**

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . Y

Enter amount Y on line 560.

***Note**: The accelerated tax reduction was available for 2001 to 2004 tax years.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . . AA

Eligible dividends paid by the corporation in its last tax year . . . . . BB

Excessive eligible dividend designations made by the corporation in its last tax year CC

Subtotal (line BB **minus** line CC) ▶ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)
(line AA **minus** line DD) . . . . . EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . ☐ Post amalgamation . . . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . . FF

The corporation's money on hand immediately before the end of its previous/last tax year . . . . . GG

Unused and unexpired losses at the end of the corporation's previous/last tax year:

Non-capital losses . . . . .
Net capital losses . . . . .
Farm losses . . . . .
Restricted farm losses . . . . .
Limited partnership losses . . . . .

Subtotal ▶ HH

Subtotal (**add** lines FF, GG, and HH) II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . . JJ

Paid up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . . KK

All the corporation's reserves deducted in its previous/last tax year LL

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . . MM

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . . NN

Subtotal (**add** lines JJ, KK, LL, MM, and NN) ▶ OO

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0") . . . . . PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Deferral and Variance Accounts

Description of Deferral and Variance Accounts

This Schedule contains descriptions of Deferral and Variance Accounts ("DVAs") used by Centre Wellington Hydro.

COMMODITY ACCOUNTS ARE CLASSIFIED AS FOLLOWS:

1588 Retail Settlement Variance Account – Power

Description: This account is used to recover the net difference between the energy amount billed to customers and the energy charge to Centre Wellington Hydro using the settlement invoice from the Independent Electricity System Operator [IESO], host distributor and embedded generator.

1588 Retail Settlement Variance Account - Power, Sub-account Global Adjustments

Description: This account is used to recover the net difference between the provincial benefit amount billed to customers and the global adjustment charge to Centre Wellington Hydro using the settlement invoice from the Independent Electricity System Operator [IESO].

NON-COMMODITY ACCOUNTS ARE CLASSIFIED IN TWO CATEGORIES AS FOLLOWS:

Wholesale and Retail Market Variance Accounts:

1518 Retail Cost Variance Account – Retail

Description: This account is used to record the net of revenues derived from establishing retailer services agreements, distributor-consolidated billing, retailer-consolidated billing and spilt billing and the costs of entering into retailer service agreements and related contract administration, as

well as incremental costs to provide distributor-consolidated and split billing and any avoided costs credit arising from retailer-consolidated billing.

1548 Retail Cost Variance Account – STR

Description: This account is used to record the net of revenues derived from service transaction requests charged by Centre Wellington Hydro in the form of a request fee, processing fee, information request fee, default fee and other associated costs and the incremental cost of labour, internal information system maintenance costs and delivery costs related to the provision of retail transaction services.

1550 Low Voltage Variance Account

Description: This account is used to record the amounts charged to customers based on the OEB approved low voltage rate rider and Low Voltage charges billed by Hydro One Networks Inc. (H.O.N.I.) on the Power bill.

1580 Retail Settlement Variance Account - Wholesale Market Service Charges

Description: This account is used to record the net of the amount charged by the IESO based on the settlement invoice for the operation of the IESO-administered markets and the operation of the IESO-controlled grid, the amount charged by a host distributor, and the amount billed to customers using the OEB approved Wholesale Market Service Rate.

Retail Settlement Variance Account - One-time Wholesale Market Service

Description: This account is used to record the net of non-recurring amounts not included in the Wholesale Market Service Rate charged by the IESO based on the settlement invoice and the amount charged to customers for the same services using the OEB-approved rate.

1584 Retail Settlement Variance Account - Retail Transmission Network Charges

Description: This account is used to record the net of the amount charged by the IESO and / or Hydro One Networks, based on the settlement invoice, for transmission network services, the amount charged by the host distributor and the amount billed to customers using the Board Approved Transmission Network Charge.

1586 Retail Settlement Variance Account - Retail Transmission Connection Charges

Description: This account is used to record the net of the amount charged by the IESO and / or Hydro One Networks, based on the settlement invoice, for transmission connection services, the amount charged by the host distributor and the amount billed to customers using the OEB-approved Transmission Connection Charge.

Utility Deferral Accounts:

1508 Other Regulatory Assets

Description: This account includes amounts of regulatory-created assets, not included in other accounts, resulting from the ratemaking actions of the Board.

1525 Miscellaneous Deferred Debits

Description: This account includes all debits not elsewhere provided for which will benefit future periods and are carried forward and charged to expense over the term of the benefit. Specifically, Customer Information System expenses with respect to Ontario Price Credit [OPC] rebate cheques are tracked in this account.

1550 Low Voltage Variance Account

Description: Effective May 1, 2006, this account records the variances arising from low voltage transactions which are not part of the electricity market.

1555 Smart Meter Capital and Recovery Offset Variance

Description: This account records the net of the amounts paid for capitalized direct costs related to the smart meter program and the amounts charged to customers using the OEB approved smart meter rate rider.

1556 Smart Meter OM&A Variance

Description: This account records the incremental operating, maintenance, amortization and administrative expenses directly related to smart meters.

1562 Deferred Payments in Lieu of Taxes

Description: This account records the amount resulting from the OEB-approved PILs methodology for determining the 2001 deferral account allowance and the PILs proxy amount determined for 2002 and subsequent periods ending April 30, 2006.

1563 PILs contra account

Description: This account records the amounts relating to the third accounting method approved for recording entries in Account 1562 in accordance with the OEB's accounting instructions for PILs as set out in the April 2003 Frequently Asked Questions on the AP Handbook.

1565 Conservation and Demand Management Expenditures and Recoveries

Description: This account records the net of amounts incurred for conservation and demand management (CDM) activities and expenditures, the revenue proxy amount equivalent to the third tranche of market adjusted revenue requirement (MARR) and the amount charged to customers using the OEB approved CDM rate rider as well as 2006 CDM revenues and costs.

1566 CDM Contra

Description: This account records the offsetting entry for amounts recorded in account 1565, CDM Expenditures and Recoveries, pertaining to third tranche CDM programming for the reversal of entries to the accounts of original entries.

1570 Qualifying Transition Costs

Description: This account was used to record transition costs meeting the criteria established by the OEB.

1571 Pre-Market Opening Energy Variances

Description: This account was used to record the difference between the utility's purchased cost of power based on time-of-use and amounts billed to non-time-of-use customers charged at an average rate for the same period. Amounts recorded in this account started January 1, 2001 and ended on April 30, 2002.

1572 Extraordinary Event Losses

Description: This account is used to record extraordinary event costs that meet the qualifying criteria established by the OEB.

1574 Deferred Rate Impact Amounts

Description: This account is used to record amounts equal to rate impacts associated with market-based rate of return, transition costs and extraordinary costs that are determined to be excessive and decided to defer to future periods.

1590 Recovery of Regulatory Asset Balances

Description: This account records the net of amounts collected from or repaid to customers using the OEB approved regulatory asset recovery rate riders and the account balances of other regulatory assets approved on a final basis for recovery or repayment in rates when directed by the OEB. In November 2006, LDCs were advised by the OEB to reallocate the 2006 EDR approved regulatory asset balances from their account of origin to the 1590 recovery accounts effective May 1, 2006.

PILs & Tax Variance [Deferred PILs]

Description: Effective May 1, 2006 this account will be used to record the tax impact of any of the following differences:

- 1. any differences that result from a legislative or regulatory change to the tax rates or rules assumed in the 2006 OEB tax model
- 2. any differences that result from a change in, or a disclosure of, a new assessing or administrative policy that is published in the public tax administration or interpretive bulletins by relevant federal or provincial tax authorities
- 3. any differences in 2006 PILs that result in changes in a distributor's "opening" 2006 balances for tax accounts due to changes in debits and credits to those accounts arising from a tax re-assessment.

2425 Other Deferred Credits

Description: This account includes advance billings and receipts and other deferred credits not provided for elsewhere including amounts, which cannot be entirely cleared or disposed of until additional information has been received.

Calculation of Balances by Account

REQUESTED for DISPOSITION

Centre Wellington Hydro is requesting disposition of the following Deferral accounts:

1508 Other Regulatory Assets
1550 LV Variance Account
1584 RSVA – Retail Transmission Network Charges
1586 RSVA – Retail Transmission Connection Charges

Although the OEB is proposing to deal with RSVA balances through a separate process from the Cost of Service application, the Applicant feels it is necessary and in the best interest of its customers to dispose of the Transmission Connection variance as part of this process due to the materiality of the $752,822 credit in that account. Since the Transmission Network variance account is closely related to the Connection account and although the debit balance is not material, disposition of both of these accounts is requested. The applicant has also calculated revised Transmission Rates as explained in Exhibit 4 Tab 2 Schedule 12 which should result in a better match between low voltage revenues and costs. Those revised Transmission rates do not take into consideration any Hydro One proposed rate changes.

The Applicant is requesting disposition of the 2007 year-end balances in the four accounts plus interest calculated to April 30, 2009 calculated at the available OEB prescribed rates.

Table 1

Calculation of Account Balances

CALCULATION OF ACCOUNT BALANCES

	Basis for Allocation to Customer Classes	Bal @ Dec 31 07 Principal	Bal @ Dec 31 07 Interest	2008 Interest	Jan 1 - Apr 30 2009 Interest	Account Balance for Disposition
1508-Other Regulatory Assets	kwhs	$ 59,650	$ 6,207	$ 3,239	$ 1,080	$ 70,176
1550-LV Variance Account	2007 GL for A/C 1550	$ (99,515)	$ (2,760)	$ (5,404)	$ (1,801)	$ (109,481)
1584-RSVANW	Distribution Revenue	$ 13,331	$ 351	$ 724	$ 241	$ 14,647
1586-RSVACN	Distribution Revenue	$ (698,552)	$ (3,694)	$ (37,931)	$ (12,644)	$ (752,822)
Total for Disposition		$ (725,087)	$ 102	$ (39,372)	$ (13,124)	$ (777,480)

2009 Rate Rider

The methods proposed to dispose of the Deferred Variance Account balances, together with a proposed allocators is set out in this Schedule.

1508 Other Regulatory Assets

Disposal of the year end 2007 balance plus interest to April 30, 2009 over a three year period is requested.

Method of recovery: Allocation to rate classes on basis of 2009 kWh

1550 Low Voltage Charges

Disposal of the year end 2007 balance plus interest to April 30, 2009 over a three year period is requested.

Method of recovery: Allocation to rate classes on basis of 2007 customer class revenue attributable to low voltage rate which was embedded in 2007 distribution rates.

1584 Transmission Connection

Disposal of the year end 2007 balance plus interest to April 30, 2009 over a three year period is requested.

Method of recovery: Allocation to rate classes on basis of 2009 distribution revenue calculated using 2009 load projections at exiting rates.

1586 Transmission Network

Disposal of the year end 2007 balance plus interest to April 30, 2009 over a three year period is requested.

Method of recovery: Allocation to rate classes on basis of 2009 distribution revenue calculated using 2009 load projections at exiting rates.

The proposed allocators are provided in the following table:

Proposed Allocators

Table 2

Amount allocated per year	**3 year allocation**					**(259,160)**		
PROPOSED ALLOCATORS								
Allocators	Total	**Residential**	**GS < 50kW**	**GS 50 - 2,999kW**	**GS 3,000 - 4,999 kW**	**Scattered Load**	**Sentinel Lighting**	**Street Lighting**
2009 kwhs	153,831,822	45,046,630	21,809,071	64,439,774	20,979,417	400,443	43,755	1,112,732
2007 GL ratio for A/C 1550	1.0000	0.3318	0.1314	0.3870	0.1422	0.0013	0.0002	0.0061
Dist. Rev @ Exist rates	$ 2,696,957	$ 1,580,659	$ 498,881	$ 523,001	$ 80,141	$ 7,431	$ 408	$ 6,437

Proposed Method of Recovery

Proposed Deferred Variance Account Rate Riders

The proposed Rate Riders resulting from the Account Balances and Proposed Allocators are set out in the table below:

PROPOSED RATE RIDERS

Table 3

PROPOSED RATE RIDERS								
Allocation by Customer Class	Account Balance for Disposition	**Residential**	**GS < 50kW**	**GS 50 - 2,999kW**	**GS 3,000 - 4,999 kW**	**Unmetered Scattered Load**	**Sentinel Lighting**	**Street Lighting**
1508-Other Regulatory Assets	$ 70,176	$ 20,550	$ 9,949	$ 29,396	$ 9,570	$ 183	$ 20	$ 508
1550-LV Variance Account	$ (109,481)	$ (36,322)	$ (14,386)	$ (42,372)	$ (15,566)	$ (148)	$ (22)	$ (664)
1584-RSVANW	$ 14,647	$ 8,584	$ 2,709	$ 2,840	$ 435	$ 40	$ 2	$ 35
1586-RSVACN	$ (752,822)	$ (441,221)	$ (139,256)	$ (145,989)	$ (22,370)	$ (2,074)	$ (114)	$ (1,797)
Total	$ (777,480)	$ (448,410)	$ (140,984)	$ (156,124)	$ (27,931)	$ (1,999)	$ (114)	$ (1,918)
Annual Recovery Amount	$ (259,160)	$ (149,470)	$ (46,995)	$ (52,041)	$ (9,310)	$ (666)	$ (38)	$ (639)
Proposed Rate Rider		**$ (0.0033)**	**$ (0.0022)**	**$ (0.3125)**	**$ (0.2122)**	**$ (0.0017)**	**$ (0.3108)**	**$ (0.2086)**

Cost of Capital and Rate of Return

Overview of Cost of Capital and 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, and a return on equity of 9.00%, as approved by the Board in EB-2007-0814. The Applicant is requesting that the Board approve a capital structure of 56.67% debt, 43.33% equity with an equity return of 8.57%.

The Applicant is requesting this change in capital structure and associated return on equity primarily to comply with the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated August 15, 2006. That Report requires all licensed Ontario electricity distributors to move toward a 60% debt and 40% equity ratio. Details of the proposed changes are provided in Exhibit 6, Tab 1, Schedule 2. The Applicant believes the requested capital structure and the proposed cost of capital will continue to provide appropriate financing of the utility's capital and operating plans at reasonable rates.

Return on Equity:

The Applicant is requesting an equity return for the 2009 Test year of 8.57% in accordance with the cost of capital study filed at Exhibit 6, Tab 1, Schedule 4. The Applicant understands that the OEB will be finalizing the return on equity for 2009 rates based on January 2009 market interest rate information. The Applicant's use of an ROE of 8.57% is without prejudice to any revised ROE that may be adopted by the OEB in early 2009.

Cost of Debt:

Exhibit 6, Tab 1, Schedule 3 provides the details of the Applicant's forecast long-term debt cost of 7.25% for 2009. The 7.25% long-debt rate has been in place since the promissory note was

issued on the 1st of November, 2000 and no changes have been made to the note or the rate since then. The expectation of both parties to the promissory note was that the note would provide the necessary long-term financing for the utility's long-life assets as well as offering financial flexibility that would not be available from third party lenders.

The Applicant notes that its expectation of the financing being put in place to match the life of its utility assets aligns with the Board's intention that *"for ratemaking purposes the term of the debt should be assumed to be compatible with the life of the asset".* The Applicant also notes the Board's conclusion that for electricity distributors *"the asset life can extend beyond 30 years*" which clarifies the intended duration of the Board's first statement and reinforces the fixed nature of the embedded debt needed to finance its utility assets. The Applicant further notes that the Board has determined *"that for embedded debt the rate approved in prior Board decisions shall be maintained for the life of each active instrument, unless a new rate is negotiated".* These specific directions and policy conclusions from the Board's Cost of Capital Report (pp.12-13) support the continued use of the 7.25% proposed in the current proceeding.

In addition, further support is provided by the Board's rate handbook directions. For example, the promissory note was issued at 7.25% on the basis that this was an acceptable market-based rate for long-term financing since it was based on the Board assigned rates in Table 3-1 of the 2000 Distribution Rate Handbook. In particular, the Applicant relied on the Board's statement at the top of page 3-7 which confirmed that the debt rates in Table 3-1, which the Board required the distribution utilities to use, were based on the forecast long-term Canada bond rate.

The 7.25% rate was reconfirmed by the Board as an appropriate long-term debt rate in the Applicant's 2006 EDR case where the 7.25% was an integral part of the Applicant's cost of capital approved by the Board. As described in the 2006 Electricity Distribution Rate Handbook (issued May 11, 2005) at the bottom of page 32, the approved rate for debt held by an affiliate, including a municipal shareholder, "is the lower of the actual debt rate and the deemed debt rate at the time of issuance". This direction reconfirms and verifies the appropriateness of the current 7.25% rate.

Furthermore, because the Applicant's promissory note was issued within the timeframe specified in the second to last paragraph on page 32 of the 2006 Handbook, the rates shown in Table 3-1 on page 3-7 of the 2000 Handbook remain in effect, and there is no additional

requirement to demonstrate that the debt rate used was at or below market, as the Board applied this potential requirement only to applicants with debt issued before the specified timeframe. This further validates the appropriateness of using 7.25% as a market based long-term rate and, when considered in conjunction with the Board's Cost of Capital Report, as an appropriate rate for the Applicant's promissory note in this proceeding since the rate has never been changed and there is no intention on the part of the debt holder to change the rate or the nature of the note.

For all of these reasons, the Applicant has used the same rate in this application and notes that its request to the Board to continue to apply 7.25% to its embedded debt, differs significantly from the proposal made by Guelph Hydro in that: the Applicant's proposed capital structure complies with the Board's deemed structure; the Applicant's promissory note is a long-term loan due to the Township of Centre Wellington and there are no separate demand notes; the 7.25% rate has not changed since the Applicant's note was issued; there has been no repayment back to the Township, nor is one expected; and the 7.25% rate was set on the basis of the Board's directions in the 2000 and 2006 Handbooks and it has been approved by the Board.

CAPITAL STRUCTURE

Table 1

D3 Deemed Capital Structure and Return On Capital

Enter deemed portions of debt and equity capitalization

	Current Application			*2006 EDR Approved*		
	Deemed Portion	***Effective Rate [1]***	***Return Amount***	***Deemed Portion***	***Effective Rate***	***Return Amount***
Short-Term Debt	4.00%	4.47%				
Long-Term Debt	52.67%	7.25%		50.00%	7.25%	
Total Equity	43.33%	8.57%		50.00%	9.00%	
Regulated Rate of Return	**100.00%**	**7.71%**		**100.00%**	**8.13%**	
Rate Base [2]			8,818,124			8,899,155
Regulated Return on Capital			**679,945**			**723,056**
Deemed Interest Expense			*352,472*			*322,594*
Deemed Return on Equity			*327,473*			*400,462*

[1] *Long-Term Debt rate from sheet D2; Short-Term Debt and Equity rates from sheet Y1*

[2] *Amount for Current Application from sheet D1*

Cost of Debt

The following page is the Debt Balance.

D2 2009 Debt Balances

Enter details of debt balances outstanding in 2009 (excluding short-term debt e.g. line of credit)

Description	Amount	Issue Date (dd-mmm-yyyy)	Term Date (dd-mmm-yyyy)	Interest Rate (a)	Other Costs (b)	Due to Affiliate?	Annual Cost (c)
Promissory Note	5,046,753	1-Nov-2000	Open	7.25%		YES	365,890

Description	Effective Rate	Days o/s in 2009	Average Balance	2009 Cost	2009 Ending Balance	Debt o/s USA #	Int. Expense USA #
Promissory Note	7.25%	365	5,046,753	365,890	5,046,753	2520	6005
TOTAL	**7.25%**		**5,046,753**	**365,890**	**5,046,753**		

(a) For debt held issued prior to 31-Mar-2006 (prior Test Year approval, per sheet A1), represents the previously approved rate.

(b) Annual charges other than interest (e.g. commitment fees, amortization of issuance costs, etc.)

(c) For debt issued to an affiliate since 31-Mar-2006, represents the lower of (i) actual cost and (ii) cost based on the deemed debt rate (5.25%, per sheet Y1)

Return on Equity

The calculations used to determine the ROE and the debt are taken from the OEB's "Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors" issued August 15, 2006.

The following are extracts from Appendix A and B to 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 EDR, 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 (*LCBFt*) 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 (*LTDRt*) 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];
- ***30CBw,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 *LCBFt* 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:

1. **10CB3,T** is the 3-month forecast of the 10-year Government of Canada bond yield as published in *Consensus Forecasts* at time *t*;
2. **10CB12,t** is the 12-month forecast of the 10-year Government of Canada bond yield as published in *Consensus Forecasts* at time *t*;
3. **30CBi,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*;
4. **10CBi,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
5. $\boldsymbol{I_t}$ 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*.

Calculation of Revenue Deficiency or Surplus

Overview of Utility Revenue

This exhibit presents an overview of the revenue deficiency or surplus calculations used to project the deficiency of revenue for the 2009 Test year. The steps used in this process are:

- Calculate the Service Revenue using the Rate Base (Exhibit 2), OM & A and Amortization Expenses calculated in Exhibit 4 and the Return on Capital calculated in Exhibit 6.

- Calculate the Base Revenue requirement using the PILs calculation and the Revenue Offsets from Exhibit 3.

- Use the existing rates and load projections to calculate

- Utility Income - Net of Taxes and PILs

- Use those Calculated Revenues and the Base Revenue requirement to determine Revenue Deficiency or Sufficiency.

The Applicant projects that it will need to recover $3,075,196 in service revenue in the 2009 Test Year through distribution rates and other regulated charges. This includes:

- $ 2,739,753 recovered through fixed and variable distribution rates including Transformer Allowance of $84,849 and LV charges of $91,000;
- $ 335,443 recovered through Administration, Specific Service Charges and Other Miscellaneous Revenue.

At the existing distribution rates, the Applicant's 2009 Test Year gross revenue deficiency is calculated as $216,645. It is derived from the chart in Exhibit 7, Tab 1, Schedule 2.

Determination of Revenue Deficiency or Surplus

	2009 Projection	2008 Projection		Var #	Var %
Utility Income	470,927	537,453		(66,526)	(12.4%)
Utility Rate Base	8,818,124	8,842,442		(24,318)	(0.3%)
Indicated Rate of Return	5.34%	6.08%		(0.74%)	(12.1%)
Requested / Approved Rate of Return	7.71%	7.71%			
Sufficiency / (Deficiency) in Return	(2.37%)	(1.63%)		(0.74%)	(45.2%)
Net Revenue Sufficiency / (Deficiency)	**(209,018)**	**(144,367)**		**(64,651)**	**(44.8%)**
Provision for PILs/Taxes	(7,627)	(7,647)		21	0.3%
Gross Revenue Sufficiency / (Deficiency)	**(216,645)**	**(152,014)**		**(64,631)**	**(42.5%)**
Deemed Overall Debt Rate	*7.05%*	*7.25%*		*(0.20%)*	*(2.7%)*
Deemed Cost of Debt	*352,472*	*320,539*		*31,934*	*10.0%*
Utility Income less Deemed Cost of Debt	*118,455*	*216,915*		*(98,460)*	*(45.4%)*
Return On Deemed Equity	*3.10%*	*5.66%*		*(2.56%)*	*(45.2%)*
UTILITY INCOME					
Total Net Revenues	2,858,551	2,891,576		(33,024)	(1.1%)
OM&A Expenses	1,711,600	1,699,900		11,700	0.7%
Depreciation & Amortization	638,185	594,185		43,999	7.4%
Taxes other than PILs / Income Taxes	35,000	33,000		2,000	6.1%
Total Costs & Expenses	2,384,785	2,327,085		57,699	2.5%
Utility Income before Income Taxes / PILs	473,767	564,490		(90,724)	(16.1%)
PILs / Income Taxes	2,839	27,037		(24,198)	(89.5%)
Utility Income	**470,927**	**537,453**		**(66,526)**	**(12.4%)**

The forecasted revenue deficiency is mainly attributable to the fact that the 2006 EDR rates are based on 2003/4 costs and therefore do not reflect the actual and forecasted increases in OM & A costs and Capital Investments.

The 2006 EDR was based on historic (average of 2003 & 2004) net fixed assets balances, and the 2004 additions were subject to the half year rule.

The Applicant has made significant capital investments through the period 2004 – 2007 and will continue to invest in Capital projects in 2008 and 2009.

This increase in investments, results in an increase in return on capital, depreciation expense and in working capital.

The recovery of Regulatory Assets is not included in the revenue requirement. Regulatory Assets are recovered through a separate rate rider. Regulatory Assets, deferral accounts and recoveries are explained in Exhibit 5.

Cost Allocation

Proposed Method (if different from Board Approved Method)

On September 29, 2006, the OEB issued its directions on Cost Allocation Methodology for Electricity Distributors (the "Directions"). On November 15, 2006, the Board issued the Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model (the "Model") and User Instructions (the "Instructions") for the Model. The Applicant prepared a cost allocation information filing consistent with the Applicant's understanding of the Directions, the Guidelines, the Model and the Instructions. The Applicant submitted this filing to the OEB on March 29, 2007.

One of the main objectives of the filing was to provide information on any apparent cross-subsidization among a distributor's rate classifications.

Summary of Results and Proposed Changes

Results of the Cost Allocation Study:

The data used in the Cost Allocation Model was consistent with the Applicant's cost data that supported its 2006 OEB-approved distribution rates. Consistent with the Guidelines, the Applicant's assets were broken out into primary and secondary distribution functions. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to all Utilities, its engineering records, and its customer and financial information systems.

The results of a cost allocation study are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

The following table outlines the revenue to cost ratios from the Cost Allocation Informational Filing submitted by the Applicant. In addition, the dollar amount by which each rate classification is being subsidized or over-contributing is provided. The calculations are based on the Applicant's OEB-approved 2006 electricity distribution rates.

Table 1

Revenue to Cost Ratios as Filed in Centre Wellington Hydro

Cost Allocation Informational Filing

Rate Classification	Revenue to Cost Ratio	$(Being Subsidized)/ $Over-Contributing
Residential	106.51%	$99,365
GS <50 kW	109.71%	$43,608
GS>50 – 2,999 kW	114.91%	$67,706
GS>3,000 – 4,999 kW	65.07%	($34,116)
Unmetered Scattered Load	138.26%	$3,941
Sentinel Lighting	16.01%	$(3,608)
Street Lighting	8.72%	$(176,897)
Total		0

Proposed Adjustment to Cost Allocation:

On November 28, 2007, the OEB issued its "Report on Application of Cost Allocation for Electricity Distributors" (the "Cost Allocation Report"). In the Cost Allocation Report, the OEB established what it considered to be the appropriate ranges of revenue to cost ratios which are summarized in Table 2 below. As can be seen from the table, the Applicant's Cost Allocation Filing Results, only the Residential, GS<50kW and GS >50-2999kW customer classes currently fall within the revenue to cost ratio ranges established by the OEB. The table also provides the Proposed 2009 Revenue to Cost ratios for comparison purposes. The calculations providing the proposed ratios will be discussed later in this Exhibit.

Table 2

OEB Proposed Revenue to Cost Ratio Ranges & Centre Wellington Hydro Results

Customer Class	OEB Low	OEB High	Centre Wellington Hydro Cost Allocation Filing Results	Centre Wellington Hydro Proposed 2009 Revenue to Cost Ratios
Residential	85%	115%	106.51%	103.00%
GS <50 kW	80%	120%	109.71%	106.62%
GS>50 – 2,999 kW	80%	180%	114.91%	112.82%
GS>3,000 – 4,999 kW	80%	180%	65.07%	87.30%
Unmetered Scattered Load	80%	120%	138.26%	112.08%
Sentinel Lighting	70%	120%	16.01%	45.23%
Street Lighting	70%	120%	8.72%	40.47%

As can be seen in Table 3 below, the Applicant is proposing to re-align its revenue to cost ratios in this application by adjusting the allocations of its Base Revenue Requirement, before Transformer Allowance and Low Voltage, among its rate classes in order to reduce the cross-subsidization. Transformer Allowance and Low voltage is then added to the resulting class revenues to arrive at the Gross Base Revenue Requirement.

Table 3

Allocation of Base Revenue Requirement

		Outstanding Base Revenue Requirement %			Outstanding Base Revenue Requirement $ [3]		Directly	Total Base
Customer Class Name	**Cost Allocation [1]**	**Existing Rates [2]**	**Rate Application**	**Cost Allocation**	**Existing Rates**	**Rate Application**	**Assigned Revenues [3]**	**Revenue Requirement**
Residential	54.74%	58.61%	56.38%	1,499,702	1,605,741	1,544,673		1,544,673
General Service Less Than 50 kW	16.42%	18.50%	17.51%	449,838	506,797	479,621		479,621
General Service 50 to 2,999 kW	17.19%	19.39%	19.39%	470,885	531,300	531,238		531,238
General Service 3,000 to 4,999 kW	3.72%	2.97%	3.25%	101,993	81,413	89,042		89,042
Unmetered Scattered Load	0.36%	0.28%	0.40%	9,778	7,549	10,959		10,959
Sentinel Lighting	0.16%	0.02%	0.07%	4,482	414	2,027		2,027
Street Lighting	7.41%	0.24%	3.00%	203,074	6,539	82,193		82,193
TOTAL	**100.00%**	**100.00%**	**100.00%**	**2,739,753**	**2,739,753**	**2,739,753**		**2,739,753**

	Total Base	Transformer	Low Voltage	Gross Base
Customer Class Name	**Revenue Requirement**	**Allowance Recovery [4]**	**Revenue Required [5]**	**Revenue Requirement**
Residential	1,544,673		29,326	1,573,999
General Service Less Than 50 kW	479,621		12,595	492,216
General Service 50 to 2,999 kW	531,238	58,940	36,851	627,029
General Service 3,000 to 4,999 kW	89,042	25,908	11,451	126,401
Unmetered Scattered Load	10,959		231	11,190
Sentinel Lighting	2,027		21	2,049
Street Lighting	82,193		525	82,717
TOTAL	**2,739,753**	**84,849**	**91,000**	**2,915,601**

Footnotes:

1: from sheet F3-Cost Allocation

2: from sheet C4-Dist Revenue

3: from sheet F2-Direct Revenues

4. Volume per sheet C4-Dist Revenue-total transformer allowance must match total amount of the allowance

5: from sheet F4-Revenue Allocation

The Applicant is proposing to move in the direction of a revenue to cost ratio of 100% in this rate application for all customer classes. However, since the revenue to cost ratios for Street Lighting, and Sentinel Lighting were so low in the Cost Allocation Filing, the Applicant is proposing to move both of those classes approximately half way to the lower side of the revenue to cost band in this application and proposes to move towards revenue to cost ratios of 70% during the 2 year IRM period 2010 and 2011. The intent of this proposal is to reduce the rate impact for the customers within those two customer classes.

Table 4 provides a comparison of the 2009 Allocated Revenue versus the 2009 Allocated Cost to arrive at the proposed Revenue to cost ratios. The Allocated Cost is calculated by multiplying the Base Revenue Requirement times the revenue proportions from the cost allocation filing.

As noted earlier the revenue to cost ratio for all customer classes are moving in the direction of a revenue to cost ratio of 100%.

Table 4

Revenue to Cost Ratios

	Rate Application			Cost Allocation		Target Range	
Customer Class Name	**Allocated Revenue [8]**	**Allocated Cost [8]**	**Revenue to Cost Ratio**	**Revenue to Cost Ratio [9]**	**Variance**	**Floor**	**Ceiling**
Residential	$1,544,673	$1,499,702	1.03	1.07	-0.04	0.85	1.15
General Service Less Than 50 kW	$ 479,621	$ 449,838	1.07	1.10	-0.03	0.8	1.2
General Service 50 to 2,999 kW	$ 531,238	$ 470,885	1.13	1.15	-0.02	0.8	1.8
General Service 3,000 to 4,999 kW	$ 89,042	$ 101,993	0.87	0.65	0.22	0.8	1.8
Unmetered Scattered Load	$ 10,959	$ 9,778	1.12	1.38	-0.26	0.8	1.2
Sentinel Lighting	$ 2,027	$ 4,482	0.45	0.16	0.29	0.7	1.2
Street Lighting	$ 82,193	$ 203,074	0.40	0.09	0.32	0.7	1.2
TOTAL	$2,739,753	$2,739,753	1	0	1		

Footnotes:

8: see table 3 (Outstanding Revenue Requirement $)

9: see Sheet F3-Cost Allocation

Cost Allocation Summary:

The discussion and tables above support the Applicant's proposed reallocation of distribution revenues across customer classes, in order to begin moving toward revenue to cost ratios of 100% and reduce cross-subsidization. The Applicant submits that the proposed reallocation of distribution revenue is fair and reasonable for the following reasons:

- Customer class revenues will more closely reflect the actual costs of providing distribution service to that class;
- Partial reallocation provides time for further refinement of the cost allocation model and movement between classes;
- The further reallocation to the Street and Sentinel Lighting customer classes continue in 2010 and 2011 with proposed offsets to those classes who are still above the revenue to cost ration of 1.0.
- The associated rate impacts are manageable and do not create rate shock for any customer class as shown in the rate design section.

Rate Design

Rate Design Overview

This exhibit documents the calculation of the Applicant's proposed distribution rates by rate class for the 2009 test year, based on the rate design proposed in this Exhibit.

The Applicant has determined its total 2009 service revenue requirement to be $3,075,196. The total revenue offsets in the amount of $335,443 reduce the Applicant's total service revenue requirement to a base revenue requirement of $2,739,753 excluding transformer allowance and LV charges. The base revenue requirement is derived from the Applicant's 2009 capital and operating forecasts, weather normalized usage, forecasted customer counts, and the Applicant's regulated return on rate base. The revenue requirement is summarized in the table below:

Calculation of Base Revenue Requirement

Table 1

		2009 Projection	Non-recurring items (Total)	2009 Normalized
OM&A Expenses	*from sheet D1*	1,746,600		1,746,600
3850-Amortization Expense	*from sheet E2*	638,185		638,185
Total Distribution Expenses		2,384,785		2,384,785
Regulated Return On Capital	*from sheet D3*	679,945		679,945
PILs (with gross-up)	*from sheet E4*	10,466		10,466
Service Revenue Requirement		**3,075,196**		**3,075,196**
Less: Revenue Offsets	*from sheet C9*	335,443		335,443
Base Revenue Requirement		**2,739,753**		**2,739,753**

The outstanding Base Revenue Requirement is allocated to the various rate classes using the following proposed apportionment of revenue as outlined in Exhibit 8 – Cost Allocation and repeated below on Table 2.

Proposed Apportionment of Revenue to Rate Classes

Table 2

Rate Classification	Proposed Proportion of Revenue
Residential	56.38%
GS<50 kW	17.51%
GS>50 – 2,999 kW	19.39%
GS>3,000 – 4,999 kW	3.25%
Unmetered Scattered Loads	0.40%
Sentinel Lights	0.07%
Street Lights	3.00%
Total	100.00%

The following table outlines the results of this allocation which is then adjusted for Transformer allowance Recovery and Low Voltage Revenue required to arrive at Gross Base Revenue Requirement.

Allocation of Outstanding Base Revenue Requirement
Plus Transformer Allowance and Low Voltage
Table 3

Customer Class Name	Total Base Revenue Requirement	Transformer Allowance Recovery [4]	Low Voltage Revenue Required [5]	Gross Base Revenue Requirement
Residential	1,544,673		29,326	1,573,999
General Service Less Than 50 kW	479,621		12,595	492,216
General Service 50 to 2,999 kW	531,238	58,940	36,851	627,029
General Service 3,000 to 4,999 kW	89,042	25,908	11,451	126,401
Unmetered Scattered Load	10,959		231	11,190
Sentinel Lighting	2,027		21	2,049
Street Lighting	82,193		525	82,717
TOTAL	**2,739,753**	**84,849**	**91,000**	**2,915,601**

Determination of Monthly Fixed Charges:

The Applicant's current OEB-approved monthly fixed charges based on its 2008 IRM application by customer class are included in Table 4 below.

Using the existing approved fixed charges applied to the forecasted number of customers for 2009, the following table outlines the current split between fixed and variable distribution revenue.

Existing Fixed Variable Split using Existing Monthly Service Charge

Table 4

Customer Class Name	Existing Rates (1)		
	Rate	Fixed %	Variable %
Residential	$13.01	56.40%	43.60%
General Service Less Than 50 kW	$13.69	22.62%	77.38%
General Service 50 to 2,999 kW	$41.96	5.10%	94.90%
General Service 3,000 to 4,999 kW	$558.01	8.36%	91.64%
Unmetered Scattered Load	$14.29	4.62%	95.38%
Sentinel Lighting	$0.46	47.40%	52.60%
Street Lighting	$0.16	49.45%	50.55%

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, interveners 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 follow-up to the review of the cost allocation filings, the OEB issued a "Board Staff Discussion Paper on the Implications Arising from a Review of the Electricity Distributors' Cost Allocation Filings" (EB-2008-0667), in which OEB staff requested comments on proposed ranges for revenue to cost ratios and well as ranges for the fixed distribution charges.

Board staff made the suggestion in Section 3.5 of the Discussion Paper (Implications Arising from the Determination of class Specific Revenue to Cost Ratios) that "no distributor's revenue to cost ratios should be outside the ranges, without significant justification…" and further that "Any distributor with a class ratio that falls outside the suggested ranges should re-align its distribution rates so that all classes fall with the respective ranges." OEB staff further recognize throughout this section that "for some customer classes, there could be higher than average rate adjustments." and that "Any significant adjustments to rates must consider the range of factors associated with rate changes which may not allow for immediate full adjustments."

In Section 4 of the Discussion Paper, OEB staff provided an analysis of fixed distribution charges and suggested an upper and lower range based on the minimum system concept. This concept has been a long-standing methodology for cost allocation studies, however OEB staff proposed that each distributor set fixed rates within these ranges "at the time of its next rebasing rate application."

In its November 28, 2008 Report on Application of Cost Allocation for Electricity Distributors, referred to in Exhibit 8 above, the OEB addressed a number of "Other Rate Matters", including the treatment of the fixed rate component (the Monthly Service Charge, or "MSC") of the bill. At page 12 of the Report, the OEB determined that the floor amount for the MSC should be the avoided costs, as that term is defined in the September 29, 2006 report of the OEB entitled "Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors".

With respect to the upper bound for the MSC, the OEB considered it to be inappropriate to make changes to the MSC ceiling at this time, given the number of issues that remain to be examined within the scope of the OEB's Rate Review proceeding (EB-2008-0031). The OEB indicated that for the time being, it does not expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the MSC; and that distributors that are currently above that value are not required to make changes to their current MSC to bring it to or below that level at this time.

The Applicant is proposing in this application to change the Monthly Service Charges, while keeping within the boards November 28, 2007 guidelines, which results in a change to the fixed variable proportions. The following Table provides the Applicant's calculations of its proposed monthly fixed distribution charges for the 2009 Test Year and the resulting Fixed Variable splits.

Proposed Monthly Service Charges and Fixed Variable Splits

Table 5

		Existing Fixed/Variable Split (3)		Rate Application		
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**
Residential	$12.96	56%	44%	$14.00	61%	39%
General Service Less Than 50 kW	$13.51	23%	77%	$15.44	26%	74%
General Service 50 to 2,999 kW	$50.31	5%	95%	$130.45	13%	87%
General Service 3,000 to 4,999 kW	$880.11	8%	92%	$558.28	5%	95%
Unmetered Scattered Load	$21.52	5%	95%	$16.65	4%	96%
Sentinel Lighting	$2.31	47%	53%	$2.72	56%	44%
Street Lighting	$2.06	49%	51%	$2.36	57%	43%

Proposed Volumetric Charges:

The variable distribution charge is calculated by dividing the variable distribution portion of the Gross Base Revenue Requirement by the appropriate 2009 Test Year usage, kWh or kW, as the class charge determinant.

The following Table 6 provides the Applicant's calculations of its proposed variable distribution charges for the 2009 Test Year assuming the same fixed/variable split used in designing the current approved rates.

Variable Distribution Charge Calculation

Table 6

Customer Class Name	Total Base Revenue Requirements	Variable Revenue Proportion	2009 Test Volumetric Billing Determinant	Proposed Volumetric Distribution Charge
Residential	$ 1,544,673	39.05%	45,046,630	0.0134
General Service Less Than 50 kW	$ 479,621	74.14%	21,809,071	0.0163
General Service 50 to 2,999 kW	$ 531,238	86.77%	166,526	2.7680
General Service 3,000 to 4,999 kW	$ 89,042	94.70%	43,874	1.9219
Unmetered Scattered Load	$ 10,959	96.43%	400,443	0.0264
Sentinel Lighting	$ 2,027	44.24%	122	7.3516
Street Lighting	$ 82,193	43.23%	3,066	11.5903
Total	$ 2,739,753			

Proposed Distribution Rates:

The following table sets out the Applicant's proposed 2009 electricity distribution rates based on the foregoing calculations. Although the Applicant has not included any forecast for Smart Meters, as a result of not currently being included in the Ministry regulations, for the Applicant is requesting Board approval for the continuation of the $ 0.27 per metered customer per month. The final proposed rates therefore include the Base Revenue Requirement, adjusted for Transformer Allowance Recovery, LV Revenue Required, and the Smart Meter rate adder.

Proposed 2009 Electricity Distribution Rates

Table 7

Customer Class Name	*per Sheet F6*	Smart Meters	TOTAL	* Default Loss Factor
Residential	$14.00	$0.27	$14.27	1.0681
General Service Less Than 50 kW	$15.44	$0.27	$15.71	1.0681
General Service 50 to 2,999 kW	$130.45	$0.27	$130.72	1.0681
General Service 3,000 to 4,999 kW	$558.28	$0.27	$558.55	1.0681
Unmetered Scattered Load	$16.65		$16.65	1.0681
Sentinel Lighting	$2.72		$2.72	1.0681
Street Lighting	$2.36		$2.36	1.0681

Customer Class Name	Rate
Residential	$0.0136
General Service Less Than 50 kW	$0.0167
General Service 50 to 2,999 kW	$3.2671
General Service 3,000 to 4,999 kW	$2.7283
Unmetered Scattered Load	$0.0269
Sentinel Lighting	$7.4289
Street Lighting	$11.6642

Line Loss Category (per sheet C3)	Loss Factor	Allowances	Rate
Secondary Metered Customer <5000 kW	1.0681	Transformer Ownership ($/kW) *	($0.6000)
Primary Metered Customer <5000 kW	1.0574	Primary Metering Allowance (%)	(1.00%)
		* per sheet F4	

Rate Mitigation

The Applicant submits that the bill impacts of its proposed 2009 electricity distribution rates are reasonable and with the exception of Street Light and Sentinel Light Classes, no mitigation is necessary.

As mentioned previously in Exhibit 8 - Cost Allocation, the Applicant is proposing to move to the revenue to cost ratios for Street Lighting and Sentinel Lighting classes from the existing Cost Allocation R/C ratio by one-half of the difference between the existing ratio and the R/C ratio of 70% in an effort to mitigate the increase to those customers. The Applicant proposes the R/C ratios move to 70% over the 2 years of the 3rd Generation IRM process following this cost of service rate application.

Existing Rate Classes

Residential:

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are served by single-phase lines.

General Service Less Than 50kW:

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

General Service 50 – 2,999 kW:

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 3,000 kW. Note that for the application of the Retail Transmission Rate – Network Service Rate and the Retail Transmission Rate – line and Transformation Connection Service Rate the following sub-classifications apply:

General Service 50 to 1,000 kW non-interval metered

General Service 50 to 1,000 kW interval metered

General Service greater than 1,000 to 3,000 kW interval metered

General Service 3,000 – 4,999 kW:

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than 3,000 kW but less than 5,000 kW.

Unmetered Scattered Load:

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

Sentinel Lighting:

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light.

Street Lighting:

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times and the required lighting times established in the load shape template approved for street lighting by the OEB.

Existing Rate Schedule

The following pages are the latest rates per OEB order.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2007-0814

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 Centre Wellington Hydro Ltd. pursuant to section 78 of the Ontario Energy Board Act seeking approval to amend electricity distribution rates.

BEFORE: Paul Vlahos
Presiding Member

Paul Sommerville
Member

RATE ORDER

Centre Wellington Hydro Ltd. ("Centre Wellington") is a licensed distributor of electricity providing service to consumers within its licensed service area. Centre Wellington 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.

On March 14, 2008, the Board issued its Decision (the "Decision") regarding Centre Wellington's application.

The Board directed that Centre Wellington file with the Board a proposed Tariff of Rates and Charges reflecting the Board's Decision, within 7 days of the date of the Decision.

Centre Wellington has provided the Board with a proposed Tariff of Rates and Charges.

The Board is satisfied that the document accurately reflects the Decision.

For completeness of the regulated charges, the Board has included in the Tariff of Rates and Charges the charges pertaining to services provided to retailers or consumers regarding the supply of competitive electricity, which are referenced in Chapter 12 of the 2006 Electricity Distribution Rate Handbook.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix "A" of this Rate Order is approved, effective May 1, 2008, for electricity consumed or estimated to have been consumed on and after May 1, 2008.

2. The Tariff of Rates and Charges set out in Appendix "A" of this Order supersedes all previous distribution rate schedules approved by the Board for Centre Wellington and is final in all respects.

3. Centre Wellington shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, April 21, 2008
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix "A"
To The Rate Order Arising from Decision
EB-2007-0814
Centre Wellington Hydro Ltd.

April 21, 2008

Centre Wellington Hydro Ltd.
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-2007-0814

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, 2008 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2008 for all charges incurred by customers on or after that date.
RETAIL SERVICE CHARGES – May 1, 2008 for all charges incurred by retailers or customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2008 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 is for single dwelling units with separate metering, detached, semi-detached, triplex, etc.

General Service Less Than 50 kW
This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

General Service 50 to 2,999 kW
This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 3,000 kW. Note that for the application of the Retail Transmission Rate – Network Service Rate and the Retail Transmission Rate – Line and Transformation Connection Service Rate the following sub-classifications apply:
- General Service 50 to 1,000 kW non-interval metered
- General Service 50 to 1,000 kW interval metered
- General Service greater than 1,000 to 3, 000 kW interval metered.

General Service 3,000 to 4,999 kW
This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 3,000 kW but less than 5,000 kW.

Unmetered Scattered Load
This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

Sentinel Lighting
This classification refers to an account that is an unmetered lighting load supplied to a sentinel light where consumption is based on connected load.

Street Lighting
This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

Centre Wellington Hydro Ltd.
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-2007-0814

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	13.28
Distribution Volumetric Rate	$/kWh	0.0153
Retail Transmission Rate – Network Service Rate	$/kWh	0.0039
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0062
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	$	13.96
Distribution Volumetric Rate	$/kWh	0.0177
Retail Transmission Rate – Network Service Rate	$/kWh	0.0035
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0055
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 2,999 kW

Service Charge	$	42.23
Distribution Volumetric Rate	$/kW	2.9804
Retail Transmission Rate – Network Service Rate	$/kW	1.4327
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.2069
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	1.5153
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.4210
Retail Transmission Rate – Network Service Rate – Interval Metered >1,000kW	$/kW	1.5135
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered >1,000kW	$/kW	2.4407
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 3,000 to 4,999 kW

Service Charge	$	558.28
Distribution Volumetric Rate	$/kW	1.6740
Retail Transmission Rate – Network Service Rate	$/kW	1.6024
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.6029
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)	$	14.29
Distribution Volumetric Rate	$/kWh	0.0177
Retail Transmission Rate – Network Service Rate	$/kWh	0.0035
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0055
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Centre Wellington Hydro Ltd.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008

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EB-2007-0814

Sentinel Lighting

Service Charge (per connection)	$	0.46
Distribution Volumetric Rate	$/kW	1.7575
Retail Transmission Rate – Network Service Rate	$/kW	1.0860
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7418
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)	$	0.16
Distribution Volumetric Rate	$/kW	1.0613
Retail Transmission Rate – Network Service Rate	$/kW	1.0805
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7061
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
Request for Other Billing Information	$	15.00
Easement Letter	$	15.00
Notification Charge	$	15.00
Account History	$	15.00
Returned Cheque (Plus Bank Charges)	$	15.00
Charge to Certify Cheque	$	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 Disconnection	$	30.00
Collection of Account Charge – No Disconnection – After Regular Hours	$	165.00
Disconnect/Reconnect Charge – At Meter – During Regular Hours	$	65.00
Disconnect/Reconnect Charge – At Meter – After Hours	$	185.00
Disconnect/Reconnect Charge – At Pole – During Regular Hours	$	185.00
Disconnect/Reconnect Charge – At Pole – After 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 & Remove – Overhead – No Transformer	$	500.00
Temporary Service Install & Remove – Underground – No Transformer	$	300.00
Temporary Service Install & Remove – Overhead – With Transformer	$	1000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Centre Wellington Hydro Ltd.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008

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EB-2007-0814

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	1.0472
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0367
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Proposed Rate Classes (if different than existing)

The Applicant is not requesting any changes to the existing rate classes.

1 Proposed Rate Schedule

Residential

Service Charge	$	14.27
Distribution Volumetric Rate	$/kWh	0.0136
Regulatory Asset Recovery	$/kWh	(0.0033)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0046
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	15.71
Distribution Volumetric Rate	$/kWh	0.0167
Regulatory Asset Recovery	$/kWh	(0.0022)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0050
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 2,999 kW

Service Charge	$	130.72
Distribution Volumetric Rate	$/kW	3.2671
Regulatory Asset Recovery	$/kW	(0.3125)
Retail Transmission Rate – Network Service Rate	$/kW	2.0328
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6548
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 3,000 to 4,999 kW

Service Charge	$	558.55
Distribution Volumetric Rate	$/kW	2.7283
Regulatory Asset Recovery	$/kW	(0.2122)
Retail Transmission Rate – Network Service Rate	$/kW	2.2736
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9518
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	$	16.65
Distribution Volumetric Rate	$/kWh	0.0269
Regulatory Asset Recovery	$/kWh	(0.0017)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0050
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	2.72
Distribution Volumetric Rate	$/kW	7.4289
Regulatory Asset Recovery	$/kW	(0.3108)
Retail Transmission Rate – Network Service Rate	$/kW	1.5409
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3061
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)	$	2.36
Distribution Volumetric Rate	$/kW	11.6642
Regulatory Asset Recovery	$/kW	(0.2086)
Retail Transmission Rate – Network Service Rate	$/kW	1.5331
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2793
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

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
Retailer Service Agreement -- standard charge	$	100.00
Retailer Service Agreement -- monthly fixed charge (per retailer)	$	20.00
Retailer Service Agreement -- monthly variable charge (per customer)	$	0.50
Distributor-Consolidated Billing -- monthly charge (per customer)	$	0.30
Retailer-Consolidated Billing -- monthly credit (per customer)	$	(0.30)
Service Transaction Request -- request fee (per request)	$	0.25
Service Transaction Request -- processing fee (per processed request)	$	0.50

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 <5000 kW	1.0681
Primary Metered Customer <5000 kW	1.0574

1

2

Rate Impacts

This Schedule presents the results of the assessment of customer total bill impacts by level of consumption by customer per rate class and per the total customer class.

Impacts are derived using the applicable May 1, 2008 rates and the proposed 2009 distribution rates (including Rate Rider for the recovery of Deferral and Variance Accounts), proposed 2009 Retail Transmission Service Rates, and the Applicant's proposed Loss Factor.

The total bill impacts are calculated for each rate class at various levels of consumption. The rate impacts are assessed on the basis of moving to the proposed distribution rates.

Summary of Bill Impacts

The following tables provide a summary of the rate impacts for each of the classes based on the proposed 2009 rates and the various volumes. The proposed rate increases are manageable for all classes. However, as stated above and in Exhibit 8 – Cost Allocation, the increases to bring Street Lighting and Sentinel Lighting within the revenue to cost ratio are being mitigated over a three year period.

Residential - Bill Impact Summary

Table 7

Volume		RPP	Distribution Charges		Total Bill	
kWh *	kW	Rate Class	$ change	% change	$ change	% change
500		Summer	$0.14	0.7%	($0.77)	(1.3%)
1,000		Summer	($0.71)	(2.5%)	($2.34)	(2.1%)
1,500		Summer	($1.56)	(4.3%)	($4.02)	(2.5%)
500		Winter	$0.14	0.7%	($0.77)	(1.3%)
1,000		Winter	($0.71)	(2.5%)	($2.34)	(2.2%)
1,500		Winter	($1.56)	(4.3%)	($4.02)	(2.6%)

Residential Bill Impact – 1000 kWh

Table 8

Residential **RPP: Summer**

1,000 kWh's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$13.28			$14.27	$0.99	7.5%
Distribution	kWh	1,000	$0.0153	$15.30	1,000	$0.0136	$13.60	($1.70)	(11.1%)
Sub-Total (Distribution)				**$28.58**			**$27.87**	**($0.71)**	**(2.5%)**
Deferral/Variance	kWh	1,000			1,000	($0.0033)	($3.30)	($3.30)	
Electricity (Commodity)	kWh	1,047	RPP-Summer	$56.38	1,068	RPP-Summer	$57.62	$1.24	2.2%
Transmission - Network	kWh	1,047	$0.0039	$4.08	1,068	$0.0055	$5.91	$1.83	44.9%
Transmission - Connection	kWh	1,047	$0.0062	$6.49	1,068	$0.0046	$4.97	($1.52)	(23.4%)
Wholesale Market Service	kWh	1,047	$0.0052	$5.45	1,068	$0.0052	$5.55	$0.10	1.8%
Rural Rate Protection	kWh	1,047	$0.0010	$1.05	1,068	$0.0010	$1.07	$0.02	1.9%
Debt Retirement Charge	kWh	1,000	$0.0070	$7.00	1,000	$0.0070	$7.00		
TOTAL BILL				**$109.03**			**$106.69**	**($2.34)**	**(2.1%)**

General Service (less 50kW) – Bill Impact Summary

Table 9

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
2,000		Non-res.	($0.25)	(0.5%)	($1.34)	(0.6%)
3,000		Non-res.	($1.25)	(1.9%)	($2.93)	(0.9%)
5,000		Non-res.	($3.25)	(3.2%)	($6.03)	(1.2%)
10,000		Non-res.	($8.25)	(4.3%)	($13.78)	(1.3%)
17,500		Non-res.	($15.75)	(4.9%)	($25.44)	(1.4%)

General Service (less 50 kW) – 3000 kWh

Table 10

General Service Less Than 50 kW **RPP: Non-res.**

3,000 kWh's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$13.96			$15.71	$1.75	12.5%
Distribution	kWh	3,000	$0.0177	$53.10	3,000	$0.0167	$50.10	($3.00)	(5.6%)
Sub-Total (Distribution)				**$67.06**			**$65.81**	**($1.25)**	**(1.9%)**
Deferral/Variance	kWh	3,000			3,000	($0.0022)	($6.60)	($6.60)	
Electricity (Commodity)	kWh	3,142	RPP-Non-res.	$178.60	3,204	RPP-Non-res.	$182.30	$3.70	2.1%
Transmission - Network	kWh	3,142	$0.0035	$11.00	3,204	$0.0050	$15.91	$4.91	44.6%
Transmission - Connection	kWh	3,142	$0.0055	$17.28	3,204	$0.0041	$13.21	($4.07)	(23.6%)
Wholesale Market Service	kWh	3,142	$0.0052	$16.34	3,204	$0.0052	$16.66	$0.32	2.0%
Rural Rate Protection	kWh	3,142	$0.0010	$3.14	3,204	$0.0010	$3.20	$0.06	1.9%
Debt Retirement Charge	kWh	3,000	$0.0070	$21.00	3,000	$0.0070	$21.00		
TOTAL BILL				**$314.42**			**$311.49**	**($2.93)**	**(0.9%)**

General Service (50-2999 kW) – Bill Impact Summary

Table 11

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
20,164	74	n/a	$109.71	41.7%	$115.72	5.9%
46,278	91	n/a	$114.58	36.6%	$149.22	3.8%
179,400	396	n/a	$202.02	16.5%	$324.91	2.1%
294,372	901	n/a	$346.81	12.7%	$482.03	1.8%
1,182,146	2,241	n/a	$730.98	10.9%	$1,638.15	1.7%

General Service (50-2999 kW) – 396 kW

Table 12

General Service 50 to 2,999 kW **RPP: n/a**

179,400 kWh's

396 kW's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				$42.23			$130.72	$88.49	>100%
Distribution	kW	396	$2.9804	$1,180.24	396	$3.2671	$1,293.77	$113.53	9.6%
Sub-Total (Distribution)				**$1,222.47**			**$1,424.49**	**$202.02**	**16.5%**
Deferral/Variance	kW	396			396	($0.3125)	($123.75)	($123.75)	
Electricity (Commodity)	kWh	187,868	$0.0545	$10,238.79	191,617	$0.0545	$10,443.13	$204.34	2.0%
Transmission - Network	kW	396	$1.4327	$567.35	396	$2.0328	$805.01	$237.66	41.9%
Transmission - Connection	kW	396	$2.2069	$873.93	396	$1.6548	$655.32	($218.61)	(25.0%)
Wholesale Market Service	kWh	187,868	$0.0052	$976.91	191,617	$0.0052	$996.41	$19.50	2.0%
Rural Rate Protection	kWh	187,868	$0.0010	$187.87	191,617	$0.0010	$191.62	$3.75	2.0%
Debt Retirement Charge	kWh	179,400	$0.0070	$1,255.80	179,400	$0.0070	$1,255.80		
TOTAL BILL				**$15,323.12**			**$15,648.03**	**$324.91**	**2.1%**

General Service (3000-4999 kW) – Bill Impact Summary

Table 13

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
1,302,474	3,556	n/a	$3,749.36	57.6%	$4,718.69	4.2%
1,492,765	3,696	n/a	$3,896.96	57.8%	$5,080.81	4.0%
1,939,602	3,758	n/a	$3,962.33	57.9%	$5,701.12	3.6%

General Service (3000-4999 kW) – 3696 kW

Table 14

General Service 3,000 to 4,999 kW **RPP: n/a**

1,492,765 kWh's
3,696 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$558.28			$558.55	$0.27	0.0%
Distribution	kW	3,696	$1.6740	$6,187.10	3,696	$2.7283	$10,083.80	$3,896.69	63.0%
Sub-Total (Distribution)				**$6,745.38**			**$10,642.35**	**$3,896.96**	**57.8%**
Deferral/Variance	kW	3,696			3,696	($0.2122)	($784.29)	($784.29)	
Electricity (Commodity)	kWh	1,563,224	$0.0545	$85,195.68	1,594,422	$0.0545	$86,896.02	$1,700.34	2.0%
Transmission - Network	kW	3,696	$1.6024	$5,922.47	3,696	$2.2736	$8,403.35	$2,480.88	41.9%
Transmission - Connection	kW	3,696	$2.6029	$9,620.32	3,696	$1.9518	$7,213.80	($2,406.52)	(25.0%)
Wholesale Market Service	kWh	1,563,224	$0.0052	$8,128.76	1,594,422	$0.0052	$8,291.00	$162.24	2.0%
Rural Rate Protection	kWh	1,563,224	$0.0010	$1,563.22	1,594,422	$0.0010	$1,594.42	$31.20	2.0%
Debt Retirement Charge	kWh	1,492,765	$0.0070	$10,449.36	1,492,765	$0.0070	$10,449.36		
TOTAL BILL				**$127,625.19**			**$132,706.01**	**$5,080.81**	**4.0%**

USL – Bill Impact Summary

Table 15

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
32,000		Non-res.	$296.76	51.1%	$295.06	9.0%
34,000		Non-res.	$315.16	51.2%	$313.36	9.0%
36,000		Non-res.	$333.56	51.2%	$331.63	9.0%

USL – 36000 kWh

Table 16

Unmetered Scattered Load **RPP: Non-res.**

36,000 kWh's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$14.29			$16.65	$2.36	16.5%
Distribution	kWh	36,000	$0.0177	$637.20	36,000	$0.0269	$968.40	$331.20	52.0%
Sub-Total (Distribution)				**$651.49**			**$985.05**	**$333.56**	**51.2%**
Deferral/Variance	kWh	36,000			36,000	($0.0017)	($61.20)	($61.20)	
Electricity (Commodity)	kWh	37,699	RPP-Non-res.	$2,217.50	38,452	RPP-Non-res.	$2,261.89	$44.39	2.0%
Transmission - Network	kWh	37,699	$0.0035	$131.95	38,452	$0.0050	$190.95	$59.00	44.7%
Transmission - Connection	kWh	37,699	$0.0055	$207.35	38,452	$0.0041	$158.57	($48.78)	(23.5%)
Wholesale Market Service	kWh	37,699	$0.0052	$196.04	38,452	$0.0052	$199.95	$3.91	2.0%
Rural Rate Protection	kWh	37,699	$0.0010	$37.70	38,452	$0.0010	$38.45	$0.75	2.0%
Debt Retirement Charge	kWh	36,000	$0.0070	$252.00	36,000	$0.0070	$252.00		
TOTAL BILL				**$3,694.03**			**$4,025.66**	**$331.63**	**9.0%**

Sentinel Lighting – Bill Impact Summary

Table 17

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
82	0.23	Non-res.	$3.55	>100%	$3.58	51.8%
92	0.25	Non-res.	$3.70	>100%	$3.72	48.4%

Sentinel Lighting – 92 kWh

Table 18

Sentinel Lighting RPP: Non-res.

92 kWh's 0.25 kW's	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT	CHANGE IMPACT %
Monthly Service Charge				$0.46			$2.72	$2.26	>100%
Distribution	kW	0.25	$1.7575	$0.45	0	$7.4289	$1.89	$1.44	>100%
Sub-Total (Distribution)				**$0.91**			**$4.61**	**$3.70**	**>100%**
Deferral/Variance	kW	0			0	($0.3108)	($0.08)	($0.08)	
Electricity (Commodity)	kWh	96	RPP-Non-res.	$4.82	98	RPP-Non-res.	$4.91	$0.09	1.9%
Transmission - Network	kW	0	$1.0860	$0.28	0	$1.5409	$0.39	$0.11	39.3%
Transmission - Connection	kW	0	$1.7418	$0.44	0	$1.3061	$0.33	($0.11)	(25.0%)
Wholesale Market Service	kWh	96	$0.0052	$0.50	98	$0.0052	$0.51	$0.01	2.0%
Rural Rate Protection	kWh	96	$0.0010	$0.10	98	$0.0010	$0.10		
Debt Retirement Charge	kWh	92	$0.0070	$0.64	92	$0.0070	$0.64		
TOTAL BILL				**$7.69**			**$11.41**	**$3.72**	**48.4%**

Street Lighting – Bill Impact Summary

Table 19

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
44	0.16	Non-res.	$3.84	>100%	$3.87	>100%
64	0.16	Non-res.	$3.84	>100%	$3.90	78.5%

Street Lighting – 64 kWh

Table 21

Street Lighting **RPP: Non-res.**

64 kWh's / **0.16 kW's**	**Metric**	**2008 BILL**			**2009 BILL**			**CHANGE IMPACT**	
		Volume	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**		**%**
Monthly Service Charge				$0.16			$2.36	$2.20	>100%
Distribution	kW	0	$1.0613	$0.16	0	$11.6642	$1.81	$1.64	>100%
Sub-Total (Distribution)				**$0.32**			**$4.17**	**$3.84**	**>100%**
Deferral/Variance	kW	0			0	($0.2086)	($0.03)	($0.03)	
Electricity (Commodity)	kWh	67	RPP-Non-res.	$3.35	68	RPP-Non-res.	$3.42	$0.07	2.1%
Transmission - Network	kW	0	$1.0805	$0.17	0	$1.5331	$0.24	$0.07	41.2%
Transmission - Connection	kW	0	$1.7061	$0.26	0	$1.2793	$0.20	($0.06)	(23.1%)
Wholesale Market Service	kWh	67	$0.0052	$0.35	68	$0.0052	$0.36	$0.01	2.9%
Rural Rate Protection	kWh	67	$0.0010	$0.07	68	$0.0010	$0.07		
Debt Retirement Charge	kWh	64	$0.0070	$0.45	64	$0.0070	$0.45		
TOTAL BILL				**$4.97**			**$8.88**	**$3.90**	**78.5%**