INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED

2073 Commerce Park Drive
Innisfil ON L9S 4A2
(S/E Corner Hwy 400 & Innisfil Beach Road)

Tel (705) 431-4321
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Toll Free From 775 Exchange

August 15, 2008

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

Attn: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli

Re: Innisfil Hydro Distribution Systems Limited 2009 Rate Application OEB File No. EB-2008-0233

Innisfil Hydro Distribution Systems Limited is submitting its 2009 Rate Application, in compliance with the OEB Filing Requirements for Transmission and Distribution Applications. The components of the application are as follows:

- Exhibit 1 – Administration
- Exhibit 2 – Rate Base
- Exhibit 3 – Operating Revenue
- Exhibit 4 – Operating Costs
- Exhibit 5 – Deferral and Variance Accounts
- Exhibit 6 – Cost of Capital and Rate of Return
- Exhibit 7 – Calculation of Revenue Deficiency or Surplus
- Exhibit 8 – Cost Allocation
- Exhibit 9 – Rate Design

Further to the Board's RESS filing guidelines, an electronic copy of our full application will be submitted through the OEB e-Filing Services. Two hard copies of the application are being sent by courier.

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

Yours respectfully,

Laurie Ann Cooledge, CMA, CPA
Chief Financial Officer/Treasurer

INNISFIL HYDRO

APPLICATION FOR APPROVAL OF ELECTRICITY DISTRIBUTION RATES

EFFECTIVE MAY 1, 2009

INDEX

SUMMARY OF THE APPLICATION:

Purpose and Need

Innisfil Hydro self nominated for the 2009 rebasing year. Innisfil Hydro is requesting revenue requirement for 2009 includes the recovery of its costs to provide distribution services, its permitted Return on Equity and the funds necessary to service its debt as it transitions to a 60%/40% debt equity ratio by 2010. Innisfil Hydro will be investing in its capital infrastructure over the next five years due to the enhancement and/or replacement of system infrastructure and system expansions in order to meet the demand of new and existing customers in its service territory. This increase is attributed to anticipated growth and replacement of existing aging infrastructure in order to maintain safe and reliable delivery of electricity to our customers. Innisfil Hydro will be seeking additional debt to finance the capital infrastructure anticipated. Innisfil Hydro's forecasts also include increases in OM&A expenses which reflect increases in staff, regulatory costs and other expenses. Additional staffing has resulted due to the increasing accountability, monitoring and reporting demands externally and internally. This has created increased pressures on the already limited staff resources within all departments of Innisfil Hydro. Costs have also increased due to Innisfil Hydro having no internal line staff. The line crew contractor has been sold effective mid 2008. The RFQ and the subsequent evaluation of the market pricing has resulted in double digit price increases.

Through this rate application, Innisfil Hydro seeks the recovery through rates of its proposed 2009 base revenue requirement in the amount of $7,750,434. When its forecasted results for 2009 are considered, Innisfil Hydro estimates that its present rates will produce a deficiency in distribution revenue of $1,071,765 for the 2009 Test Year.

Innisfil Hydro seeks the OEB's approval to revise its electricity distribution rates. The rates proposed to recover its projected revenue requirement and other relief sought are set out in Exhibit 1, Tab 1, Schedule 3, Appendix A and Exhibit 1, Tab 1, Schedule 6 to this Application.

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

Timing

The financial information supporting the Test Year for Innisfil Hydro will be the 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 Innisfil Hydro as needed to enable it to earn the maximum return permitted by the OEB for the 2009 Test Year.

Customer Impact

In preparing this application, Innisfil Hydro has considered the impacts on its customers, with a goal of minimizing those impacts.

With respect to cost allocation, Sentinel and Street Lighting Customers have been adjusted upward to absorb 50% of the adjustment required to align the rate classes to the lower end of the OEB thresholds. The remaining adjustment will be spread out of the next two IRM filings. GS<50 kW rate class has been adjusted downward to the higher end of the OEB threshold in the revenue to cost ratio in this application. Unmetered Scatter Load rate class has been adjusted upward to the low end of the OEB threshold ratio of each rate class defined by the OEB in the OEB's November 28, 2007, Report on Application of Cost Allocation for Electricity Distributors.

Customer impacts including the percentage average Total Bill Impact and average Dollar Impact, which include distribution rates [monthly service charge and volumetric rates], deferral and variance account rate riders to dispose of the balances in the Deferral and Variance Accounts over a two-year period are set out in Table 1, below.

Table 1
AVERAGE TOTAL MONTHLY BILL IMPACT – PERCENT & DOLLAR

Class Average Total Bill Impact	Monthly Volume kWh/kW	Average Total Bill Impact %	Average Dollar Impact
Residential	1000 kWh	7.69%	$9.33
General Service <50 kW	4000 kWh	1.73%	$7.33
General Service >50 kW	30000 kWh 100 kW	3.79%	$126.12
Street Lighting	62 kWh	85.53%	$5.82
Sentinel Lighting	135 kWh	59.42%	$8.62
Unmetered Scattered Load	250 kWh	32.67%	$14.13

Major Issues

The issues to be reviewed in this case, as Innisfil Hydro sees them, are discussed in Exhibit 1, Tab 1, Schedule 7 (Draft Issues List).

Innisfil Hydro also offers comments on the following matters:

- **Capital Structure**

Innisfil Hydro is requesting a decrease in the deemed equity ratio from 46.7% to 43.3% and a increase in the deemed debt ratio from 53.3% to 56.7% consistent with the second year of the phase-in of the shift in Innisfil Hydro's capital structure from 50% to 40% equity and 50% to 60% debt as outlined in the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated December 20, 2006 (the "Cost of Capital Report").

- **Return on Equity**

Innisfil Hydro is utilizing a return on equity of 8.57% consistent with the methodology outlined in Appendix B of the Cost of Capital Report. Innisfil Hydro understands the OEB will be finalizing the return on equity for 2009 rates based on January 2009 market interest rate information.

- **Capital Expenditures**

Innisfil Hydro continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory. This increase in demand comes both from expansion of the Innisfil Hydro distribution system into currently unserviced areas and distribution system upgrades needed in existing areas. Innisfil Hydro has consistently exceeded the OEB's Service Quality Indicators and, as set out in Table 2 below, has targeted to maintain and its performance above the OEB's standard and improve that performance where necessary, in the 2009 Test Year.

Table 2

INNISFIL HYDRO'S SERVICE QUALITY INDICATORS
AVERAGE PERFORMANCE FOR 2006 to 2009

Appointments Met – at the appointed time			
SQI Standard: 90% of the time			
2006	**2007**	**2008 Target**	**2009 Target**
93.46%	100.00%	100.00%	100.00%
Telephone Accessibility – answered in person within 30 seconds			
SQI Standard: 65% of the time			
2006	**2007**	**2008 Target**	**2009 Target**
100.00%	100.00%	100.00%	100.00%
Underground Cable Locates – within 5 working days			
SQI Standard: 90% of the time			
2006	**2007**	**2008 Target**	**2009 Target**
95.18%	92.00%	93.00%	94.00%

Connection of New Services – Low Voltage within 5 working days			
SQI Standard: 90% of the time			
2006	**2007**	**2008 Target**	**2009 Target**
90.40%	97.60%	98.00%	98.00%
Connection of New Services – High Voltage within 10 working days			
SQI Standard: 90% of the time			
2006	**2007**	**2008 Target**	**2009 Target**
NA	100.00%	95.00%	95.00%
Emergency Response – Rural within 60 minutes			
SQI Standard: 80% of the time			
2006	**2007**	**2008 Target**	**2009 Target**
100.00%	100.00%	100.00%	100.00%
Written Responses to Inquiries – within 10 working days			
SQI Standard: 80% of the time			
2006	**2007**	**2008 Target**	**2009 Target**
100.00%	100.00%	100.00%	100.00%

- **Conservation and Demand Management**

Since 2005, Innisfil Hydro has been an active participant in conservation and demand management programming through third tranche and the OPA partnership in keeping with its goal to pursue industry leadership in environmental stewardship.

- **Operating and Maintenance Costs**

Operating and maintenance costs have been updated to reflect the impact of inflation and expected changes in costs. Based on the OEB's Comparison of Ontario Electricity Distributors Costs [EB-2006-0268], as updated with 2007 Data issued on June 24, 2008, Innisfil Hydro's OM&A costs per customer compare favourably with its "Midsize Southern Low & Medium Undergrounding LDCs" cohort. In 2007, the average OM&A cost per customer for the cohort was $272.00 while Innisfil Hydro's cost was $225.00. Over the 3-year average from 2005 to

2007, Innisfil Hydro's cost was $211.00 while the average for the cohort was $260.00. Details of the calculations supporting this analysis are included in Appendix A to this Schedule.

APPENDIX A

COMPARISON OF INNISFIL HYDRO OM&A COSTS TO "Mid-Size Southern Low-Medium Undergrounding LDCs" COHORT GROUPING

SUMMARY OF THE APPLICATION

COMPARISON OF INNISFIL HYDRO OM&A COSTS TO "Midsize Southern Low & Medium Undergrounding LDCs" COHORT GROUPING

Cohort Groupings	Total OM&A	
Midsize Southern Low & Medium Undergrounding LDCs	**Average**	**2007**
Innisfil Hydro Distribution Systems Ltd.	**$ 211.00**	**$ 225.00**
Norfolk Power Distribution Inc.	$ 229.00	$ 255.00
Peninsula West Utilities Ltd.	$ 260.00	$ 203.00
Orillia Power Distribution Corp.	$ 271.00	$ 281.00
Haldimand County Hydro Inc.	$ 293.00	$ 346.00
Fort Erie (CNP)	$ 297.00	$ 323.00
Average for Cohort Group	**$ 260.00**	**$ 272.00**

SOURCE:

Comparison of Ontario Electricity Distributors Costs [EB-2006-0268], updated with 2007 Data Issued June 24, 2007.

IN THE MATTER OF the Ontario Energy Board Act, 1998, being Schedule B to the Energy Competition Act, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an Application by Innisfil Hydro to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2009.

Title of Proceeding:	An application by INNISFIL HYDRO for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2009.
Applicant's Name:	INNISFIL HYDRO
Applicant's Address for Service:	**2073 Commerce Park Drive** Innisfil, ON L9S 4A2
	Attention: Laurie Ann Cooledge, CFO/Treasurer
	Telephone: (705) 431-6870 ext 236 Fax: (705) 431-5901 E-mail: lauriec@innisfilhydro.com

APPLICATION

1. Introduction

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

(b) The Applicant hereby applies to the Ontario Energy Board (the "OEB") pursuant to Section 78 of the *Ontario Energy Board Act, 1998* for approval of its proposed distribution rates and other charges, effective May 1, 2009. A list of requested approvals is set out in Exhibit 1, Tab 1, Schedule 6 below.

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

2. Proposed Distribution Rates and Other Charges

(a) The Schedule of Rates and Charges proposed in this Application is identified in Exhibit 1, Tab 1, Schedule 3, Appendix A attached to this summary and Exhibit 9, Tab 1, Schedule 7, and the material being filed in support of this Application sets out Innisfil Hydro's approach to its distribution rates and charges.

3. Proposed Effective Date of Rate Order

(a) The Applicant requests that the OEB make its Rate Order effective May 1, 2009 in accordance with the Filing Requirements.

(b) In the event that the OEB is unable to provide a Decision and Order in this Application for implementation by the Applicant as of May 1, 2009, the Applicant requests that the OEB issue an interim Order approving the proposed distribution rates and other charges effective May 1, 2009, which may be subject to adjustment based on its final Decision and Order.

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

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

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

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

(iii) the street and sentinel lighting customer classes have total bill impacts exceeding 10% due to the cost allocation methodology within these classes determined with the cost Allocation Report that was filed with the OEB in early 2007. Innisfil Hydro has proposed to move these customer classes to the 70% revenue to cost ratio over the next three years as outlined in Exhibit 8. As a result of very low current revenue to cost ratios, it is to be expected these classes would experience higher increases than the other customer classes. The Unmetered Scattered Load customer class also sees an increase exceeding 10% of the total bill. This is due to the adjustment of the revenue to cost ratio to move this class into the band required by the Cost Allocation Report issued by the Board on November 27, 2007 and load used in the Cost Allocation study;

(iv) the other service charges proposed by the Applicant are the same as those previously approved by the OEB except for a proposed increase in the account setup charge from $15 to $30; and

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

5. Relief Sought

(a) The Applicant applies for an Order or Orders approving the proposed distribution rates and other charges set out in Exhibit 1, Tab 1, Schedule 3, Appendix A to this Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2009, or as soon as possible thereafter; and

(b) In the event that the OEB is unable to provide a Decision and Order in this Application for implementation by the Applicant as of May 1, 2009, the Applicant requests that the OEB issue an interim Order approving the proposed distribution rates and other charges, effective May 1, 2009, which may be subject to adjustment based on its final Decision and Order.

6. Form of Hearing Requested

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

DATED at Toronto, Ontario, this 15th day of August, 2008.

All of which is respectfully submitted,
INNISFIL HYDRO DISTRIBUTION SYSTEMS LTD.

Original Signed by George Shaparew
George Shaparew
President - Innisfil Hydro Distribution Systems Ltd.

SCHEDULE OF PROPOSED RATES AND CHARGES

Schedule of Proposed Tariff of Rates and Charges

Residential		
Service Charge	$	19.52
Distribution Volumetric Rate	$/kWh	0.0218
Regulatory Asset Recovery	$/kWh	0.0010
Retail Transmission Rate – Network Service Rate	$/kWh	0.0052
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0035
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge	$	0.25
General Service Less Than 50 kW		
Service Charge	$	34.28
Distribution Volumetric Rate	$/kWh	0.0121
Regulatory Asset Recovery	$/kWh	0.0008
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0032
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge	$	0.25
General Service Greater Than 50 kW		
Service Charge	$	360.08
Distribution Volumetric Rate	$/kW	4.2032
Regulatory Asset Recovery	$/kW	0.2730
Retail Transmission Rate – Network Service Rate	$/kW	1.9079
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2701
Retail Transmission Rate – Network Service Rate-Interval Metered	$/kW	1.8479
Retail Transmission Rate – Line and Transformation Connection Service Rate-Interval Metered	$/kW	1.8623
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge (if applicable)	$	0.25
Unmetered Scattered Load		
Service Charge	$	23.24
Distribution Volumetric Rate	$/kW	0.0433
Regulatory Asset Recovery	$/kW	0.0011
Retail Transmission Rate – Network Service Rate	$/kW	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.0032
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge (if applicable)	$	0.25
Street Lighting		
Service Charge (per connection)	$	3.00
Distribution Volumetric Rate	$/kW	23.6035
Regulatory Asset Recovery	$/kW	0.2832
Retail Transmission Rate – Network Service Rate	$/kW	1.4389
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9818
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per customer)	$	4.50
Distribution Volumetric Rate	$/kW h	22.8118
Regulatory Asset Recovery	$/kW h	0.3517
Retail Transmission Rate – Network Service Rate	$/kW	1.4462
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0023
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears certificate	$	15.00
Easement Letter	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special meter reads	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	15.00
Collection of account charge – no disconnection - after regular hours	$	165.00
Disconnect/Reconnect Charge - At Meter during Regular Hours	$	40.00
Disconnect/Reconnect Charge - 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	$	40.00
Install/Remove load control device – after regular hours	$	185.00
Temporary service – installs and remove – overhead – no transformer	$	500.00
Temporary service – installs and remove – underground – no transformer	$	300.00
Temporary service – install and 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)

Loss Factor

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0746
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0639
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

DISTRIBUTOR LICENCE:

A copy of Innisfil Hydro's Electricity Distribution Licence ED-2002-0520, issued on November 6, 2003, accompanies this application as Appendix A.

APPENDIX A

COPY OF INNISFIL HYDRO DISTRIBUTION LICENCE

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

RP-2002-0191 1
EB-2002-0520

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.1998, c.15, Schedule B; 2

AND IN THE MATTER OF an application by Innisfil Hydro Distribution Systems Ltd. for renewal of its electricity distribution licence. 3

By delegation, before: Mark C. Garner 4

DECISION AND ORDER 5

Innisfil Hydro Distribution Systems Ltd. (the "Applicant") filed an application dated December 10, 2002 with the Ontario Energy Board under section 60 of the *Ontario Energy Board Act, 1998*, c. 15, Schedule B (the "Act") for renewal of its electricity distribution licence. 6

The Board's Notice of Application and Notice of Proposal for renewal of its electricity distribution licence was published on June 25, 2003. Hydro One Networks ("Networks") responded to the Notice. Networks provided a written submission in response to the Notice. 7

Consideration has been given to the application and the written submission by Networks regarding the definition of the Applicant's service area. After considering the application, I find that it is in the public interest to issue the electricity distribution licence under Part V of the Act. 8

IT IS THEREFORE ORDERED THAT: 9

The application by Innisfil Hydro Distribution Systems Ltd. to renew its electricity distribution licence is granted, on such conditions as are contained in the licence [oeb:12MD7-0:1]. 10

DATED at Toronto, November 6, 2003.

ONTARIO ENERGY BOARD

Peter H. O'Dell
Assistant Secretary

Electricity Distribution Licence

ED-2002-0520

Innisfil Hydro Distribution Systems Ltd.

Valid Until
November 5, 2023

Mark C. Garner
Secretary
Ontario Energy Board

Date of Issuance: November 6, 2003

Ontario Energy Board	Commission de l'Énergie de l'Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
26th. Floor	26e étage
Toronto, ON M4P 1E4	Toronto ON M4P 1E4

1 Definitions 1

In this Licence: 2

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which 3
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; 4

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means 5
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 serv- 6
ices 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 7
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; 8

"**Licensee**" means: Innisfil Hydro Distribution Systems Ltd.; 9

"**Market Rules**" means the rules made under section 32 of the Electricity Act; 10

"**Performance Standards**" means the performance targets for the distribution and connec- 11
tion 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 per- 12
mitted to charge;

"**regulation**" means a regulation made under the Act or the Electricity Act; 13

"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; 14

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

"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; 16

"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. 17

2 Interpretation 18

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. 19

3 Authorization 20

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

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

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 23

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. 24

4 Obligation to Comply with Legislation, Regulations and Market Rules 25

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. 26

4.2 The Licensee shall comply with all applicable Market Rules. 27

5 Obligation to Comply with Codes 28

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: 29

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters; 30

b) the Distribution System Code; 31

c) the Retail Settlement Code; and 32

d) the Standard Supply Service Code. 33

5.2 The Licensee shall: 34

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 35

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. 36

6 Obligation to Provide Non-discriminatory Access 37

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. 38

7 Obligation to Connect 39

7.1 The Licensee shall connect a building to its distribution system if: 40

a) the building lies along any of the lines of the distributor's distribution system; and 41

b) the owner, occupant or other person in charge of the building requests the connection in writing. 42

7.2 The Licensee shall make an offer to connect a building to its distribution system if: 43

a) the building is within the Licensee's service area as described in Schedule 1; and 44

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

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. 46

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. 47

8 Obligation to Sell Electricity 48

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. 49

9 Obligation to Maintain System Integrity 50

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. 51

10 Market Power Mitigation Rebates 52

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence. 53

11 Distribution Rates 54

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. 55

12 Separation of Business Activities 56

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. 57

13 Expansion of Distribution System 58

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. 59

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. 60

14 Provision of Information to the Board 61

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. 62

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. 63

15 Restrictions on Provision of Information 64

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. 65

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: 66

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence; 67

b) for billing, settlement or market operations purposes; 68

c) for law enforcement purposes; or 69

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator. 70

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. 71

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. 72

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. 73

16 Customer Complaint and Dispute Resolution 74

16.1 The Licensee shall: 75

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner; 76

b) publish information which will make its customers aware of and help them to use its dispute resolution process; 77

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; 78

d) give or send free of charge a copy of the process to any person who reasonably requests it; and 79

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. 80

17 Term of Licence 81

17.1 This Licence shall take effect on November 6, 2003 and expire on November 5, 2023. The term of this Licence may be extended by the Board. 82

18 Fees and Assessments 83

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board. 84

19 Communication 85

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. 86

19.2 All official communication relating to this Licence shall be in writing. 87

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee: 88

a) when delivered in person to the addressee by hand, by registered mail or by courier; 89

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and 90

c) when received by facsimile transmission by the addressee, according to the sender's transmission report. 91

20 Copies of the Licence 92

20.1 The Licensee shall: 93

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 94

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. 95

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA 96

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. 97

1 The Town of Innisfil as of January 1, 1994. 98

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE 100

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. 101

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. 102

SCHEDULE 3 LIST OF CODE EXEMPTIONS 103

This Schedule specifies any specific Code requirements from which the Licensee has been exempted. 104

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. 105

APPENDIX A MARKET POWER MITIGATION REBATES 106

1 Definitions and Interpretation 107

In this Licence, 108

"embedded distributor" means a distributor who is not a market participant and to whom a 109
host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose gen- 110
eration facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes elec- 111
tricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IMO includes interim pay- 112
ments made by the IMO.

2 Information Given to IMO 113

a Prior to the payment of a rebate amount by the IMO to a distributor, the distributor shall provide 114
the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with information in respect of the volumes of electricity withdrawn by the distributor from the IMO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail 115
Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed 116
price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*.

b Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity con- 117
sumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IMO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 118

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.* 119

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. 120

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. 121

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. 122

3 Pass Through of Rebate 123

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: 124

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; 125

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 126

c embedded distributors to whom the distributor distributes electricity. 127

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. 128

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: 129

"ONTARIO POWER GENERATION INC. rebate" 130

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. 131

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party. 132

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. 133

CONTACT INFORMATION:

FOR INNISFIL HYDRO DISTRIBUTION SYSTEMS LTD.:

PRESIDENT: George Shaparew
Direct line: 705-431-6870 ext 233
Direct Fax: 705-646-9961
Direct Email: georges@innisfilhydro.com

CFO/TREASURER: Laurie Ann Cooledge
Direct line: 705-431-6870 ext 236
Direct Fax: 705-646-9961
Direct Email: lauriec@innifilhydro.com

SPECIFIC APPROVALS REQUESTED:

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

- Approval to rates and charges effective May 1, 2009 to recover a revenue requirement of $8,241,691 which includes a revenue deficiency of $1,071,765, as set out in Exhibit 1, Tab 2, Schedule 3. The schedule of proposed rates is set out in Exhibit 1 Tab 1 Schedule 3 Appendix A and Exhibit 9 Tab 1 Schedule 7;

- Approval of the Applicant's proposed change in capital structure, decreasing the Applicant's deemed common equity component from 46.7% to 43.3% and increasing the deemed debt component from 53.3% to 56.7%, as set out in Exhibit 6, Tab 1, Schedule 3, consistent with Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors dated December 20, 2006;

- Approval of the proposed loss factor as set out in Exhibit 4, Tab 2, Schedule 9;

- Approval to continue the Specific Service Charges and Transformer Allowance approved in the OEB's Decision and Order in the matter of Innisfil Hydro's 2006 distribution rates [RP-2005-0020/EB-2005-0382],

- Approval to continue to recover $0.28 as a rate rider per month per meter per residential and general service customers arising from costs associated with the smart metering infrastructure.

- Approval to dispose of the following Deferral and Variance Account Balances as at December 31, 2007 plus interest to April 30, 2009 over a 2-year period using the method of recovery described in Exhibit 5, Tab 1, Schedule 1:

  - 1508 Other Regulatory Assets
  - 1550 Low Voltage Variance Account

DRAFT ISSUES LIST:

Innisfil Hydro would expect, based on previous regulatory experience and other hearings, that the following matters pertaining to the 2009 Test Year may constitute issues in this Application:

- Innisfil Hydro's current deemed capital structure is 53.3% debt and 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. Innisfil Hydro is requesting a change in its deemed capital structure resulting in a decrease in the deemed equity ratio from 46.7% to 43.3% and an increase in the deemed debt ratio from 53.3% to 56.7% consistent with the phase-in of the OEB's mandated 60% debt/40% equity ratio.

- Innisfil Hydro 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. Innisfil Hydro understands the OEB will be finalizing the return on equity for 2009 rates based on January 2009 market interest rate information.

- Innisfil Hydro continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory consistent with Innisfil Hydro's asset management plan. This increase is attributed to growth and replacement of existing aging infrastructure in order to maintain safe and reliable delivery of electricity to our customers.

- Operating and maintenance costs have been updated to reflect the impact of inflation, expected changes in costs and increased labour force due to succession planning, growth and regulatory requirements. Also creating upward cost pressures is the forced change of line crew contractor due to the sale of the business and the higher market price for these services.

- Innisfil Hydro adjusted the percentage of revenue recovered from the rate classes in accordance with the results of the Cost Allocation Filing. With the requested rates, recoveries from the individual classes fall within the Board recommended ranges outlined in the Board's report except for the streetlight and sentinel light classes. A move toward the recommended ranges for these two classes will begin in the 2009 rates and will be continued in the following two IRM applications.

- Innisfil Hydro, along with other members of the CHEC group, have met with the Ministry of Energy staff to arrange approval to begin installation of smart meters in our service territory in order to meet the Government's 2010 timeline. Innisfil Hydro is requesting continuation of the rate rider for smart metering infrastructure in the 2009 Rate Application and expects to submit an application at a later date for a revised Smart Meter Rate Rider once the process for Innisfil Hydro becomes more definite with respect to inclusion in the Ministry Regulations for the procurement of Smart Meters.

- Due to Affiliate Relationship Codes compliance issues, Innisfil Hydro is no longer able to provide customer service support to its affiliate, Innisfil Energy Services Limited which has resulted in a loss of revenue for 2009 of approximately $50,000.

PROCEDURAL ORDERS/MOTIONS/NOTICES:

On March 12, 2007, the OEB issued a Report titled "LDC Screening Methodology to Establish a Rebasing Schedule for Electricity LDCs". The purpose of that Report was "to describe the criteria to be considered in determining which electricity distributors to engage in proceedings before the Board for rebasing to establish rates for each of the years 2009, 2009 and 2010" and to establish the next steps and timelines for filing. Section 3.3 of that Report provided an opportunity for LDCs to "self-nominate" to be rebased in a particular year.

On April 11, 2008, Innisfil Hydro filed a self-nomination request for rebasing in 2009. Subsequently, in Board File No. EB-2006-0330, the OEB issued its list of distributors that will be rebased in 2009 – the list included Innisfil Hydro Distribution Systems Ltd.

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

ACCOUNTING ORDERS REQUESTED:

Innisfil Hydro is not requesting Accounting Orders in this proceeding.

COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS:

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

DISTRIBUTION SERVICE TERRITORY AND DISTRIBUTION SYSTEM:

Description of Distributor:

COMMUNITY SERVED:	Town of Innisfil
TOTAL SERVICE AREA:	292 sq km
RURAL SERVICE AREA:	230 sq km
DISTRIBUTION TYPE:	Electricity distribution
SERVICE AREA POPULATION:	32,007
MUNICIPAL POPULATION:	32,007
BOUNDARIES:	West: as identified in service area maps
	North: as identified in service area maps
	East: as identified in service area maps
	South: as identified in service area maps

Maps of the Innisfil Hydro Distribution Service Territory and schematic diagrams of the distribution system accompanies this Schedule as Appendix A.

APPENDIX A

MAPS OF DISTRIBUTION SERVICE TERRITORY AND DISTRIBUTION SYSTEM

MAPS OF DISTRIBUTION SERVICE TERRITORY AND DISTRIBUTION SYSTEM

The first map outlined area represents the Town of Innisfil. The subsequent maps outline Innisfil Hydro's distribution system.

TOWN OF INNISFIL
KEMPENFELT BAY
SANDY COVE ACRES
STROUD
CHURCHILL
BIG BAY POINT
COOKSTOWN
GILFORD
LEFROY
ALCONA
Legend
PROVINCIAL HIGHWAY
COUNTY ROAD
LOCAL ROAD
PRIVATE ROAD
UNASSUMED ROAD
UNOPENED ROAD
911 WATER ACCESS
STREAMS
WATERBODY
PARAMEDIC STATION
POLICE STATION
AIRPORT
FIREHALL
HOSPITAL
MUNICIPAL BORDER
LOT AND CONCESSION
COUNTY OF SIMCOE
For the Greater Good
Roads shown may not be maintained by municipality.
0 0.5 1 2 3 4 km
SIMCOE COUNTY LAND INFORMATION NETWORK COOPERATIVE
LINC
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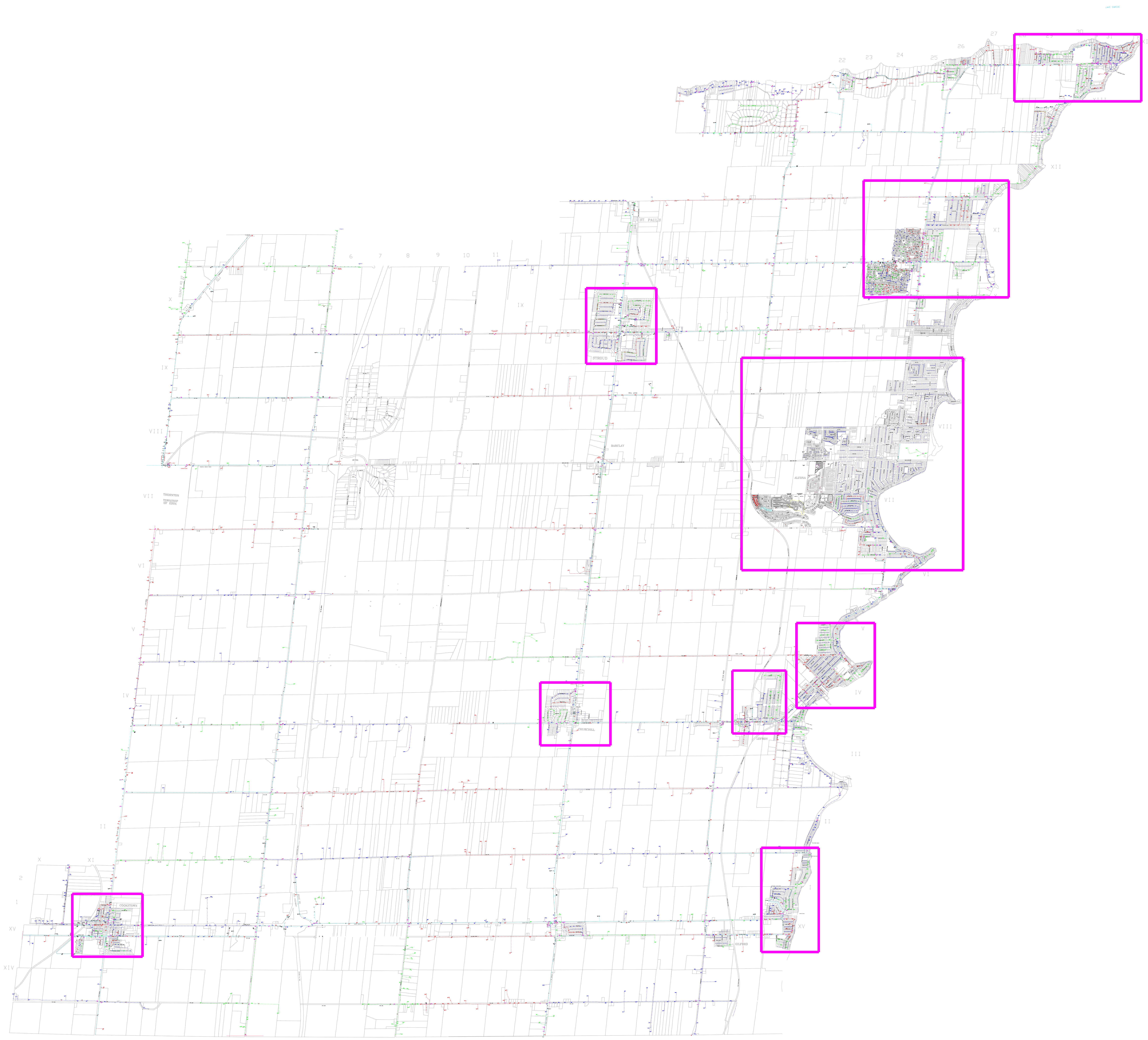
Produced by: County of Simcoe GIS Division (705) 726-9300 ext. 1253



LEGEND

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○ - SWITCH

INNISFIL HYDRO

REG. PLANS	ORIENTATION

DRAWN	CHECKED	DATE
MM	.	23/4/08
REV.	DATE	BY
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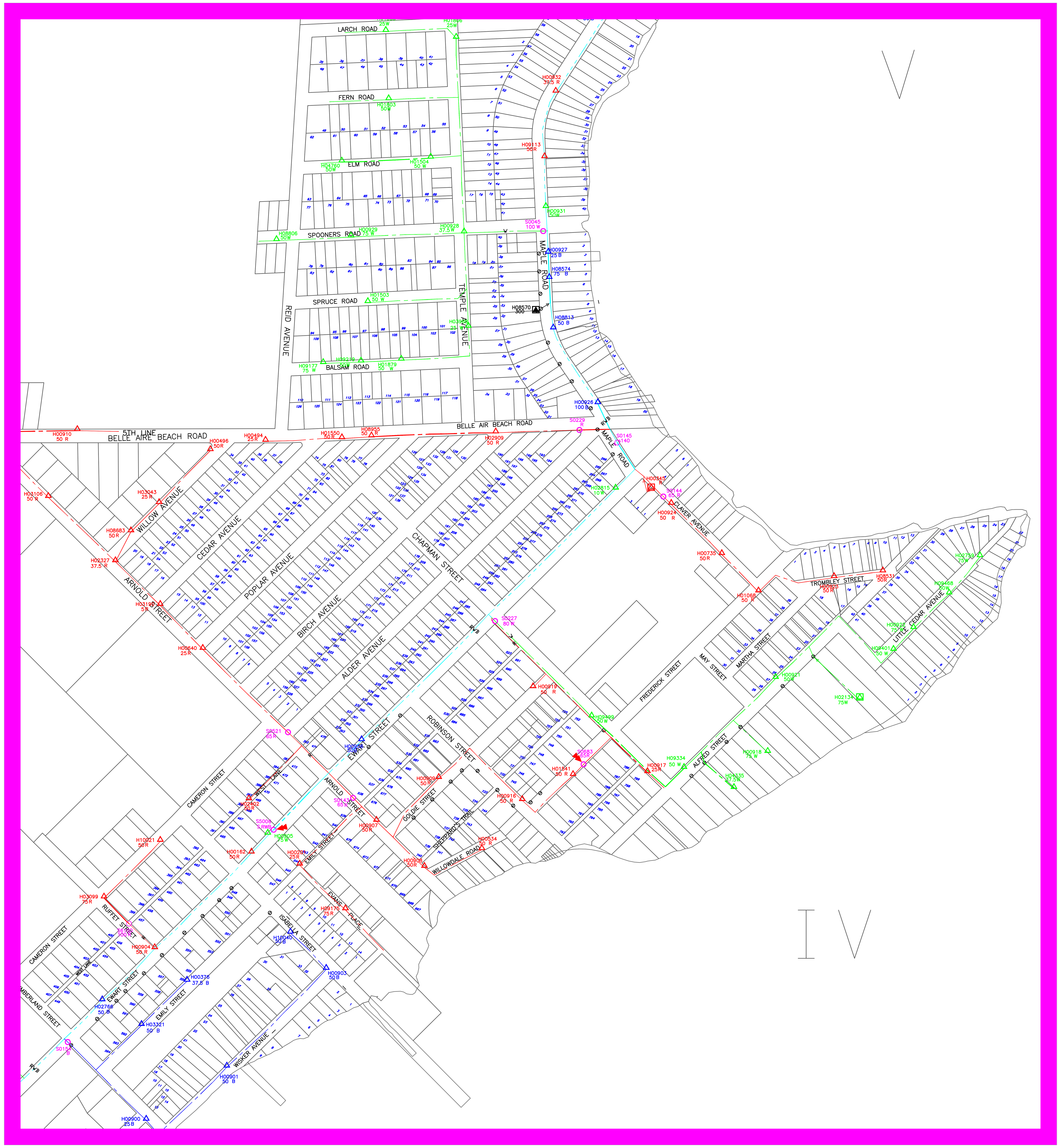
DWG. SCALE
N.T.S

DWG. NAME:
URBAN CENTRES
REFERENCE - TOWN
OF INNISFIL



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INNISFIL HYDRO

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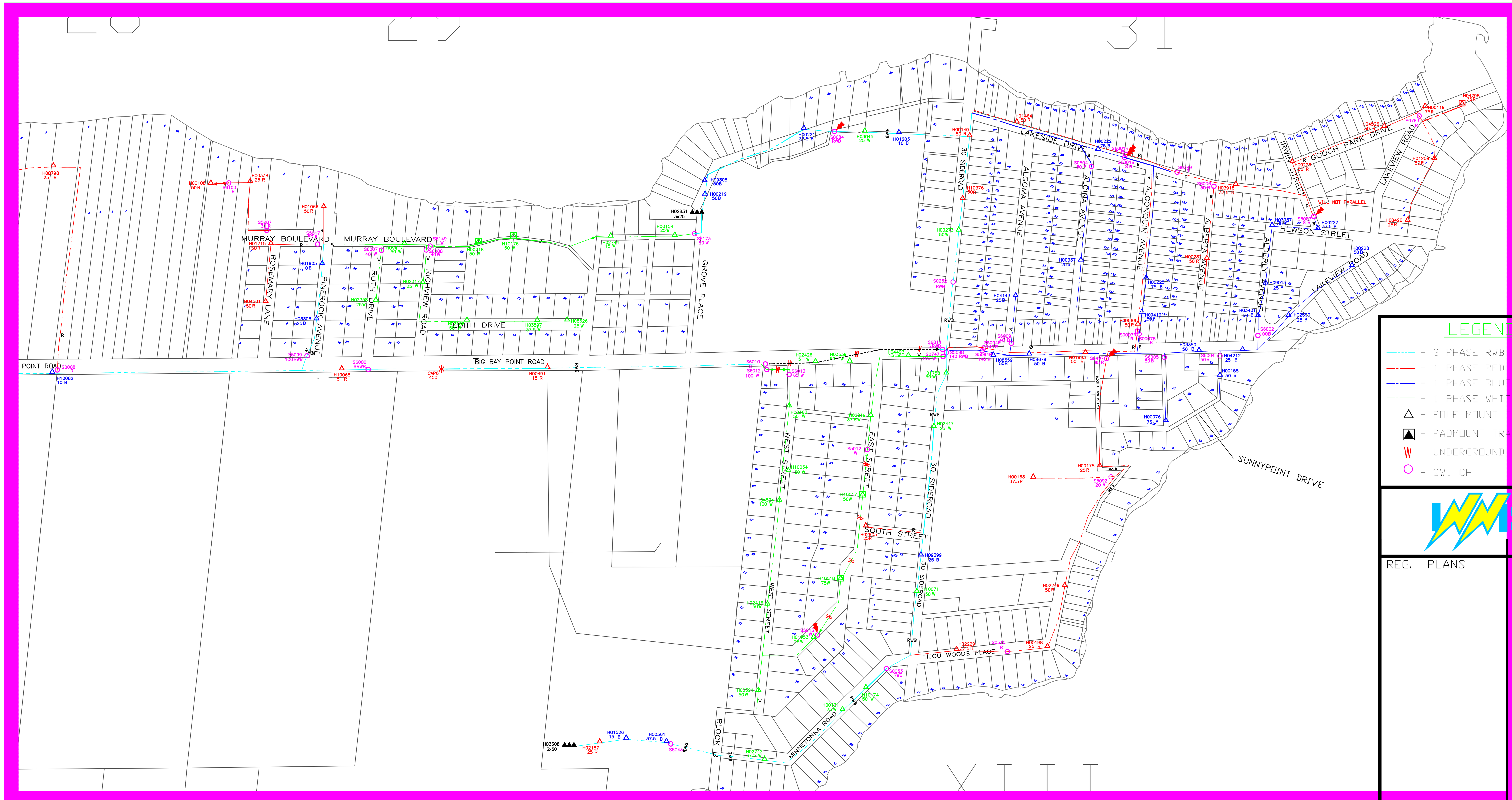
DWG. NAME:
8.32KV - BELL EWART (URBAN)



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INNISFIL HYDRO

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DWG. NAME:
8.32KV - BIG BAY POINT (URBAN)

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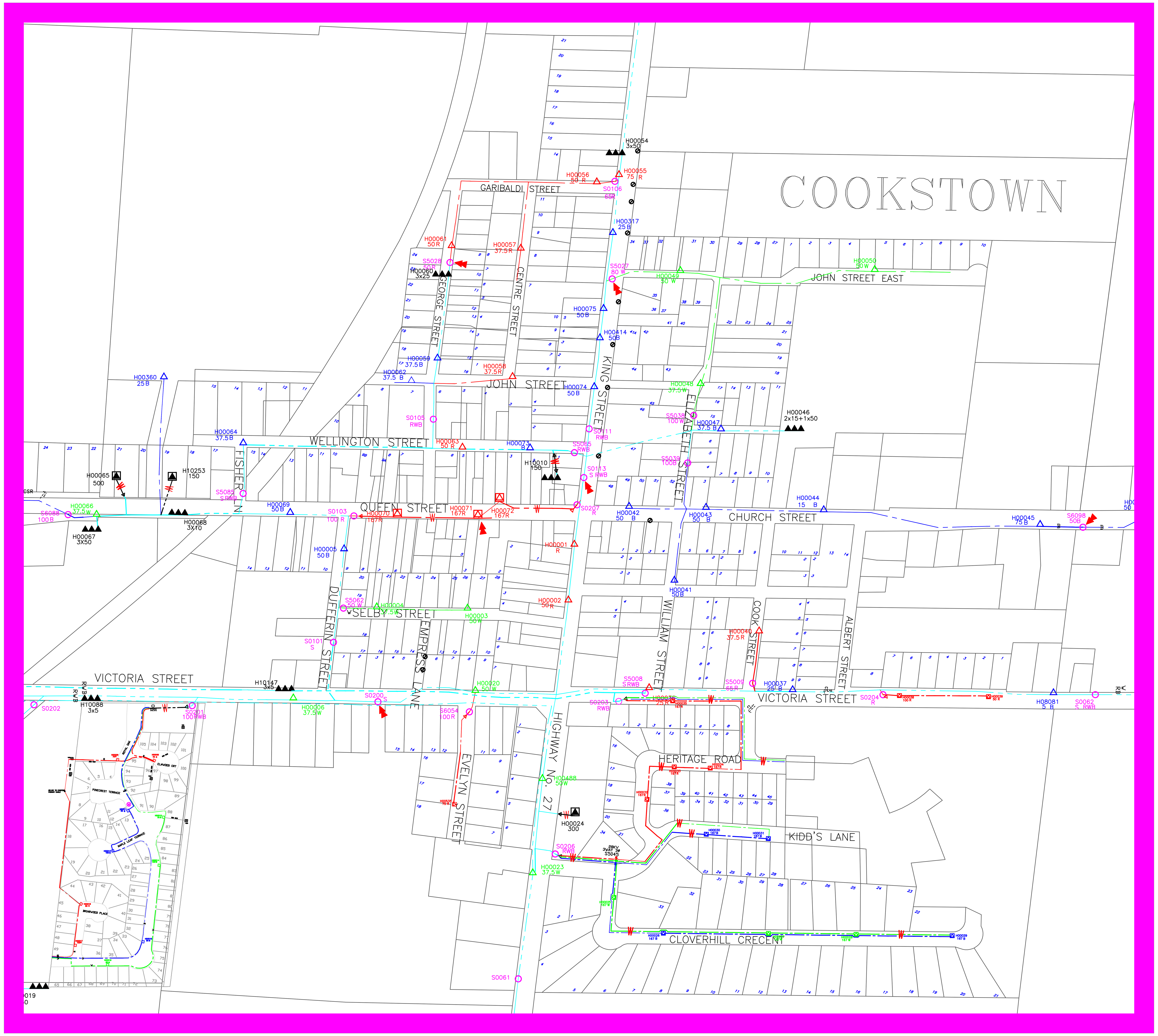
DWG. NAME:
8.32KV - CHURCHILL (URBAN)



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INNISFIL HYDRO

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DWG. SCALE
N.T.S

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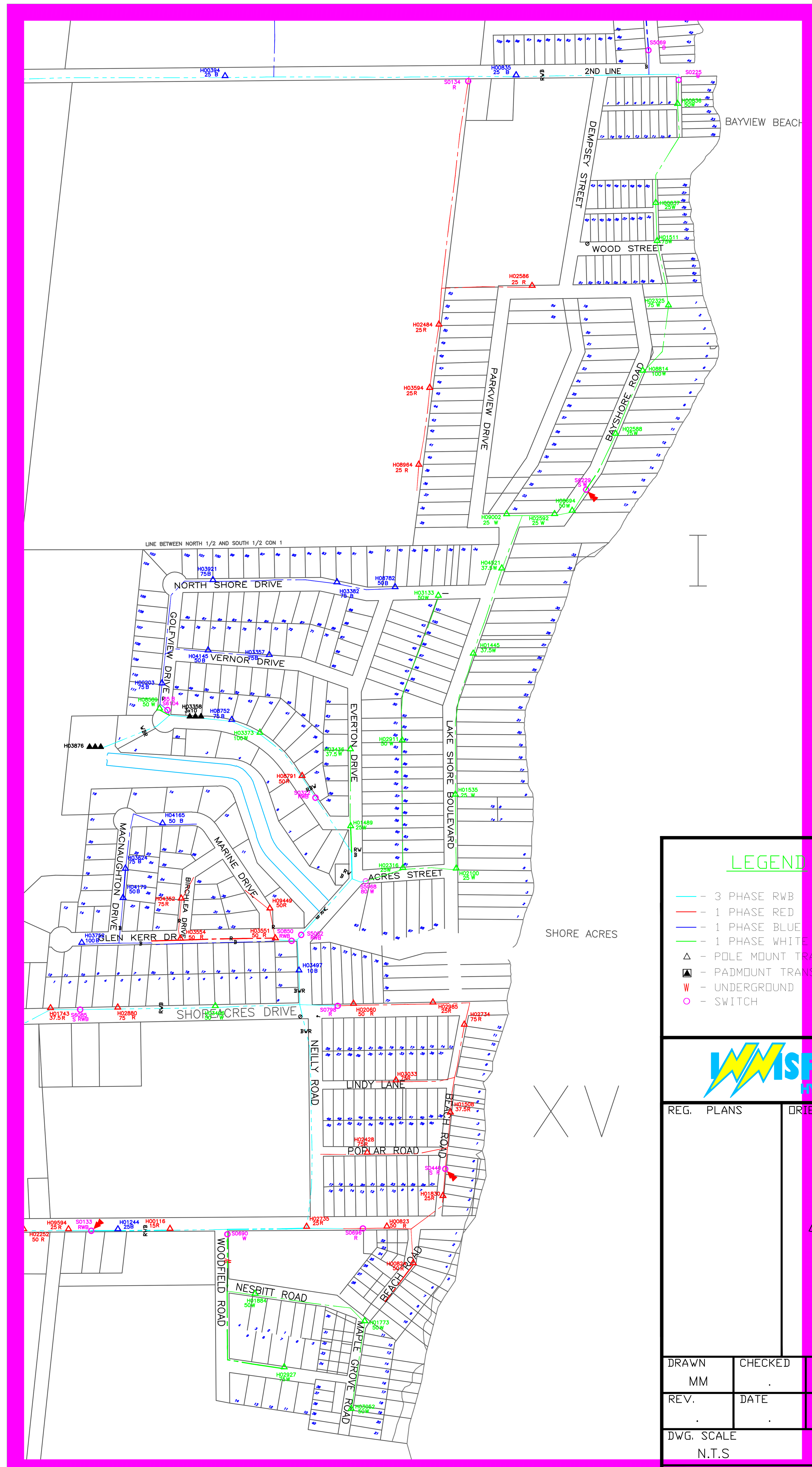
8. 32KV - COOKSTOWN (URBAN)



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INNISFIL HYDRO

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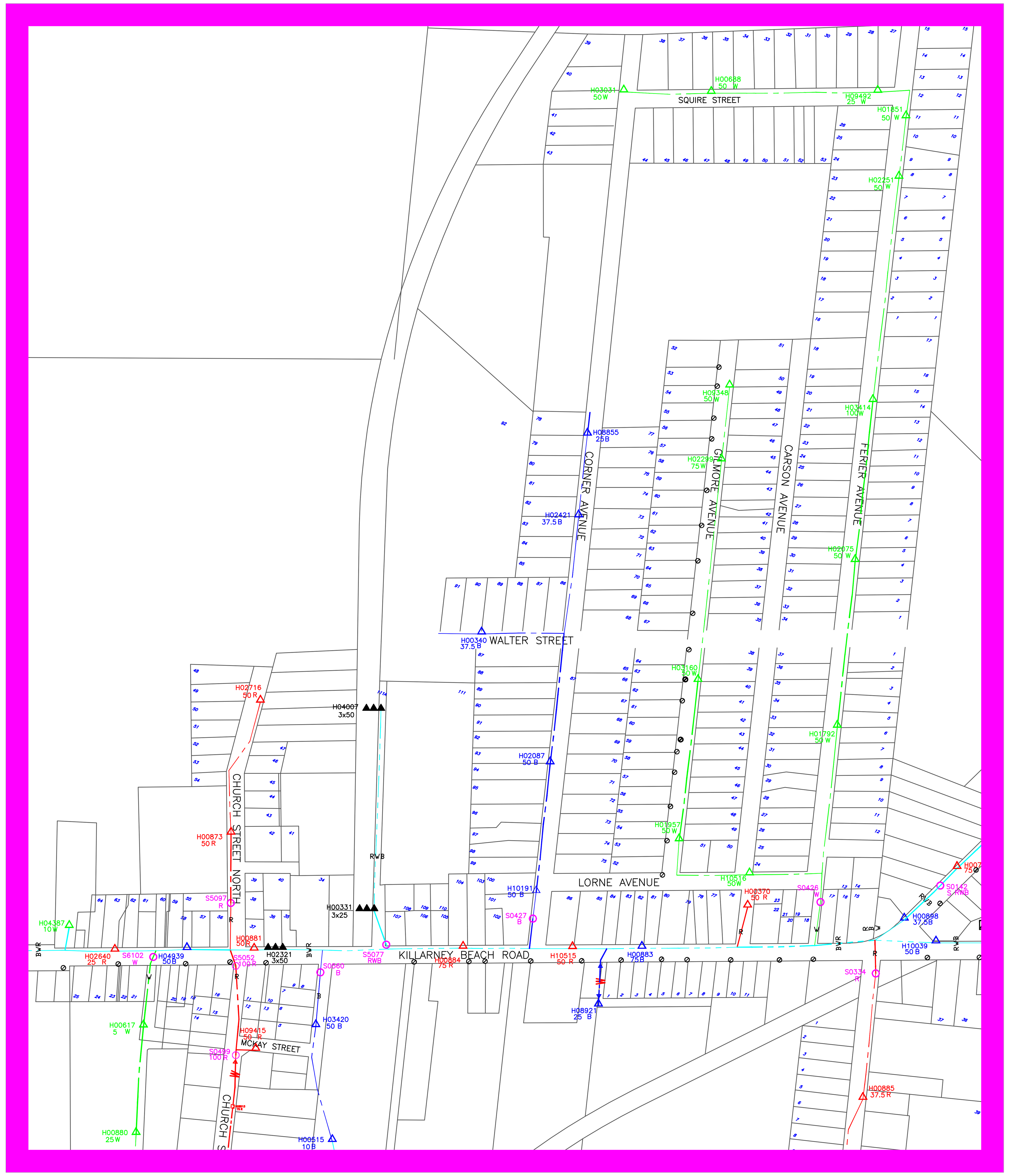
DWG. NAME:

8. 32KV - GILFORD
(URBAN)



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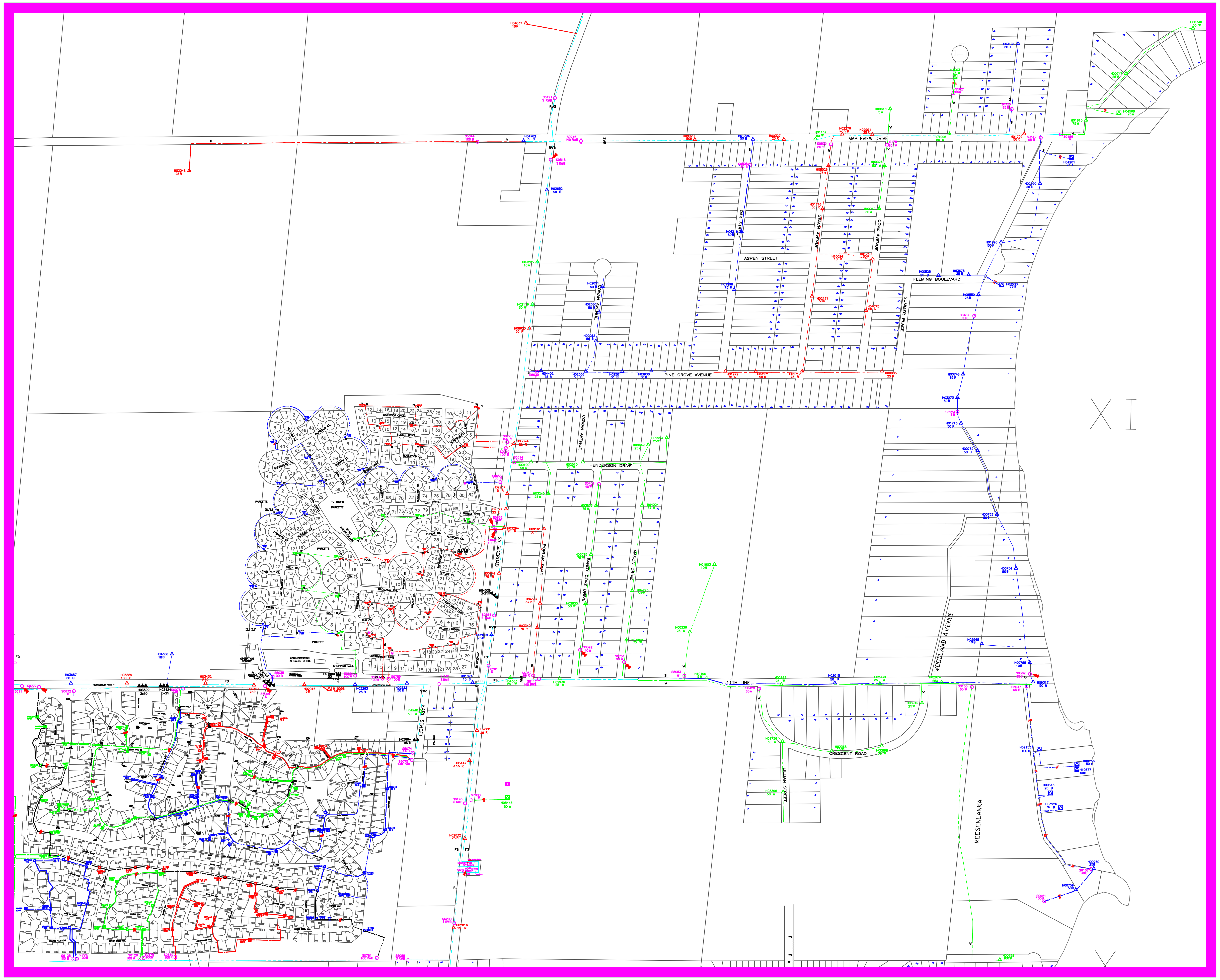
8. 32KV - LEFROY
(URBAN)



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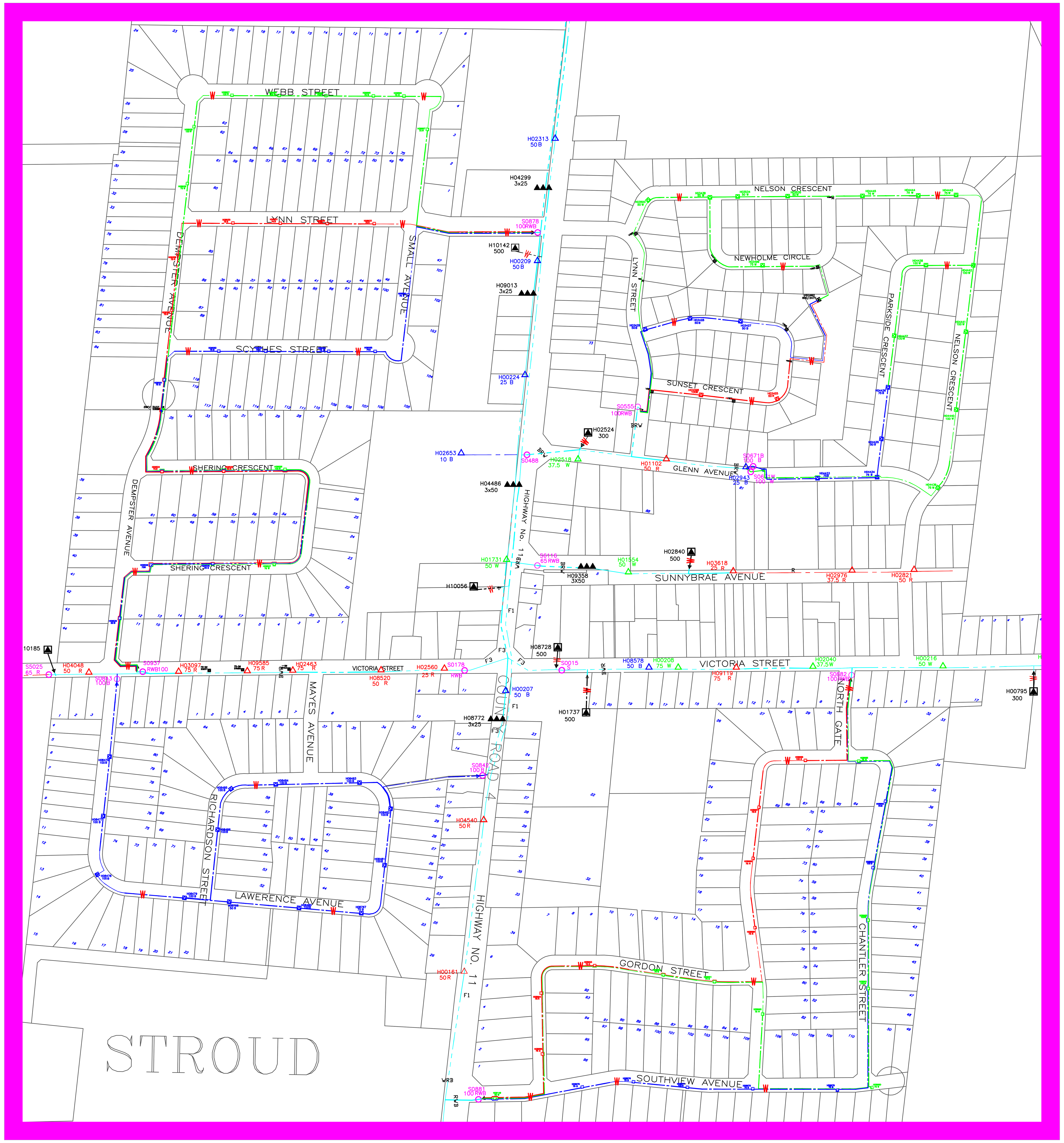
DWG. NAME:
8.32KV - SANDY COVE (URBAN)



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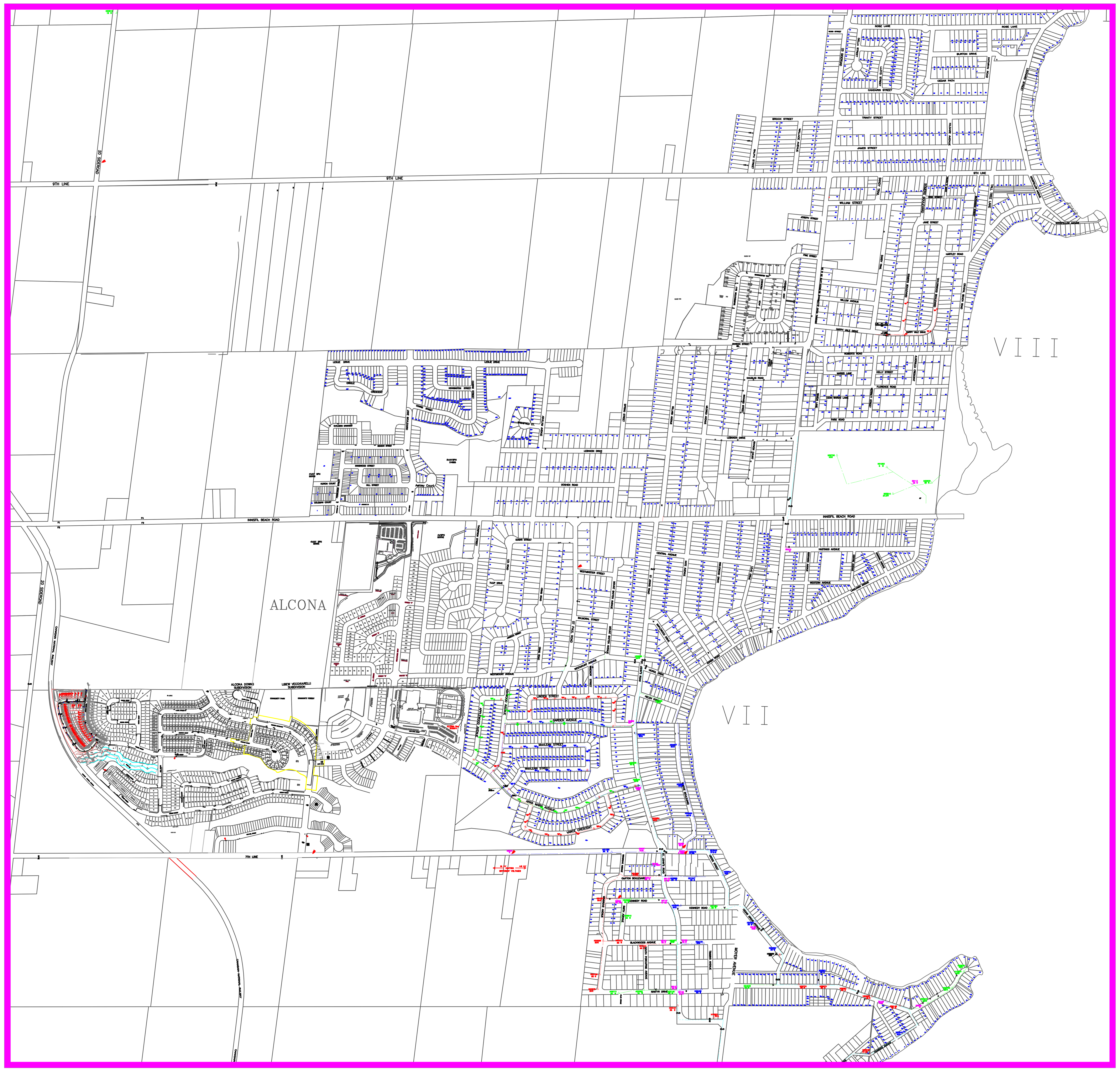
8. 32KV - STROUD
(URBAN)



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INNISFIL HYDRO

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DWG. SCALE
N.T.S

DWG. NAME:
8. 32KV - ALCONA
(URBAN)

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INNISFIL HYDRO

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N.T.S

DWG. NAME:
27.6KV ALCONA - (URBAN)

LEGEND

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INNISFIL HYDRO

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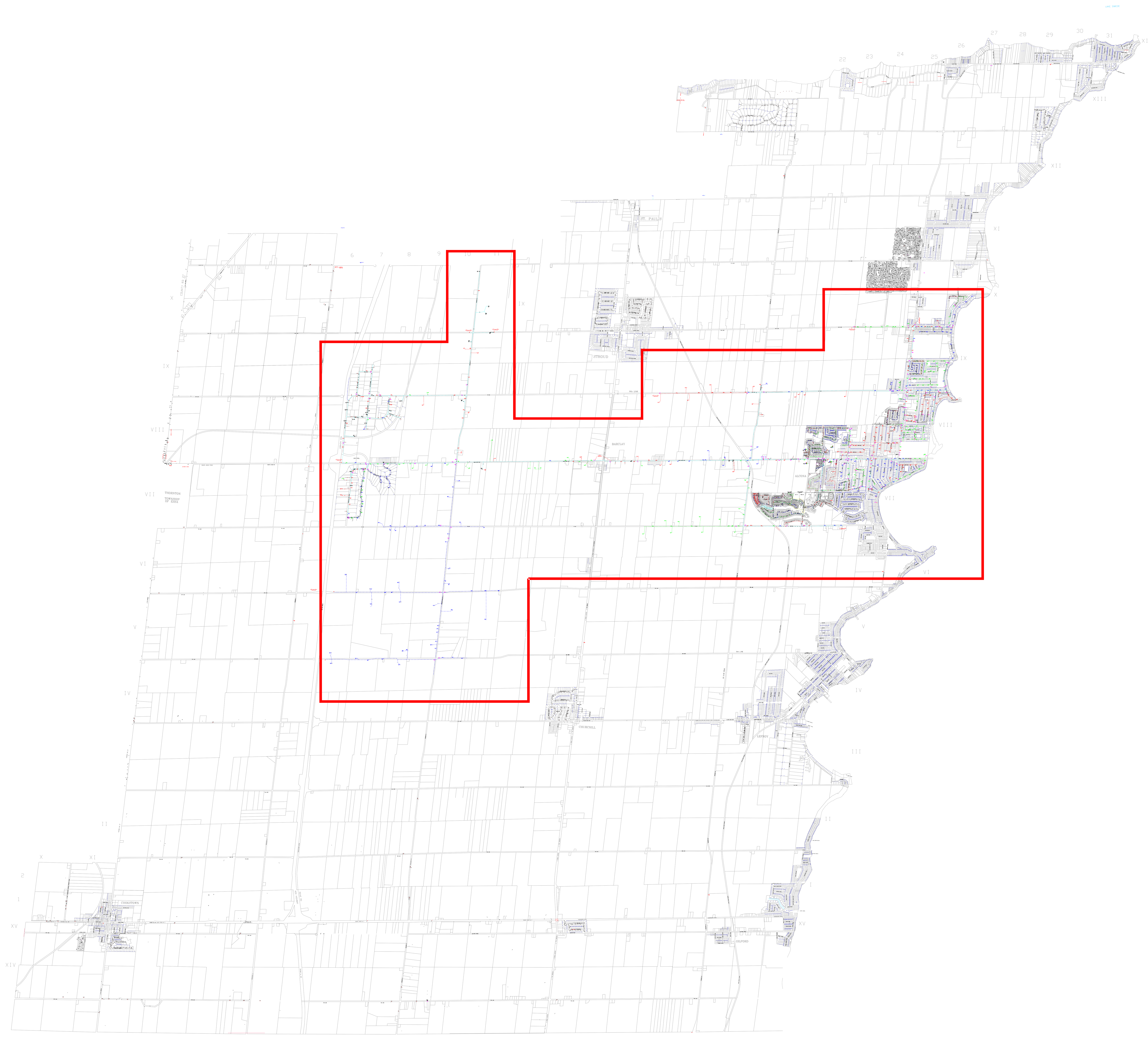
DWG. SCALE
N.T.S

DWG. NAME:
8.32KV URBAN AND RURAL - TOWN OF INNISFIL



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INNISFIL HYDRO

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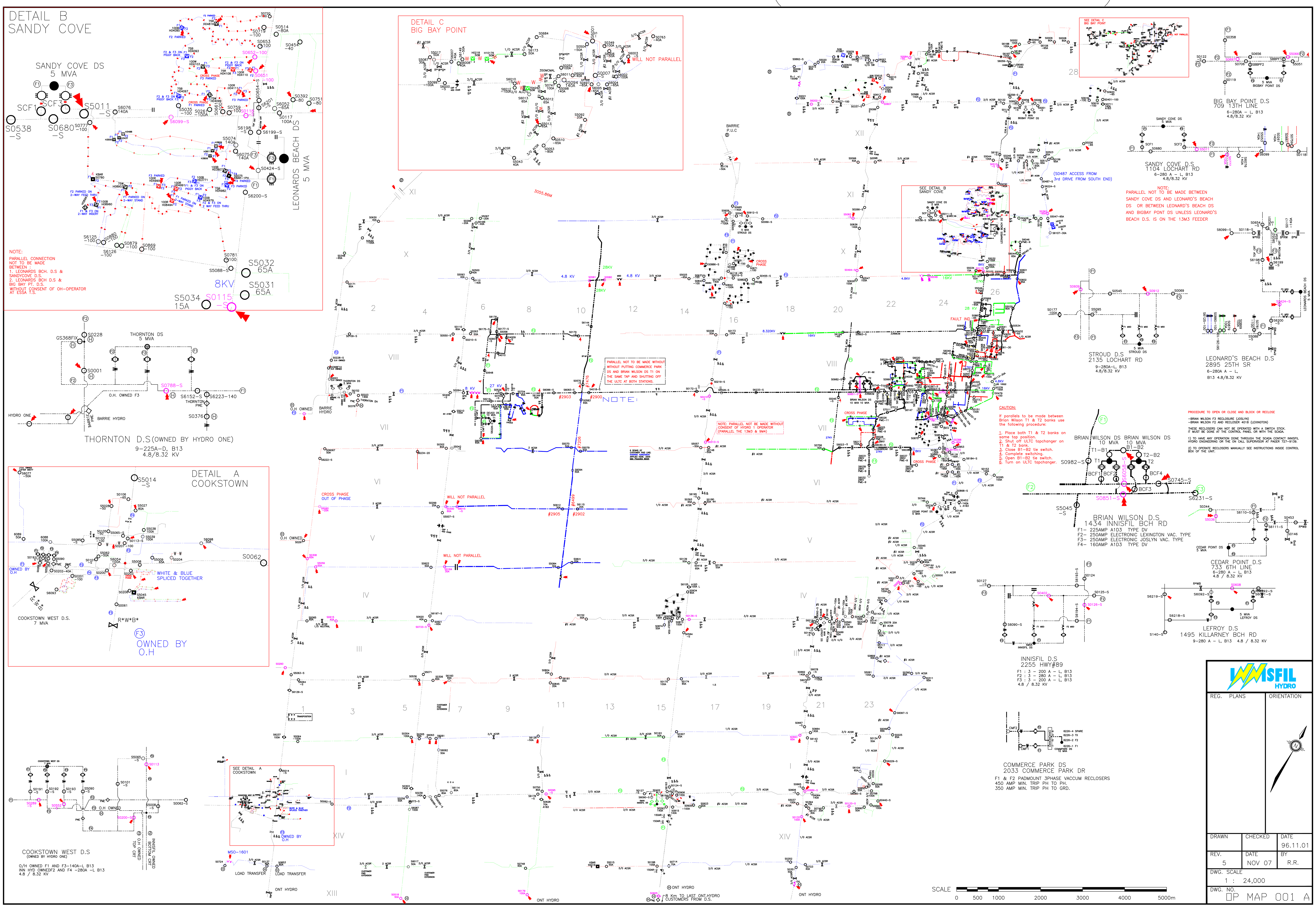
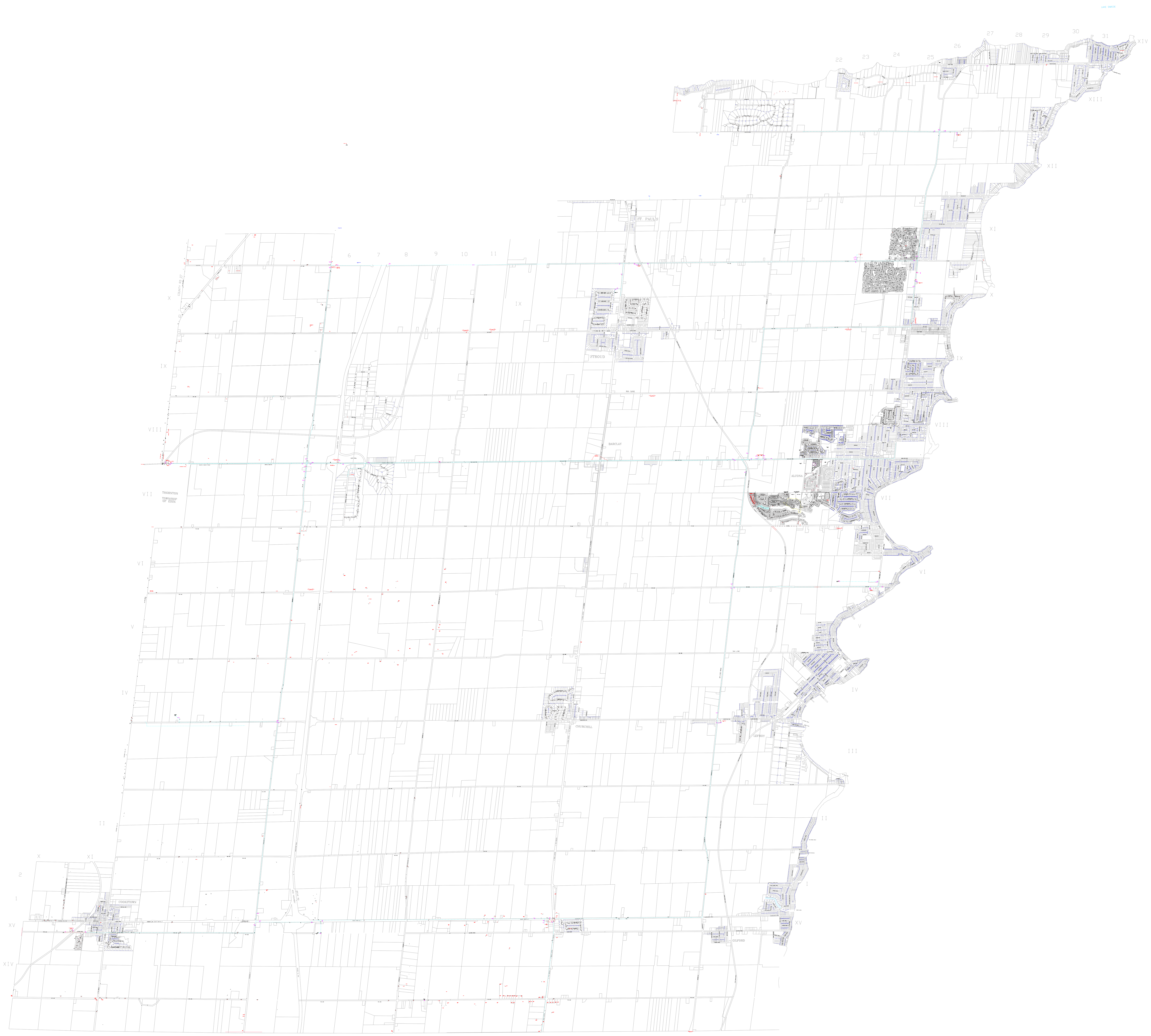
DWG. SCALE
N.T.S

DWG. NAME:
27.6KV URBAN AND RURAL - TOWN OF INNISFIL



DISTRIBUTION OPERATING MAP (8.320KV+27.6KV)
DETAIL B
SANDY COVE
SANDY COVE DS
5 MVA
LEONARDS BEACH DS
5 MVA
NOTE:
PARALLEL CONNECTION NOT TO BE MADE BETWEEN:
1. LEONARDS BCH. D.S & SANDYCOVE D.S
2. LEONARDS BCH D.S & BIG BAY PT. D.S.
WITHOUT CONSENT OF OH-OPERATOR AT ESSA T.S.
DETAIL C
BIG BAY POINT
WILL NOT PARALLEL
THORNTON DS
5 MVA
THORNTON D.S(OWNED BY HYDRO ONE)
9-225A-D, B13
4.8/8.32 KV
DETAIL A
COOKSTOWN
WHITE & BLUE SPLICED TOGETHER
COOKSTOWN WEST D.S.
7 MVA
OWNED BY O.H
COOKSTOWN WEST D.S
BIG BAY POINT D.S
709 13TH LINE
6-280A - L B13
4.8/8.32 KV
SANDY COVE D.S
1104 LOCHART RD
6-280 A - L B13
4.8/8.32 KV
NOTE:
PARALLEL NOT TO BE MADE BETWEEN SANDY COVE DS AND LEONARD'S BEACH DS OR BETWEEN LEONARD'S BEACH DS AND BIGBAY POINT DS UNLESS LEONARD'S BEACH D.S. IS ON THE 13M3 FEEDER
STROUD D.S
2135 LOCHART RD
9-280A-L B13
4.8/8.32 KV
LEONARD'S BEACH D.S
2895 25TH SR
6-280A A - L
B13 4.8/8.32 KV
BRIAN WILSON DS
10 MVA
BRIAN WILSON D.S
1434 INNISFIL BCH RD
F1- 225AMP A103 TYPE DV
F2- 250AMP ELECTRONIC LEXINGTON VAC. TYPE
F3- 250AMP ELECTRONIC JOSLYN VAC. TYPE
F4- 160AMP A103 TYPE DV
CEDAR POINT D.S
733 6TH LINE
4.8 / 8.32 KV
LEFROY D.S
1495 KILLARNEY BCH RD
9-280 A - L B13 4.8 / 8.32 KV
INNISFIL D.S
2255 HWY#89
4.8 / 8.32 KV
COMMERCE PARK DS
2033 COMMERCE PARK DR
F1 & F2 PADMOUNT 3PHASE VACCUM RECLOSERS
450 AMP MIN. TRIP PH TO PH.
350 AMP MIN. TRIP PH TO GRD.
CROSS PHASE OUT OF PHASE
WILL NOT PARALLEL
NOTE:
ONT HYDRO
SCALE
0 500 1000 2000 3000 4000 5000m
INNISFIL HYDRO
REG. PLANS
ORIENTATION
DRAWN
CHECKED
DATE 96.11.01
REV. 5
DATE NOV 07
BY R.R.
DWG. SCALE 1 : 24,000
DWG. NO. DP MAP 001 A



LEGEND

△ - POLE MOUNT TRANSFORMER
▲ - PADMOUNT TRANSFORMER
W - UNDERGROUND
○ - SWITCH

INNISFIL HYDRO

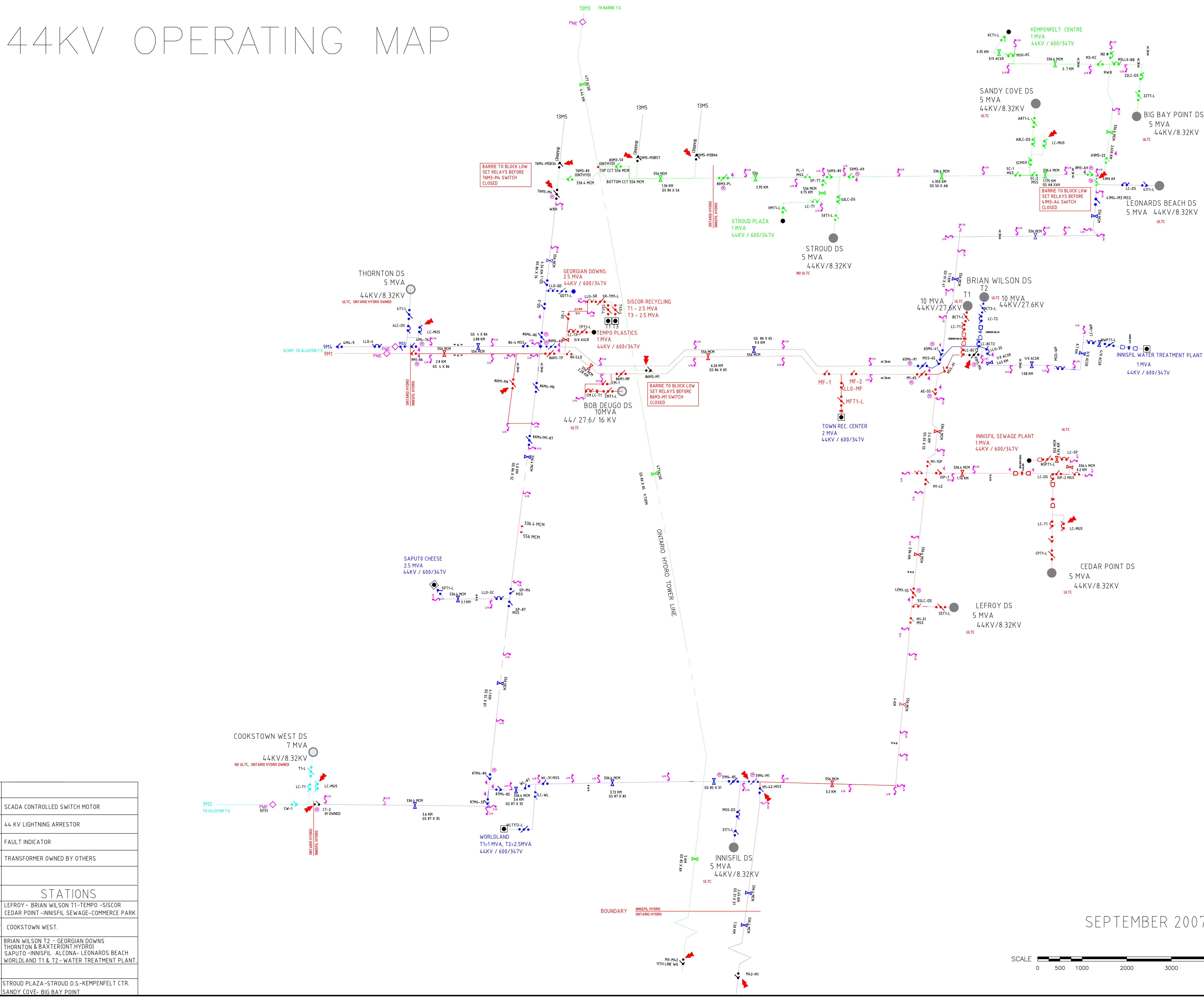
REG. PLANS	ORIENTATION

DRAWN	CHECKED	DATE
MM	.	23/04/08
REV.	DATE	BY
.	.	BY

DWG. SCALE
N.T.S

DWG. NAME:
44KV - TOWN OF INNISFIL

44KV OPERATING MAP



SEPTEMBER 2007

SCALE 0 500 1000 2000 3000 4000 5000m

LEGEND	
(M)	SCADA CONTROLLED SWITCH MOTOR
	44 KV LIGHTNING ARRESTOR
	FAULT INDICATOR
	TRANSFORMER OWNED BY OTHERS

FEEDERS	STATIONS
9M1 (IH)	LEFROY - BRIAN WILSON T1-TEMPO -SISCOR CEDAR POINT -INNISFIL SEWAGE-COMMERCE PARK
9M2 (OH)	COOKSTOWN WEST.
9M4 (IH)	BRIAN WILSON T2 - GEORGIAN DOWNS THORNTON & BAXTER(ONT.HYDRO) SAPUTO -INNISFIL ALCONA- LEONARDS BEACH WORLDLAND T1 & T2- WATER TREATMENT PLANT.
13M5(OH)	
13M3 (IH)	STROUD PLAZA-STROUD D.S.-KEMPENFELT CTR. SANDY COVE- BIG BAY POINT

FAULT INDICATORS 60 SEC. RESET

44 KV SWITCH LOCATIONS

FEEDER	SWITCH #	FIELD LOCATION
(M) TIE 9M1&9M4	31M4-M1	2nd POLE EAST OF 44KV TAP TO INNISFIL D.S ON HIGHWAY #89
(M) TIE 9M1 & 9M4	91M1-M4	3rd POLE EAST OF THE 44KV TAP TO BRIAN WILSON D.S. ON THE 8th LINE.
(O.H.) TIE 9M1 & 13M3	86M3-M1	1st POLE SOUTH OF H.V TOWER JUST NORTH OF THE 8th LINE.
(M) TIE 13M3&9M4	41M3-A9	1st POLE NORTH OF 44KV TAP TO LEONARDS BCH. D.S ON 25th SIDEROAD
TIE 13M3&9M4	76M3-80	SALEM ROAD EAST OF 5th SIDE RD
(M) TIE 9M4 & 13M3	76M3-M4	1st POLE SOUTH OF THE 1th LINE (SALEM ROAD),ON THE 5th SIDEROAD.
(M) TIE 9M2 & 9M4	CT-2	3rd POLE WEST OF DUFFERIN STREET ON VICTORIA STREET-WEST-COOKSTOWN
(BARRIE) TIE 13M5&9M4	76M4-M5B34	2nd POLE NORTH OF 11th LINE (SALEM RD.) ON THE 5th SIDEROAD
(M) 13M3	8M3-A9	2nd POLE WEST OF THE 25th SIDEROAD ON THE 11th LINE.
13M3	50M3-80	4th POLE EAST OF HIGHWAY #11 ON THE 11th LINE
13M3	A9M3-22	2nd POLE NORTH OF THE 11th LINE ON THE 25th SIDEROAD.
13M3	M3-KC	3rd POLE WEST OF THE 25th SIDEROAD ON THE 13th LINE
13M3	M3LLO-BB	13th LINE EAST OF 25th SIDEROAD.
13M3	PL-1	2nd POLE WEST OF HIGHWAY 11 ON THE 11th LINE
13M3	SC-1	WEST OF THE 44KV TAP POLE TO SANDY COVE D.S ON THE 11th LINE.
13M3	SP-77	HIGHWAY #11 SOUTH OF THE 11th LINE.
(M) 9M1	9M1-86	6 TH POLE EAST OF HIGHWAY 27 ON THE 8 TH LINE
(M) 9M1	LEM1-55	20 TH SIDE ROAD 2ND POLE NORTH OF 4 TH LINE
9M1	ISP-2MSS	EAST OF CEDAR POINT TAP
9M1	86M1-TP	2nd POLE EAST OF 5th SIDEROAD ON THE 8th LINE-EAST SIDE-D.A.B.S.
9M1	86-LLO	2nd POLE EAST OF INDUSTRIAL PARK ROAD ON THE 8th LINE.
(M) 9M1	AE-55	5th POLE SOUTH OF THE 8th LINE ON THE 20th SIDEROAD.
9M1	ISP-1	1st POLE EAST OF THE 20th SIDEROAD ON THE 6th LINE
9M1	M1-31	20TH SIDE ROAD SOUTH OF 4TH LINE
9M1	MSS-91	1st POLE EAST OF THE 20th SIDEROAD ON THE 8th LINE
9M1	M1-LE	20th SIDEROAD SOUTH OF THE 6th LINE.
(M) 9M1	M1-65	3rd POLE WEST OF THE 20th SIDEROAD ON THE 8th LINE D.A.B.S.
(M) 9M1	86M1-M6	2ND POLE SOUTH OF INNISFIL BEACH RD. ON THE EAST SIDE OF THE 5TH SR.
(M) 9M1	86M1-MF	INNISFIL BEACH RD EAST OF COMMERCE PARK DRIVE
9M4	MF-1, MF-2	INNISFIL BEACH RD EAST OF HIGHWAY #11 @ REC. CENTER
9M4	86M4/M1-87	7TH POLE SOUTH OF INISFIL BEACH RD. ON THE EAST SIDE OF THE 5TH SR.
9M4	MSS-65	8TH LINE 20TH SIDE ROAD
9M4	GD-2	1ST POLE SOUTH OF GEORGIAN DOWNS
9M4	GD-1	1ST POLE NORTH OF GEORGIAN DOWNS TAP ON THE 5TH S.R
(M) 9M4	31M4-85	3rd POLE WEST OF 44KV TAP TO INNISFIL D.S ON HIGHWAY #89
9M4	86M4-MSS	INNISFIL BEACH RD WEST OF 5TH SIDE RD.
(M) 9M4	4M4-76	5th POLE EAST OF HIGHWAY #27 ON THE 8th LINE.
(M) 9M4	50M3-A9	3rd POLE EAST OF 44KV TAP TO STROUD D.S ON THE 11th LINE
(M) 9M4	65M4-41	20th SIDEROAD NORTH OF THE 8th LINE.
(M) 9M4	65M4-91	3rd POLE WEST OF 20th SIDEROAD ON THE 8th LINE D.A.B.S.
(M) 9M4	86M4-65	2nd POLE EAST OF 5th SIDEROAD ON THE 8th LINE-WEST SIDE-D.A.B.S.
(M) 9M4	86M4-86	2nd POLE NORTH OF THE 8th LINE ON THE 5th SIDEROAD
(M) 9M4	86M4-M6	4TH POLE SOUTH OF INNISFIL BEACH RD. ON THE EAST SIDE OF THE 5th SIDEROAD
9M4	87M4-35	2nd POLE SOUTH OF HIGHWAY #89 ON THE 5th SIDEROAD.
9M4	87M4-85	1st POLE EAST OF THE 5th SIDEROAD ON HIGHWAY #89.
(M) 9M4	87M4-86	3rd POLE NORTH OF HIGHWAY #89 ON THE 5th SIDEROAD.
9M4	LLO-SC	4th LINE WEST OF THE 5th SIDEROAD.
9M4	SP-87	5th SIDEROAD SOUTH OF THE 4th LINE.
9M4	SP-M4	5th SIDEROAD NORTH OF THE 4th LINE.
9M4	WL-31	EAST OF WORLDLAND TAP HWY 89
9M4	M1-42	HWY 11 SOUTH OF HWY 89

INNISFIL HYDRO

REG. PLANS	ORIENTATION

DRAWN	CHECKED	DATE
		96.11.01
REV. 4.7	DATE SEPT 07	BY R.R.
DWG. SCALE	44KV OPERATING MAP	
DWG. NO.	44KVOM-001	

LIST OF NEIGHBOURING UTILITIES:

INNISFIL HYDRO neighbouring utilities are Barrie Hydro and Hydro One Systems.

BARRIE HYDRO	Direct line: 705-722-7244
55 Patterson Road	Direct Fax: 705-722-6159
Barrie, ON L4M 4V8	Website: www.barriehydro.com
HYDRO ONE NETWORKS INC.	Direct line: 416-345-5000
483 Bay St	Direct Fax: 416-345-5870
Toronto, ON M5G 2P5	Website: www.HydroOne.com

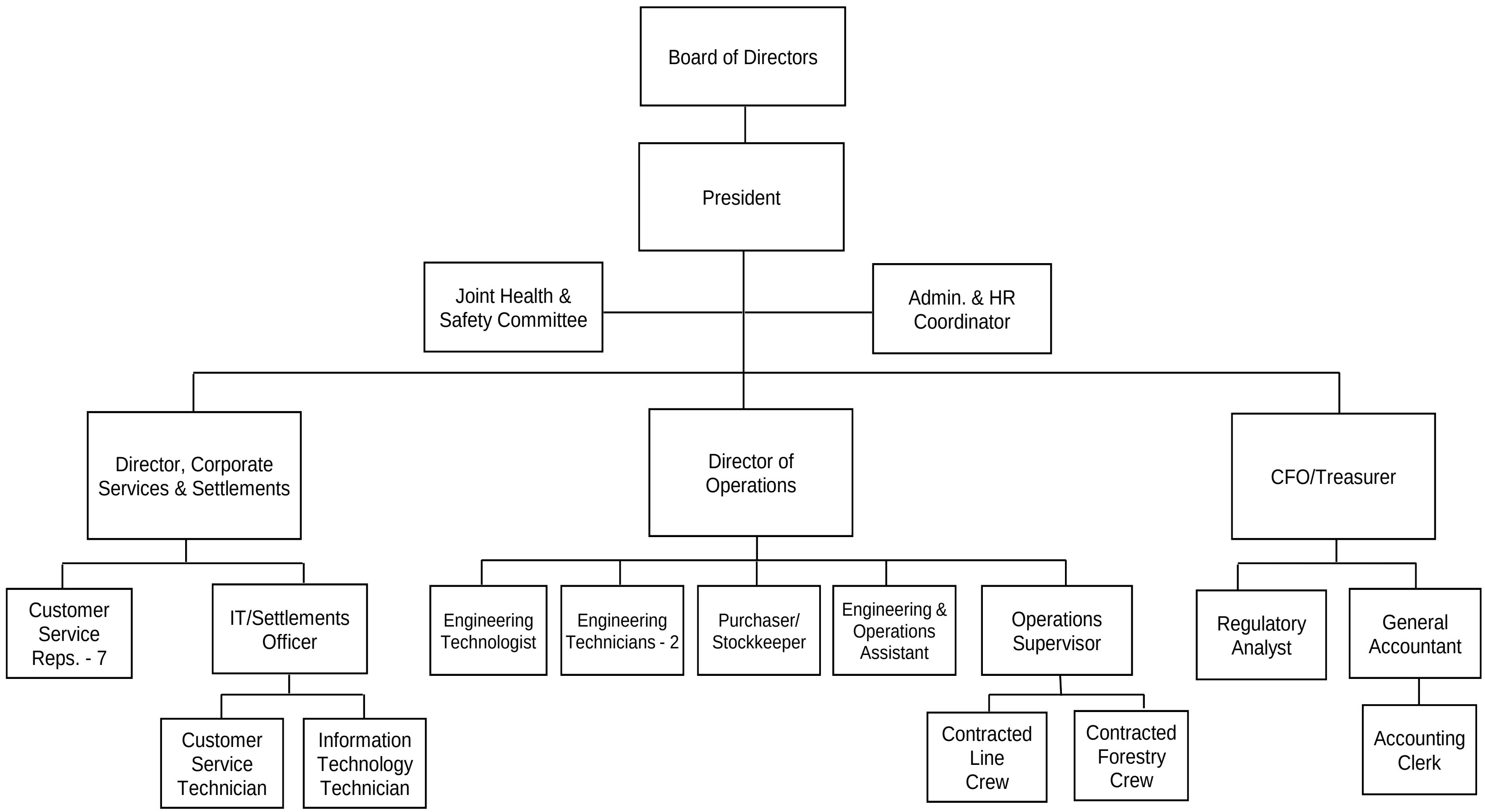
EXPLANATION OF HOST AND EMBEDDED UTILITIES:

Innisfil Hydro is an embedded distributor within Hydro One Networks territory.

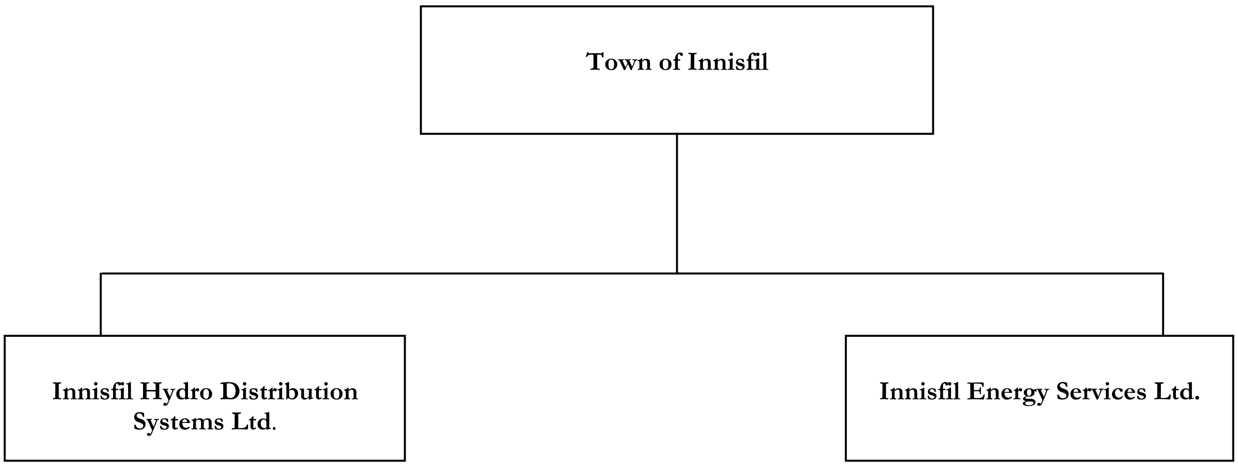
Innisfil Hydro does have an embedded utility, Hydro One, within its service area. The distributor is currently treated as a General Service >50 kW. This customer is essentially a meter serving customers in Hydro One territory. The OEB is currently reviewing the rate design for recovery of electricity distribution costs, EB-2007-0031. When the review findings are published, Innisfil Hydro will implement the requirements accordingly.

UTILITY ORGANIZATIONAL CHART:

INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED
ORGANIZATION CHART



CORPORATE ENTITIES RELATIONSHIPS CHART:



Innisfil Hydro Distribution Systems Limited

Innisfil Hydro is a wholly-owned corporation of the Town of Innisfil, and was incorporated October 5, 2000 under the laws of the Province of Ontario. The principal activity of the Company is to provide electrical power distribution throughout the Town of Innisfil.

Innisfil Energy Services Limited

Innisfil Energy Services Ltd. (IESL) is a wholly-owned corporation of the Town of Innisfil and was incorporated on October 5, 2000 under the laws of the Province of Ontario. The principal activities of the Company are to provide hot water tank and sentinel light rentals. Innisfil Hydro provides services under a Services Agreement to IESL, services which are estimated to cease in January 2009.

PLANNED CHANGES IN CORPORATE AND OPERATIONAL STRUCTURE:

No changes to Innisfil Hydro's corporate and operational structures are planned at the present time.

STATUS OF BOARD DIRECTIVES FROM PREVIOUS BOARD DECISIONS:

Innisfil Hydro Distribution Systems Ltd has no Board Directives at this time.

COMPANY POLICIES AND REGULATIONS/SERVICE CHARGES:

A copy of Innisfil Hydro's current Conditions of Service and Service charges has been provided as Appendix A to this application. The preparation of the COS was a joint effort of the CHEC group, one of the many initiatives that the group works collaboratively on to seek cost savings and other efficient synergies.

APPENDIX A

COPY OF INNISFIL HYDRO CONDITIONS OF SERVICE AND SERVICE CHARGES

CONDITIONS OF SERVICE

Table of Contents

SECTION 1 INTRODUCTION

1.1 Identification of Distributor and Territory

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

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

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

1.1.1 General

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

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

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

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

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

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

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

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

If special equipment is required or equipment delivery problems occur then longer lead times may be necessary. The customer will be notified of any extended lead times.

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

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

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

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

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

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

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

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

1.2 Related Codes and Governing Laws

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

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

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

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

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

1.3 Interpretations

In these Conditions, unless the context otherwise requires:

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

1.4 Amendments and Changes

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

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

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

1.5 Contact Information

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

1.6 Customer Rights

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

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

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

1.7 Distributor Rights

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

The Distributor shall have access to Customer property in accordance with section 40 of the *Electricity Act, 1998*.

1.8 Disputes

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

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

Mediation

- Either party (the "Initiating Party") may invoke the dispute resolution procedure by sending a written notice to the other party (the "Respondent Party") describing the nature of the dispute and designating a representative of the Initiating Party with appropriate authority to be its representative in negotiations relating to the dispute. The responding Party shall, within five business days of the receipt of such notice, send a written notice to the Initiating Party, designating a representative of the Responding party with the appropriate authority to be its representative in negotiations relating to the dispute.

- Within ten business days of the receipt by the Initiating Party of the written notice of the Responding Party the designated representatives shall enter into good faith negotiations with a view to resolving the dispute. If the dispute is not resolved in thirty days of the commencement of such negotiations, or such longer period as may be agreed upon, either party may, by written notice to the other party, require that the parties be assisted in their negotiations by the Ontario Energy Board. In accordance with the OEB dispute resolution process, The Ontario Energy Board will complete its review of the dispute within 150 days.

SECTION 2 DISTRIBUTION ACTIVITIES (GENERAL)

2.1 Connections

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

2.1.1 Building that Lies Along

As provided in Section 28 of the Electricity Act 1998 the Distributor has the Obligation to Connect any Building that 'lies along" its distribution system subject to conditions outlined in section 2.1.3.
A building 'lies along" a distribution line if it can be connected to the distributor distribution system without an expansion or enhancement.

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

2.1.2 Offer to Connect

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

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

2.1.3 Connection Denial

The Distribution System Code in section 3.1 sets 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

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

2.1.4 Inspections Before Connections

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

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

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

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

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

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

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

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

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

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

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

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

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

2.1.5 Relocation of Plant

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

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

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

2.1.6 Easements

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

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

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

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

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

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

2.1.7 Contracts

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

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

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

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

2.2 Disconnection

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

(a) contravention of the laws of Canada or the Province of Ontario including the Ontario Electrical Safety Code;

(b) violation of conditions in a distributor's licence;

(c) materially adverse effect on the reliability or safety of the distribution system;

(d) imposition of an unsafe worker situation beyond normal risks inherent in the operation of the distribution system;

(e) a material decrease in the efficiency of the distributor's distribution system;

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

2.3 Conveyance of Electricity

2.3.1 Guaranty of Supply

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

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

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

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

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

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

2.3.2 Power Quality

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

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

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

2.3.3 Electrical Disturbances

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

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

No electrical equipment, which may produce an undesirable system disturbance, shall be connected by a customer to a customer's service without prior approval of the Distributor.
Examples of equipment, which may cause disturbance, are large motors, welders and variable speed drives. In planning the installation of such equipment, the customer is required to consult with the Distributor.

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

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

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

2.3.4 Standard Voltage Offerings

2.3.4.1 For Secondary Voltage

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

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

OR

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

OR

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

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

2.3.4.2 For Primary Voltage

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

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

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

2.3.5 Voltage Guidelines

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

6% for Normal Operating Conditions
8% for Extreme Operating Conditions

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

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

2.3.6 Back-up Generators

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

To access the Code: http://www.esasafe.com/Corporate/gr_004.php?s=8
To review Generator Safety Info: http://www.esasafe.com/GeneralPublic/sgi_001.php?s=23

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

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

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

2.3.7 Metering

2.3.7.1 General

2.3.7.1.1 Access

The Distributor or its agents shall have the right to access and read any of the Distributors' electricity meters on the Customer's premises.

All metering installations shall be accessible from a public area.

2.3.7.1.2 Costs

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

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

2.3.7.1.3 Voltage

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

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

2.3.7.1.4 Primary Metering

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

2.3.7.1.5 Bulk Metering

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

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

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

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

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

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

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

2.3.7.1.6 Locks

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

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

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

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

2.3.7.1.7 Meter Seals

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

2.3.7.2 Current Transformer Boxes

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

As an alternative to a separate CT box and meter, a single enclosure combining both functions may be feasible. Contact the Distributor for details.

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

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

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

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

2.3.7.3 Interval Metering

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

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

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

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

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

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

2.3.7.3.1 Interval Metering Communications

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

2.3.7.3.2 Smart Meters

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

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

2.3.7.4 Meter Reading

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

2.3.7.5 Final Meter Reading

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

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

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

2.3.7.6 Faulty Registration of Meters

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

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

If the incorrect measurement is due to reasons other than the accuracy of the meter, such as incorrect meter connection, incorrect connection of auxiliary metering equipment, or incorrect meter multiplier used in the bill calculation, the billing correction will apply for the duration of the error. The Distributor will correct the bills for that period in accordance with the regulations under the Act.
http://www.collus.com/images/stories/Documents/Measurement Errors.pdf

2.3.7.7 Meter Dispute Testing

The Distributor will attempt to resolve billing enquiries. However, to give Customers confidence in the accuracy of electricity meters, the Distributor will conduct an internal investigation to verify the accuracy of any meter the Customer believes to be recording incorrectly. If the internal investigation does not resolve the matter, the Customer or the Distributor may request Measurement Canada to test the meter.
http://www.collus.com/images/stories/Documents/Measurement Errors.pdf

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

2.3.7.8 Location

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

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

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

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

2.3.7.9 Meter Mounting Heights

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

2.3.7.10 Environment

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

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

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

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

2.3.7.11 Meter Sockets

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

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

2.3.7.12 Cabinets

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

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

2.3.7.13 Metering Loops

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

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

2.3.7.14 Metal Enclosed Switchgear

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

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

- Colour coded secondary wiring
- Revenue meters

The Owner shall:

- Consult with The Distributor regarding the installation of metering equipment, which may include:

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

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

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

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

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

2.3.7.15 Switchgear Connected to Wye Source

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

2.3.7.16 Four Quadrant Metering (Generation)

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

2.3.7.17 Net Metering for Embedded Generation

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

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

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

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

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

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

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

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

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

b. for all other generators, an interval meter must be installed.

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

2.4 Tariffs and Charges

2.4.1 Service Connection

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

2.4.2 Energy Supply

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

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

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

2.4.4 Billing

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

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

2.4.4.1 Competitive Charges:

Are based on rates as determined by:

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

2.4.4.2 Non-competitive Charges:

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

2.4.4.3 Billable Engineering Units:

Customers will be billed on:

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

2.4.4.4 Use of Estimates:

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

2.4.5 Payments and Late Payment Charges

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

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

Where payment is made by mail, payment will be deemed to be made on the date post-marked. Where payment is made at a financial institution acceptable to the utility, payment will be deemed to be made when stamped/acknowledged by the financial institution or an equivalent transaction record is made.
A partial payment will be applied to any outstanding arrears before being applied to the current billing, unless special considerations have been made by the utility.

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

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

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

2.4.6 Unauthorized Energy Use

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

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

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

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

2.5 Customer Information

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

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

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

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

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

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

SECTION 3 CUSTOMER SPECIFIC

3.1 Residential

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

3.1.1 General

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

There shall be only one Delivery Point to a dwelling.

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

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

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

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

3.1.2 Early Consultation

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

3.1.3 Standard Connection Allowance

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

The basic connection for each customer shall include;

i. supply and installation of overhead distribution transformation capacity or an equivalent credit for transformation equipment; and

ii. up to 30 meters of overhead conductor or an equivalent credit for underground services.

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

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

3.1.4 Variable Connection Fees

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

3.1.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

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

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

3.1.5.1 Secondary Service Connections

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

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

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

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

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

3.1.5.2 Primary Service Connections

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

3.1.6 Supply Voltage

(a) A Residential building is supplied at one service voltage per land parcel.

(b) Depending upon the location of the building the supply voltage will be one of the following:

- *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 or bulk metering will be covered under section 3.2 of these Conditions of Service. Also 3.1.11.2

3.1.11.1 Service Information:

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

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

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

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

3.1.11.2 Metering:

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

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

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

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

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

3.1.12 Seasonal and Remote Dwellings:

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

3.1.12.1 Service Information:

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

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

3.1.12.2 Access:

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

- **Night crossings**

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

- **Ice conditions**

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

- **Severe weather conditions**

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

3.1.13 Inspection:

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

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

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

(Refer to section 2.1.4 for further inspection details)

3.2 General Service (Below 50 kW)

3.2.1 General

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

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

3.2.2 Early Consultation

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

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

3.2.3 Standard Connection Allowance

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

3.2.4 Variable Connection Fees

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

3.2.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

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

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

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

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

3.2.5.1 Secondary Service Demarcations

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

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

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

3.2.5.2 Primary Service Demarcations

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

3.2.6 Supply Voltage

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

(b) Depending upon the location of the building the supply voltage will be one of the following:

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

For more details refer to section 2.3.7 in these Conditions of Service.

3.2.9 Overhead Service:

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

3.2.10 Underground Service:

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

3.2.11 Supply of Equipment:

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

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

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

3.2.12 Inspection:

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

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

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

(Refer to section 2.1.4 for further inspection details)

3.3 General Service (Above 50 kW)

3.3.1 General

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

3.3.2 Early Consultation

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

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

3.3.3 Standard Connection Allowance

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

3.3.4 Variable Connection Fees

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

3.3.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

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

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

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

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

3.3.5.1 Secondary Service Connections

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

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

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

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

3.3.5.2 Primary Service Connections

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

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

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

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

In some instances primary metering may be required.

3.3.6 Supply Voltage

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

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

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

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

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

3.3.7 Access:

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

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

3.3.8 Metering:

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

For more details refer to section 2.3.7 in these Conditions of Service.

3.3.9 Overhead Service:

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

3.3.10 Underground Service:

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

3.3.11 Sub-transmission Service:

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

3.3.12 Supply of Equipment:

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

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

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

3.3.13 Short Circuit Capacity:

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

3.3.14 Inspection:

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

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

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

(Refer to section 2.1.4 for further inspection details)

3.4 General Service (Above 500 kW)

3.4.1 General

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

3.4.2 Early Consultation

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

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

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

The Distributor will:

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

3.4.3 Standard Connection Allowance

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

3.4.4 Variable Connection Fees

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

3.4.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

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

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

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

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

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

3.4.5.1 Service Installation

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3.5.2 Protection

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

3.5.2.1 Internal Faults:

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

3.5.2.2 External Faults:

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

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

3.5.2.3 Ground Faults:

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

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

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

3.5.2.4 Phase Faults:

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

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

3.5.2.5 Islanding/Abnormal Conditions:

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

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

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

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

3.5.3 Induction Generator

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

3.5.4 DC Remote Tripping / Transfer Tripping

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

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

3.5.5 Maintenance

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

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

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

3.6 Embedded Market Participant

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

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

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

3.7 Embedded Distributor

An Embedded Distributor shall provide the Distributor with proof of compliance of IESO and OEB registration Requirements, and appropriate Licences.

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

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

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

3.8 Miscellaneous Small Services

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

3.8.1 General

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

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

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

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

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

The Distributor at the Owners' expense will install required transformation.

Where at the discretion of the Distributor, a meter is not installed, energy consumption will based on the connected wattage and the calculated hours of use.

Prior to energization of a service the Distributor will require notification from the ESA that the installation has been inspected and approved for connection.

3.8.2 Early Consultation

The Owner shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment etc. Information required includes:

- Required in-service date
- Requested Service Entrance Capacity and voltage rating of the service entrance equipment
- Locations of other services, gas, telephone, water and cable TV
- Survey plan and site plan indicating the proposed location of the service equipment with respect to public rights-of way and lot lines.

3.8.3 Street Lighting

Town street-lighting that is designed, installed, and maintained by the Distributor shall be fully funded by the Municipality to ensure adherence to the Affiliate Relationship Code and the Distributors' Licence.

3.8.4 Traffic Signals

Traffic Signals and Crosswalk Lights are owned and maintained by the applicable road authority.

3.8.5 Bus Shelters

Bus Shelter Lighting is owned and maintained by the Customer.

3.8.6 Decorative Street Lighting

Such installations could be lighting for festive occasions or "neighbourhood character" street-scaping and will be maintained by the Customer.

SECTION 4 GLOSSARY OF TERMS

"Conditions of Service" means the document developed by the distributor in accordance with subsection 2.3 of the Distribution System Code, that describes the operating practices and connection rules for the distributor;

"Condominiums" are located on common land, which is the property of a condominium corporation or is owned by the Owner of all of the units (rental property). These units usually front onto internal roads that are also privately owned;

"Condominium Development" is a structure or complex of structures each containing more than two residential units. A single residential customer would occupy each unit and have direct outside access at ground level;

"Connection" means the process of installing and activating connection assets in order to distribute electricity;

"Connection Agreement" means an agreement entered into between a distributor and a person connected to its distribution system that delineates the conditions of the connection and delivery of electricity to or from that connection;

"Connection assets" means that portion of the distribution system used to connect a customer to the existing main distribution system, and consists of the assets between the point of connection on a distributors' main distribution system and the ownership Demarcation Point with that customer;

"Consumer" means a person who uses, for the person's own consumption, electricity that the person did not generate;

"Customer" means a person that has contracted for or intends to contract for connection of a building or an embedded generation facility. This includes developers of residential or commercial 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.

"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, 199*8, S.O. 1998, c.15, Schedule A;

***"*Energy Competition Act"** means the *Energy Competition Act, 199*8, S.O. 1998, c. 15;

"Electrical Safety Authority" or **"ESA"** means the person or body designated under the *Electricity Act* regulations as the Electrical Safety Authority;

"Embedded Distributor" means a distributor who is not a wholesale market participant and that is provided electricity by a host distributor;

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

"Embedded Load Displacement Generation Facility" means an embedded generation facility connected to the customer side of the revenue meter where the generation facility does not inject electricity into the distribution system for the purpose of sale;

"Embedded Market Participant" means a consumer who is a wholesale market participant whose facility is not directly connected to the IESO-controlled grid but is connected to a distribution system;

"Emergency" means any abnormal system condition that requires remedial action to prevent or limit loss of a distribution system or supply of electricity, or that could adversely affect the reliability of the electricity system;

"Emergency backup generation facility" means a generation facility that has a transfer switch that isolates it from a distribution system;

"Enhancement" means a modification to an existing distribution system that is made for purposes of improving system operating characteristics such as reliability or power quality or for relieving system capacity constraints resulting, for example, from general load growth;

"Expansion" means an addition to a distribution system in response to a request for additional customer connections that otherwise could not be made; for example, by increasing the length of the distribution system;

"Four-quadrant Interval Meter" means an interval meter that records power injected into a distribution system and the amount of electricity consumed by the customer;

"Generate", with respect to electricity, means to produce electricity or provide ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system;

"Generation Facility" means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system, and includes any structures, equipment or other things used for that purpose;

"Generator" means a person who owns or operates a generation facility;

"Geographic Distributor" with respect to a load transfer, means the distributor that is licensed to service a load transfer customer and is responsible for connecting and billing the load transfer customer;

"Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America;

"Holiday" means a Saturday, Sunday, statutory holiday, or any day as defined in the
Province of Ontario as a legal holiday;

"IESO" means the Independent Electricity System Operator established under the Electricity Act;

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

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

"Large Embedded Generation Facility" means an embedded generation facility with a name-plate rated capacity of 10MW or more;

"Lies Along" means a property can be connected to the distributor distribution system without an expansion or enhancement, and meets the conditions listed in the Conditions of Service of the distributor who owns or operates the distribution line.

"Load Transfer" means a network supply point of one distributor that is supplied through the distribution network of another distributor and where this supply point is not considered a wholesale supply or bulk sale point;

"Load Transfer Customer" means a customer that is provided distribution services through a load transfer;

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

"Medium Sized Embedded Generation Facility" means an embedded generation facility with a name-plate rated capacity of less than 10 MW and:

a) more than 500 kW in the case of a facility connected to a less than 15kV line;
b) more than 1 MW in the case of a facility connected to a 15 kV or greater line;

"Meter Service Provider" means any entity that performs metering services on behalf of a distributor, generator, or registered market participant;

"Meter Installation" means the meter and, if so equipped, the instrument transformers, wiring, test links, fuses, lamps, loss of potential alarms, meters, data recorders, telecommunication equipment and spin-off data facilities installed to measure power past a meter point, provide remote access to the metered data and monitor the condition of the installed equipment;

"Metering Services" means installation, testing, reading and maintenance of meters;

"Micro Embedded Load Displacement Generation Facility" means an embedded load displacement generation facility with a name-plate rated capacity of 10 kW or less;

"Net Metering" means a settlement process for Embedded Generation behind a Load Customer meter as defined by Ontario Regulation 541/05

"Ontario Electrical Safety Code" means the code adopted by O. Reg. 164/99 as the Electrical Safety Code;

"Ontario Energy Board Act" means the *Ontario Energy Board Act, 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 generation facility, means the connection point where electricity produced by the generation facility is injected into a distribution system;

"Rate" means any rate, charge or other consideration, and includes a penalty for late payment;

"Rate Handbook" means the document approved by the Board that outlines the regulatory mechanisms that will be applied in the setting of distributor rates;

"Regulations" means the regulations made under the *Act or the Electricity Act*;

"Retail", with respect to electricity means,

a) To sell or offer to sell electricity to a consumer
b) To act as agent or broker for a retailer with respect to the sale or offering for sale of electricity, or
c) To act or offer to act as an agent or broker for a consumer with respect to the sale or offering for sale of electricity.

"Retail Settlement Code" means the code approved by the Board and in effect at the relevant time, which, among other things, establishes a distributors' obligations and responsibilities associated with financial settlement among retailers and customers and provides for tracking and facilitating customer transfers among competitive retailers;

"Retailer" means a person who retails electricity;

"Service Area" with respect to a distributor, means the area in which the distributor is authorized by its license to distribute electricity;

"Small Embedded Generation Facility" means an embedded generation facility which is not a micro-embedded generation facility with a name-plate rated capacity of 500 kW or less in the case of a facility connected to a less than 15 kV line and 1MW or less in the case of a facility connected to a 15 kV or greater line;

"Smart Meter" means a device that measures electrical energy use (kilowatt-hours, kWh) on an hourly or sub-hourly basis and is part of an integrated data management system. The meter records, stores and transmits date and time-stamped meter readings to a utility's computer to facilitate Time-of-Use and Hourly billing. Smart meters may also include other capabilities and features to aid in load management and energy conservation.

"Standard Offer" means a settlement process for distribution connected Embedded Generation under contract for supply with the Ontario Power Authority.

"Total losses" means the sum of distribution losses and unaccounted for energy;

"Townhouses" are usually a free hold property, the land is owned by the individual Owners of each unit, fronting onto a municipal street;

"Townhouse Development" is a structure or complex of structures each containing more than two residential units. A single residential customer would occupy each unit, and have direct outside access at ground level;

"Transmission System" means a system for transmitting electricity, and includes any structures, equipment or other things used for that purpose;

"Transmission System Code" means the Board approved code that is in force at the relevant time, which regulates the financial and information obligations of the Transmitter with respect to its relationship with customers, as well as establishing the standards for connection of customers to, and expansion of a transmission system;

"Transmit" with respect to electricity, means to convey electricity at voltages of more than 50 kilovolts;

"Transmitter" means a person who owns or operates a transmission system;

"Unaccounted-for Energy" means all energy losses that cannot be attributed to distribution losses. These include measurement error, errors in estimates of distribution losses and un-metered loads, energy theft and non-attributable billing errors;

"Un-metered loads" means electricity consumption that is not metered and is billed based on estimated usage;

"Validating, Estimating and Editing (VEE)" means the process used to validate, estimate and edit raw metering data to produce final metering data or to replicate missing metering data for settlement purposes;

"Wholesale Market Participant" means a person that sells or purchases electricity or ancillary services through the IESO-administered markets;

SECTION 5 APPENDICIES

Contact Information

Local Distribution Company	Contact Phone Number	
Centre Wellington Hydro Ltd.		730 Gartshore Street, Box 217
Licence # ED-2002-0498	Phone: (519) 843-2900	Fergus, Ont. N1M 2W8
COLLUS Power Corp.		Box 189, 43 Stewart Road
Licence # ED-2002-0518	Phone: (705) 445-1800	Collingwood, Ont. L9Y 3Z5
Grand Valley Energy Inc.		P.O. Box 400 - 400 C Line
Licence # ED-2002-0512	Phone: (519) 928-3112	Orangeville, Ont. L9W 2Z7
Hydro 2000 Inc.		265 St. Philippe Street P.O.Box 370
Licence # ED-2002-0542	Phone: (613) 679-4093	Alfred, Ont. K0B 1A0
Innisfil Hydro Distribution Systems Limited.		2073 Commerce Park Drive
Licence # ED-2002-0520	Phone: (705) 431-4321	Innisfil, Ont. L9S 4A2
Lakefront Utilities Inc.		207 Division St. P.O. Box 577
Licence # ED-2002-0545	Phone: (905) 372-2193	Cobourg, Ont. K9A 4L3
Lakeland Power Distribution Ltd.		5-45 Cairns Cres.
Licence # ED-2002-0540	Phone: (705) 789-5442	Huntsville, Ont. P1H 2M2
Midland Power Utility Corporation		16984 Highway #12
Licence # ED-2002-0541	Phone: (705) 526-9361	Midland, Ont. L4R 4P4
Orangeville Hydro Ltd.		P.O. Box 400 - 400 C Line
Licence # ED-2002-0500	Phone: (519) 942-8000	Orangeville, Ont. L9W 2Z7
Orillia Power Distribution Corporation		360 West St. South, P.O. Box 398
Licence # ED-2002-0530	Phone: (705) 326-2495	Orillia, Ont. L3V 6J9
Parry Sound Power Corporation		125 William Street
Licence # ED-2003-0006	Phone: (705) 746-5866	Parry Sound, Ont. P2A 1V9
Rideau St. Lawrence Distribution Inc.		985 Industrial Rd. P.O. Box 699
Licence # ED-2003-0003	Phone: (613) 925-3851	Prescott, Ont. K0E 1T0
Wasaga Distribution Inc.		950 River Road West P.O. Box 20
Licence # ED-2002-0544	Phone: (705) 429-2517	Wasaga Beach, Ont. L0L 2P0
Wellington North Power Inc.		290 Queen Street West, P.O. Box 359
Licence # ED-2002-0511	Phone: (519) 323-1710	Mount Forest, Ont. N0G 2L0
Westario Power Inc.	Phone: (519) 507-6937	24 Eastridge Road R.R. #2
Licence # ED-2002-0515	Toll Free: 1-866-978-2746	Walkerton, Ont. N0G 2V0
West Coast Huron Energy Inc.		64 West Street
Licence # ED-2002-0510	Phone: (519) 524-7371	Goderich, Ont. N7A 2K4
Woodstock Hydro Services Inc.		16 Graham Street P.O. Box 1598
Licence # ED-2003-0011	Phone: (519) 537-3488	Woodstock, Ont. N4S 0A8

Note: Licence Numbers published by OEB as of May 8, 2008

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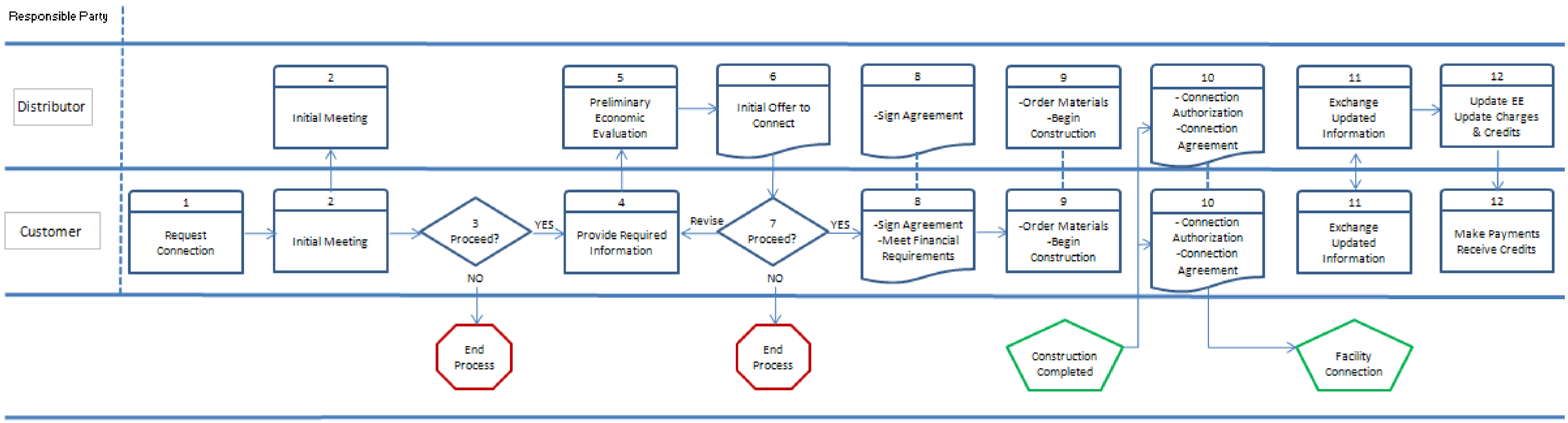
Distribution Connection

Distribution Connection
Developments & General Service Customers



Distribution Connection
Developments & General Service Customers

If you are planning on building a Subdivision, Commercial Building, or an Industrial Development, the process of connecting to the Local Distribution Infrastructure will require coordination with the Distributor.

The following information in conjunction with the preceding chart is designed to assist the parties in meeting their respective obligations and facilitate the required connection. It is important to note although the steps identified in both the chart and the following descriptions need to be followed in proper order, some of the steps may be combined to help speed up the process if all the required information is provided in a timely manner.

Step 1 – Request for Connection

Customer submits a connection request to the Distributor. Initial request should at a minimum include the following information:

- Location of proposed development
- General description of development
- Proposed construction date
- Contact information for Development

Step 2 – Initial Meeting

Customer and Distributor meet to review proposed new development and connection requirements. Initial meeting will provide both parties with an opportunity to gain a better understanding of the proposed development and identify any issues related to timing and connection to the Distribution System.

Based on the information provided by the customer prior to the meeting, the Distributor will be able to provide at a high level:

- An initial concept of the type of work that may be required to facilitate a connection. ie:
    - Extension of an existing Feeder
    - Potential requirement for a new DS
    - Add a second or third phase to an existing feeder
- An understanding of the of the customer responsibilities
- An understanding of what must be managed by the Distributor
- An understanding of what may be contracted by the customer
- An estimated timeline required to provide connection facilities
- An initial estimate of required enhancement or expansion costs – note: more detailed estimates on costs will be provided with the Offer to Connect should the Customer choose to continue to Step 4.

Step 3 – Customer Decision
Based on the results of the initial meeting, the Customer decides on proceeding with the process or withdrawing their Request for Connection.

Step 4 – Customer Provides Required Information

If the Customer decides to proceed with the process for acquiring a connection, the Customer notifies the Distributor and provides the relevant detailed information as noted below:

- A statement noting if the Customer intends on managing the contestable work noted during the consultation
- Number of Residential Connections
- Residential – Type, Number, and size of units
- Number of Commercial / Industrial Connections
- Estimated Average Monthly consumption (at minimum winter & summer estimates)
- Estimated annual facility connections over five years from date of LDC system connection

The following information is also required however the Distributor reserves the right to perform the work internally or through an external consultant:

- Design and engineering specifications including but not limited to stamped site service drawings
- Determination of required Transformation based on estimated building loads
- Estimated Capital costs of facilities which would be assumed by the Distributor following energization

To assist the Customer in providing the required information, a submission summary sheet is provided as an attachment to this document.

Step 5 – Preliminary Economic Evaluation

Upon receipt of the required information from the Customer, if an expansion of the distribution system is required, the Distributor will perform a preliminary Economic Evaluation following the process as required in the Distribution System Code.

The Preliminary Economic Evaluation will assist the Distributor in calculating what (if any) portion of the Capital Costs the LDC will invest and will be used in the preparation of the Offer to Connect.

Step 6 – Offer to Connect

Using the information provided by the Customer, and following the completion of the Preliminary Economic Evaluation, the Distributor will prepare an “Offer to Connect”. The Offer to Connect will contain the following information:

- A statement as to whether the offer is a firm offer or an estimate to be revised after the actual costs are known
- The amount of Capital Contribution that will be required from the Customer
- The amount of the Expansion Deposit that will be required from the Customer
- A description of the costs related to the Capital Contribution
- The costs for inspections
- A description of the deliverables required from the Customer before Connection
- An estimated Connection Date

Step 7 – Customer Decision

Customer Reviews Offer to Connect and decides if they would like to continue with the project as planned. Three options are available to the Customer:

- Customer elects to drop the project a notice of withdrawal of the Request for Connection shall be provided to the Distributor.
- Customer would like to revise their Connection request, a notice informing the Distributor of the requested changes shall be provided to the Distributor (go back to Step 4)
- Customer agrees with the Offer to Connect,

Step 8 – Construction Agreement
Once the Customer accepts the Distributor's Offer to Connect, the parties shall enter into an agreement covering the construction and connection requirements and responsibilities.
The Customer and the Distributor sign the agreement and the Customer provides the financial deposits and/or guarantees as required.

Step 9 – Construction
Following receipt of signed Construction Agreement and required financial deposits and/or guarantees from the Customer, both parties shall begin ordering materials and begin construction.

Step 10 – Connection Authorization
Once construction is completed, both parties will ensure that inspections are completed and all required connection authorizations are in place. After receipt of a signed connection agreement and any additional financial contributions, the Distributor will authorize and connect the facility. If the customer is coordinating the work on the expansion facilities within the development, the customer is also required to provide "As-Built" drawings and a detailed material listing to ensure the Distributor has sufficient information in hand to verify system security prior to energization.

Step 11 – Exchange Updated Information
The Customer and the Distributor shall exchange any required updated information on the project including, but not limited to:
- All applicable Connection Authorizations
- All applicable Warranties
- Any new information that was provided as an estimate in Step 4
- Actual costs of any "capital works" related to the expansion facilities within the development
- Detailed site plan with appropriate Municipal Address information for individual services

Step 12 –Updated Economic Evaluation
As required, the Distributor shall recalculate the Preliminary Economic Evaluation using actual information acquired during and following the construction process.

If the development includes estimated connections that are not energized at the time of the initial Connection, the Distributor shall re-run the Economic Evaluation on an annual basis using actual customer connection information during the five (5) year connection horizon used in the initial Economic Evaluation.

Request for Connection

Development Name:	
Site Plan Identification	

Contact Information:

Contact Name:	
Street:	
Town:	
Postal Code:	

Requested Connection Date:	

Multi-Phase Development?	Y / N
If YES - Identify Phase	

<u>Type & Number of Connections:</u>

		Average Monthly Consumption Per Unit - Winter	Per Unit - Summer
Residential:		Kwh's	Kwh's
Commercial:		Kwh's	Kwh's
Industrial:		Kwh's	Kwh's

Residential Dwelling Design:	Town Homes	
	Semi-Detached	
	< 1,500 SqFt Single Dwellings	
	>1,500 <3,500 SqFt Single Dwellings	
	> 3,500 SqFt Single Dwellings	

Connection Horizon

Year 1		
Year 2	Estimated connections in 1st year	
Year 3	Estimated connections in 2nd year	
Year 4	Estimated connections in 3rd year	
Year 5	Estimated connections in 4th year	
	Estimated connections in 5th year	

Capital Costs:

Distribution Infrastructure:	
Transformers:	
Ducts & Structures:	

Date: Submitted:	
Submitted By:	
Signature:	

Electrical Planning Requirements

It is essential that the following information be provided to:

a) enable an assessment to be made on the impact of the proposed project on the Electrical Distribution System.

b) enable the Distributor to prepare pertinent information for the developer.

Please supply answers to the following questions as soon as possible as electrical planning cannot proceed until the Distributor has reviewed this information.

Preliminary electrical site plan drawings are to be submitted together with this form. Electrical drawings are to be submitted to the Distributor for approval prior to any related job tenders or the commencement of any electrical construction. The drawings shall be drawn to a scale usable by the Distributor, shall show local pole locations, proposed transformer location, proposed electrical room/metering location and show how access to the metering would be gained (i.e.: the path to the metering).

Electrical site plan drawings are to be submitted to the Distributor on one (1) Paper copy and in an electronic format as approved by the Distributor.

Project Location: **(Municipal Address)** ______________________

Name of Project: ______________________

Name of Applicant: ______________________

Address: ______________________

Contact Name: ______________________

Address: ______________________

E-Mail: ______________________

Telephone: ( ) ______________________ **Fax:** ( ) ______________________

Service Classification (☒ as many as apply):

☐ Residential

☐ General Service < 50kW

☐ General Service > 50kW

☐ General Service >500kW

☐ Unmetered os Miscellaneous Load

☐ Temporary Service

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

What service voltage is required (☒ one only):

☐ 120/240 Volt Single Phase

☐ 120/208 Volt Three Phase

☐ 347/600 Volt Three Phase

☐ Primary

Metering Type (☒ one only):

☐ Single Meter

☐ Multiple Meters

Quantity of Meter installations

100A or less: _________

101A to 200A: _________

more than 200A: _________

Required In-Service Date:

Month / Day / Year ______/_______/_________

Comments: **Please use the back of this form for comments**

Signed: ______________________ **Date:** ______________________

(Representative of Applicant)

Name: ______________________ **Title:** ______________________

____

Electric Service Meter Base With Municipal Address Verification Form

LOCAL DISTRIBUTION COMPANY NAME: ______________________ **(UTILITY)**

This form **must** be completed by a Licensed Electrical Contractor or their legal representative prior to service connection. Accurate information must be provided or service will not be activated. ***(Sections A & B must be fully completed.)***

Electric Service Municipal Address: (Print) ______________________
Name of Owner: ______________________
Telephone: (______) ______________ Fax: (______)______________
Name of Electrical Contractor: ______________________
Telephone: (______) ______________ Fax: (______)______________

In area (A) provided below, a 'front-view' layout of the Electric Meter Base(s) is shown including an assigned number for each base. Provide Municipal Address (B) information for each corresponding meter base number for billing purposes.

(A) FRONT VIEW OF ELECTRIC METER BASE(S)	(B) MUNICIPAL ADDRESS (Print)
	1)
	2)
	3)
	4)
	5)
	6)
	7)
	8)

The following regulations are agreed upon by the undersigned with receipt of the completed form by an authorized representative of the Utility: *(A copy of the utility authorized form will be provided for your records.)*

1. That all information contained on this form is accurate.
2. That if any information is determined to be inaccurate, the Utility will not be able to energize the service connection(s).
3. That if any information has to be corrected by Utility personnel there will be applicable charges to prepare an amended form.
4. That an amended form must be signed and returned along with payment of any applicable invoice, as per Part 3, prior to further consideration as to the activation of the service connection.
5. **The Electrical Contractor completes Section (C) below to apply for service activation. A property owner MAY complete Section (D) rather than the contractor, to apply for service activation.**

(C) The undersigned acknowledges agreement to all terms and conditions contained on this form.
(Please print names in full)

Company Name: ______________________

Representative: ______________________

Title/Position: ______________________ Date: ____ (m / d / y)

Signature ______________________

(D) OPTIONAL if section (C) has been completed. The undersigned acknowledges agreement to all terms and conditions contained on this form.

Owner Name: *(Please print)* ______________________

Signature: ______________________ Date: ____ (m / d / y)

For COLLUS Power office use only:

Received : ______________________ Date __/__/__ Approved: ______________________
(Authorized Rep's Name) (m / d / y) (Rep's Signature)

______________________ ______________________
(Address) (Telephone #)

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PLANNED CHANGES IN CONDITIONS OF SERVICE:

Innisfil Hydro's Conditions of Service were filed with the Board in August 2008. Since that time there have been no changes.

PRELIMINARY LIST OF WITNESSES:

To be provided when further details on the oral component of the review process is known.

BUDGET DIRECTIVES:

Innisfil Hydro compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budget forecast. This budget information is compiled for both the 2008 Bridge Year and the 2009 Test Year.

Revenue Forecast

Innisfil Hydro's energy sales and revenue forecast model was updated to reflect recent information. This model was then used to prepare the revenues sales and 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, load profiles for all classes of customers and historical conservation and demand management initiatives through the third tranche CDM funding and the programs developed through the Ontario Power Authority.

Operating Maintenance and Administration ("OM&A") Expense Forecast

The OM&A expenses for the 2008 Bridge Year and the 2009 Test Year have been based on an in-depth review of operating priorities and requirements and is strongly influenced by prior year experience. All unavoidable increases and unmet needs from the prior budget period are identified and reviewed in detail. Each item is reviewed account by account for each of the forecast years with indirect costs allocated to direct costs for budget presentation.

Capital Budget

The capital budget forecast is prepared for a 1 and 5 year period. Capital projects are influenced by Innisfil Hydro's capacity to finance capital projects and the asset management plan guidelines. Indirect costs are allocated to direct costs in the capital budget. All proposed capital projects are assessed within the framework of its capital budget priority-setting criteria. Those criteria are discussed in greater detail in Exhibit 2 Tab 3 Schedule 1 (Capital Budget by Project).

CHANGES IN METHODOLOGY:

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

CALCULATION OF REVENUE DEFICIENCY
2009 TEST YEAR

	2009 Test Existing Rates	2009 Test Proposed Rates
Revenue		
Suff/ Def From Below.		$1,071,765
Distribution Revenue	$6,678,669	$6,678,669
Other Operating Revenue (Net)	$491,257	$491,257
Total Revenue	$7,169,926	$8,241,691
Distribution Costs		
Operation, Maintenance, and Administration	$3,921,120	$3,921,120
Depreciation & Amortization	$1,980,834	$1,980,834
Property & Capital Taxes	$31,051	$31,051
Interest- Deemed Interest	$838,240	$838,240
Total Costs and Expenses	$6,771,245	$6,771,245
Utility Income Before Income Taxes	$398,681	$1,470,445
Net Adjustments per 2008 Pils	$274,753	$274,753
Taxable Income	$673,434	$1,745,198
Income Tax (Tax Rate 33.0%)	$222,233	$575,915
Utility Income	$176,448	$894,530
Rate Base	$24,089,366	$24,089,366
Equity	43.33%	43.33%
Equity Component Rate Base	$10,437,922	$10,437,922
Income / Equity Rate Base %	1.69%	8.57%
Target Return -Equity on Rate Base	8.57%	8.57%
Return- Equity on Rate Base	$894,530	$894,530
Revenue Deficiency	$718,082	
Revenue Deficiency (Gross-up)	$1,071,765	

CAUSES OF REVENUE DEFICIENCY:

Innisfil Hydro's net revenue deficiency is calculated as $718,082 and when grossed up for PILs, the revenue deficiency is $1,071,765. Innisfil Hydro's calculation of its 2009 revenue deficiency is provided in Exhibit 1, Tab 2, Schedule 3 and Exhibit 7, Tab 1, Schedule 1.

The revenue deficiency is primarily the result of:

- Projected increases in OM&A costs including depreciation expense for the 2009 Test Year from the 2006 EDR application relating to issues such as inflation, contracted line crew services and staffing. Further detail is outlined in Exhibit 4, Tab 1, Schedule 1 and Tab 2, Schedule 2; and

- Projected increases in investments in gross assets due to expansions and aging infrastructure replacement. This results in an increase in the 2009 rate base on which the rate of return is based as discussed further in Exhibit 2, Tab 1 (Rate Base) and Tab 2 (Gross Assets – Property, Plant and Equipment).

FINANCIAL STATEMENTS – 2006 and 2007:

The Innisfil Hydro Audited 2006 and 2007 Financial Statements accompany this Schedule as Appendix A.

APPENDIX A

COPY OF AUDITED FINANCIAL STATEMENTS FOR 2006 AND 2007

Innisfil Hydro Distribution Systems Limited
Financial Statements
December 31, 2006

Grant Thornton

INNISFIL HYDRO
DISTRIBUTION SYSTEMS LIMITED

Contents

Grant Thornton LLP
Chartered Accountants
Management Consultants
Canadian Member of
Grant Thornton International

Grant Thornton

Auditors' Report

To the Directors of
Innisfil Hydro Distribution Systems Limited

We have audited the balance sheet of Innisfil Hydro Distribution Systems Limited 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 cash flows for year then ended in accordance with Canadian generally accepted accounting principles.

Grant Thornton LLP

Chartered Accountants

Barrie, Canada
March 1, 2007

Suite 201
85 Bayfield Street
Barrie, Ontario
L4M 3A7
Tel: (705) 730-6574
Fax: (705) 730-6575
E-mail: Barrie@GrantThornton.ca

Innisfil Hydro Distribution Systems Limited
Statements of Earnings and Retained Earnings

Year Ended December 31	2006	2005
Revenue		
Sale of power	$ 16,807,414	$ 17,757,193
Distribution	6,842,889	5,508,051
	23,650,303	23,265,244
Cost of power		
Power purchased	16,807,414	17,757,193
Gross margin	6,842,889	5,508,051
Other revenue (Note 13)	607,413	507,942
Expenses		
Distribution	1,017,296	1,017,608
Billing and collecting	829,594	842,374
Administration	1,101,657	902,825
Amortization	1,550,134	1,485,975
	4,498,681	4,248,782
Earnings from operations	2,951,621	1,767,211
Interest on long term debt	839,794	895,610
Earnings before payments in lieu of taxes	2,111,827	871,601
Payments in lieu of taxes (Note 11)	1,045,000	159,000
Net earnings	$ 1,066,827	$ 712,601

Retained earnings, beginning of year	$ 1,143,873	$ 759,273
Net earnings	1,066,827	712,601
Dividends	(542,000)	(328,000)
Retained earnings, end of year	$ 1,668,700	$ 1,143,874

See accompanying notes to the financial statements.

Innisfil Hydro Distribution Systems Limited
Balance Sheet

December 31		2006		2005
Assets				
Current				
Cash	$	2,090,951	$	3,181,663
Receivables		2,049,672		952,735
Due from related party (Note 3)		39,690		89,599
Notes due from related party (Note 3)		996,000		996,000
Unbilled revenue		2,633,137		2,751,169
Inventory		262,724		220,213
Income taxes recoverable		-		343,910
Prepaids		176,333		171,952
		8,248,507		8,707,241
Restricted cash - development charges (Note 5)		-		511,369
Property and equipment (Note 4)		17,251,653		16,293,843
Regulatory assets (Notes 6)		1,279,041		1,903,637
	$	26,779,201	$	27,416,090
Liabilities				
Current				
Bank indebtedness (Note 7)	$	-	$	1,000,000
Payables and accruals		2,875,584		1,962,462
Customer credit balances and deposits		483,192		846,016
Income taxes payable		374,614		-
Due to related party (Note 3)		161,850		172,575
Current portion of long-term debt		2,592,444		440,000
		6,487,684		4,421,053
Customer and retailer deposits		438,286		239,808
Development charges (Note 5)		-		511,368
Regulatory liabilities (Note 6)		621,466		1,186,801
Long term debt (Note 8)		6,155,000		8,747,444
		13,702,436		15,106,474
Shareholder's Equity				
Capital stock (Note 9)		10,852,444		10,852,444
Development charges transferred to equity (Note 5)		555,621		313,298
Retained earnings		1,668,700		1,143,874
		13,076,765		12,309,616
	$	26,779,201	$	27,416,090

Contingent liabilities (Note 12)

On Behalf of the Board

_____________ Director Robert S. Palee _____________ Director

See accompanying notes to the financial statements.

Innisfil Hydro Distribution Systems Limited
Statement of Cash Flows

Year Ended December 31	2006	2005
Increase (decrease) in cash and cash equivalents		
Operating		
Net earnings	$ 1,066,827	$ 712,601
Amortization	1,550,134	1,485,975
	2,616,961	2,198,576
Customers and retailer deposits	198,478	37,639
Change in non-cash operating working capital (Note 17)	282,209	(887,191)
	3,097,648	1,349,024
Financing		
Banker acceptance advances	(1,000,000)	-
Capital contributions	1,020,015	248,035
Dividends	(542,000)	(328,000)
Decrease in long term debt	(440,000)	(399,000)
Equity development charges	242,323	-
	(719,662)	(478,965)
Investing		
Net additions to property and equipment	(3,527,959)	(1,298,789)
Net (reduction) additions to regulatory liabilities	(565,335)	425,819
Net reduction to regulatory assets	624,596	1,197,336
	(3,468,698)	324,366
Net (decrease) increase in cash	(1,090,712)	1,194,425
Cash, beginning of year	3,181,663	1,987,238
Cash, end of year	$ 2,090,951	$ 3,181,663

See accompanying notes to the financial statements.

1. Nature of operations

The company distributes electricity under license from the Ontario Energy Board (OEB). The Electricity Act, 1998 provides for a competitive marketplace in the sale of electricity. The Ontario Energy Board Act, 1998 (Ontario) (OEBA) conferred on the Ontario Energy Board (OEB) increased powers and responsibilities to regulate the electricity industry. These powers and responsibilities include the power to approve or fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity consumers, and the responsibility for ensuring that distribution companies fulfil obligations to connect and service customers. The OEB may also prescribe license requirements and conditions to electricity distributors, which may include among other things, specified accounting records, regulatory accounting principles, separation of accounts for distinct businesses and filing and process requirements for rate setting purposes.

2. Summary of significant accounting policies

Cash and cash equivalents

Cash and cash equivalents include cash, short term investments and bank balances.

Revenue recognition

Sale of power, distribution and related revenues are based on OEB approved unbundled rates and are recognized as power is delivered to customers. The company estimates the monthly revenue for the period based on customer's usage because customer meters are not generally read at the end of each month. Unbilled revenue is recognized for customer usage not billed at December 31, 2006.

Other revenue is recognized as services are rendered.

Inventory

Inventory consists of repair parts, supplies and materials held for future capital expansion and is valued at lower of average cost and estimated net realizable value.

Rate-setting

The electricity distribution business is subject to rate regulation by the OEB. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. This change in timing gives rise to the recognition of regulatory assets and liabilities. These regulatory assets and liabilities reflect the fact that revenue and expenses are recognized in the financial statements in different periods consistent with their inclusion in rates, as directed by the regulator, than would be the case for an enterprise that is unregulated. Specific regulatory assets and liabilities recognized at December 31, 2006 are disclosed in Notes 6.

2. Summary of significant accounting policies (Continued)

Rate-setting (Continued)

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

Amortization

Property and equipment are amortized using the straight-line method over periods approximating their estimated useful lives as follows:

Land rights	50 years
Buildings	25 years
Distribution system	25 years
System supervisory equipment	15 years
Other equipment	5-10 years
Computer equipment	5 years
Computer software	3 years
Contributions in aid of construction	25 years

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

Fixed assets retirement obligations

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

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

2. Summary of significant accounting policies (Continued)

Corporate income and capital taxes

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

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

Use of estimates

In preparing the company's financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenue and expenditures during the year. Actual results could differ from these estimates.

3. Related party transactions

The company had the following related party transactions:

	2006	2005
Innisfil Energy Services Limited ("IESL") - affiliated company controlled by shareholder		
Services provided	$ **51,396**	$ 46,914
Interest on advances	**55,012**	41,621
The Corporation of The Town of Innisfil ("Town") - shareholder		
Interest on advances	**810,915**	852,566
Electrical services billed	**1,090,765**	922,532
Professional services billed	**65,149**	72,452
Dividends paid	**542,000**	328,000
Municipal taxes	**48,638**	39,612
Other expenses	**110,536**	41,840

3. Related party transactions (Continued)	**2006**	2005
Balances outstanding at December 31:		
Due from Innisfil Energy Services Limited	$ **39,690**	$ 89,599
Notes due from Innisfil Energy Services Limited	**996,000**	996,000
Dividend payable included in payables and accrued liabilities	**117,000**	-
Note and debenture payable to Town	$ **8,747,444**	$ 9,187,444
Accrued interest, due to Town	**161,850**	172,575
Due from Town, included in receivables	**88,681**	30,143

The note due from IESL is secured by a General Security Agreement conveying first fixed and floating charges over the property, assets, rights and interests of IESL, is repayable upon demand, and bears interest at the prime rate of a Canadian chartered bank less 0.25% per annum, payable monthly. The note and interest thereon have been recorded in these financial statements at the carrying amounts, which were equal to historical cost or fair value. The interest rate represents fair value as advised by the company's bankers.

During the year, the company provided financial, management and accounting services to IESL in the amount of $51,396 (2005 - $46,914). These transactions have been recorded in these financial statements at the carrying amounts, which were equal to historical cost or fair value. Fair value represents fees for equivalent services provided to third parties in the normal course of operations as prescribed by regulation. At the end of the year, $39,690 (2005 - $89,599) was due from IESL.

The company provides electricity and services to the Town. These transactions are in the normal course of operations and are measured at the exchange amount, which is equal to fair value as prescribed by regulation. During the year, the company billed electricity and services to the Town in the amount of $1,090,765 (2005 - $922,532) and professional services in the amount of $65,149 (2005 - $72,452). At the end of the year, $88,681 (2005 - $30,143) was due for these services. During the year, the company paid municipal taxes of $48,638 (2005 - $39,612) and other expenses of $110,536 (2005 - $41,840) to the Town.

4. Property and equipment

	Cost	Accumulated Amortization	2006 Net Book Value	2005 Net Book Value
Land	$ 484,399	$ -	$ **484,399**	$ 484,399
Land rights	952,186	475,838	**476,348**	494,755
Building and fixtures	564,326	138,162	**426,164**	397,700
Distribution station equipment	4,230,859	1,851,898	**2,378,961**	1,070,738
Distribution system	33,496,042	17,944,161	**15,551,881**	14,990,334
System supervisory equipment	1,058,231	387,639	**670,592**	734,695
Other equipment	698,871	510,201	**188,670**	181,993
Computer hardware	599,950	482,976	**116,974**	89,441
Computer software	600,935	481,468	**119,467**	118,067
Contributions in aid of construction	(3,672,237)	(510,434)	**(3,161,803)**	(2,268,279)
	$ 39,013,562	$ 21,761,909	$ **17,251,653**	$ 16,293,843

5. Development charges transferred to equity

In accordance with the Electricity Act, 1998, the development charges collected prior to January 1, 2000 and expended on qualifying growth-related capital assets are to be transferred to equity. Accordingly the company has transferred $555,621 to equity including $242,323 in the current year.

6. Regulatory assets and liabilities

Regulatory assets and liabilities arise as a result of the rate-making process. Innisfil Hydro has recorded the following regulatory assets and liabilities (Note 2)

	2006	2005
Regulatory assets		
Regulatory asset recovery account I and II	$ **1,132,273**	$ 1,781,460
Other	**146,768**	122,177
Total regulatory assets	$ **1,279,041**	$ 1,903,637
Regulatory liabilities		
Other	$ **347,608**	$ 425,819
Retail settlement variance accounts	**273,858**	-
Premarket opening energy variance	**-**	760,982
Total regulatory liabilities	$ **621,466**	$ 1,186,801

6. Regulatory assets and liabilities (Continued)

Regulatory assets

Regulatory asset recovery account I and II (RARA I and RARA II)

On December 9, 2004, the OEB issued a decision on the prudence of the distribution-related deferral account balances for which recovery was sought by Innisfil Hydro in its May 31, 2004 application. Amounts for which recovery was approved represented balances incurred prior to December 31, 2003, plus associated interest. The OEB ordered that the approved amounts be aggregated into a single regulatory account to be recovered on a straight-line basis over the period ending April 30, 2008. The RARA I includes distribution business low-voltage services amounts, deferred market ready expenditures, retail settlement variance amounts, and other amounts primarily consisting of accrued interest.

On April 12, 2006, the OEB announced its decision regarding the company's rate application in respect of the distribution business of Hydro One Networks. As part of this decision, the OEB also approved the distribution-related deferral account balances sought by Innisfil Hydro. The OEB ordered that the approved balances be recovered on a straight-line basis over a four year period from May 1, 2006 to April 30, 2010. The RARAI II includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest.

Regulatory liabilities

Retail settlement variance accounts

Innisfil Hydro has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's *Accounting Procedures Handbook*. The OEB's December 9, 2004 decision allowed for recovery of retail settlement variance amounts accumulated prior to December 31, 2003, inclusive of interest, within the RARA I. The OEB's April 12, 2006 decision allowed for recovery of retail settlement variance amounts accumulated since January 1, 2004 and forecasted through to April 30, 2006, inclusive of interest, within the RARA II. The company has accumulated a net liability in its retail settlement variance accounts since May 1, 2006 and anticipates that the OEB will include the net balance of this regulatory account in future rates.

Pre-market opening energy variance

The pre-market opening energy variance account was established for the purpose of recording the estimated difference between the company'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 starting January 1, 2001 and ending May 1, 2002. This amount was recorded as distribution revenue upon OEB approval on April 12, 2006.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2006

7. Bank indebtedness

The company has available a committed credit facility in the amount of $3,000,000. The company used $1,144,016 (2005 - $1,144,016) by way of a bank letter of credit as described in Note 12. The letter of credit bears interest at the prime rate of a Canadian chartered bank less .25% per annum. The company has no outstanding indebtedness at the end of 2006 (2005 - $1,000,000). The facility is secured by a general security agreement conveying first fixed and floating charges over the property, assets, rights and interests of the company.

8. Long term debt

	2006	2005
Debentures payable to the Town	$ 6,640,000	$ 7,080,000
Note payable to the Town	2,107,444	2,107,444
	8,747,444	9,187,444
Less: current portion	2,592,444	440,000
	$ 6,155,000	$ 8,747,444

The debentures are payable to the Town and bear interest at various rates ranging from 8.0% to 9.75%. Principal payments are due annually on March 31 until 2015.

The note is payable to the Town and payments are interest only at 7.25%. The note is callable with one year plus one day's notice, due December 31, 2007.

Principal payments due in each of the next five years are as follows:

2007	$ 2,592,444
2008	534,000
2009	589,000
2010	650,000
2011	716,000

9. Capital stock

	2006	2005
Authorized:		
The company is authorized to issue an unlimited number of common shares and an unlimited number of preference shares.		
Issued:		
1,000 common shares	$ 10,852,444	$ 10,852,444

10. Public liability insurance

The company is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE), which was created on January 1, 1987. A reciprocal insurance exchange may be defined as a group of persons formed for the purpose of exchanging reciprocal contracts of indemnity or inter-insurance with each other through the same attorney. MEARIE has provided comprehensive liability insurance to the company of $20,000,000 per occurrence.

11. Payments in lieu of taxes

Expenses

The company is required to compute and remit to the OEFC payments in lieu of income taxes (PILS). PILS are computed in accordance with rules for computing income, capital and other taxes provided for in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) as modified by The Electricity Act, 1998 and related regulations.

	2006	2005
Income before provision for PILS	$ 2,111,827	$ 871,601
Federal and Ontario statutory income tax rates	36.12%	36.12%
Provision for PILS at statutory rate	$ 762,792	$ 314,822
Temporary differences		
Amortization in excess of capital cost allowance	164,770	192,079
Net regulatory assets not deducted for accounting	161,085	(254,112)
Adjustment of prior year's provisions	17,552	(1,648)
Other	(19,427)	(21,027)
Net temporary differences	323,980	(84,708)
Permanent differences		
Capital cost allowance on appraisal increment	(38,598)	(40,745)
Small business deduction	-	(34,000)
Other	(3,174)	3,601
Net permanent differences	(41,772)	(71,114)
Provision for PILS	$ 1,045,000	$ 159,000
Effective income tax rate	49.48%	18.27%

11. Payments in lieu of taxes (Continued)

Future taxes

Future income taxes have not been recorded as they are expected to be reflected through future rates.

Significant components of the corporation's deductible (taxable) temporary differences at year end are as follows:

	2006	2005
Regulatory assets	$ (352,580)	$ (798,552)
Property and equipment	4,494130	4,057,878
	$ 4,141,550	$ 3,259,326

12. Contingent liabilities

Security

Purchasers of electricity in Ontario, through the Independent Electricity Systems Operator (IESO) are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if the company fails to make a payment required by default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2006, the company provided prudential support using bank letters of credit of $1,144,016.

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

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

12. Contingent liabilities (Continued)

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

After the release by the Supreme Court of Canada of its 2004 decision in the Consumers Gas case, the plaintiffs in the LDC late payment penalties class action indicated their intention to proceed with litigation against the LDCs. To date, no formal steps have been taken to move the action forward. The electric utilities intend to respond to the action if and when it proceeds on the basis that the LDCs' situation may be distinguishable from that of Consumers Gas.

At this time it is not possible to quantify this effect, if any, on the financial statements of the company.

Application of entitlement

There is currently a proposed application being developed to be sent to the Supreme Court of Justice for determination for entitlement of Economic Evaluation contributions. At this time it is not possible to quantify the effect, if any, on the financial statements of the company.

13. Other revenue	**2006**	2005
Late payment charges	$ **86,955**	$ 87,298
Interest	**265,207**	161,953
Pole rentals	**145,439**	136,333
Miscellaneous service revenues	**45,467**	51,868
Management fee charged to affiliate	**52,673**	47,274
Miscellaneous non-operating income	**11,672**	23,216
	$ **607,413**	$ 507,942

14. Pension plan

The company makes contributions to Ontario Municipal Employees Retirement System ("OMERS"), a multi-employer plan, on behalf of its staff. The plan is a contributory defined benefit plan, which specifies the amount of the retirement benefit to be received by the employees based on the length of service and rates of pay.

Contributions were made at rates ranging from 6.5% to 9.6% of employee contributory earnings, depending upon the level of earnings. As a result, the company made contributions in 2006 totaling $95,801 for the current service (2005- $81,109).

15. Financial instruments

The company's financial instruments consist of receivables, unbilled revenue, due to (from) related party, payables and accruals, customer and retailer deposits and long-term debt. Unless otherwise noted, it is management's opinion that the company is not exposed to significant interest, currency or credit risks arising from these financial instruments. The fair value of these financial instruments approximate their carrying values, unless otherwise noted.

16. Comparative figures

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

17. Supplemental cash flow information

	2006	2005
Change in non cash operation working capital		
Receivables	**$ (1,096,937)**	$ 389,652
Unbilled	**118,032**	(1,706)
Due from related party	**49,909**	(13,074)
Inventory	**(42,511)**	(29,646)
Payment in lieu of taxes	**718,524**	(254,424)
Prepaids	**(4,381)**	(28,470)
Payables and accruals	**913,122**	(1,167,868)
Due to related party	**(10,725)**	(9,476)
Customer credit balances and deposits	**(362,824)**	227,820
	$ 282,209	$ (887,191)
Supplemental cash flow information		
Interest paid	**$ 876,033**	$ 922,932
Payments in lieu of taxes paid	**359,152**	905,086
Interest received	**267,641**	158,840

Grant Thornton

Financial Statements

Innisfil Hydro Distribution Systems Limited

December 31, 2007

Contents

Grant Thornton

Auditors' report

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To the directors of

Innisfil Hydro Distribution Systems Limited

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

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

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2007 and the results of its operations and cash flows for year then ended in accordance with Canadian generally accepted accounting principles.

Grant Thornton LLP

Barrie, Ontario — Chartered accountants

March 12, 2008 — Licensed public accountants

Innisfil Hydro Distribution Systems Limited
Statements of earnings and retained earnings

Year ended December 31	2007	2006
Revenue		
Sale of power	$ 16,686,544	$ 16,807,414
Distribution	6,511,929	6,842,889
	23,198,473	23,650,303
Cost of power		
Power purchased	16,686,544	16,807,414
Gross margin	6,511,929	6,842,889
Other revenue (Note 13)	464,885	607,413
Expenses		
Distribution	1,128,854	1,017,296
Billing and collecting	923,175	829,594
Administration	1,167,085	1,101,657
Amortization	1,666,910	1,550,134
	4,886,024	4,498,681
Earnings from operations	2,090,790	2,951,621
Interest on long term debt	786,849	839,794
Earnings before payments in lieu of taxes	1,303,941	2,111,827
Payments in lieu of taxes (Note 15)	311,102	1,045,000
Net earnings	$ 992,839	$ 1,066,827
Retained earnings, beginning of year	$ 1,668,700	$ 1,143,873
Net earnings	992,839	1,066,827
Dividends	(625,000)	(542,000)
Retained earnings, end of year	$ 2,036,539	$ 1,668,700

See accompanying notes to the financial statements.

Innisfil Hydro Distribution Systems Limited
Balance sheet
December 31

	2007	2006
Assets		
Current		
Cash and cash equivalents	$ 2,709,332	$ 2,090,951
Receivables	1,982,858	2,049,672
Due from related party (Note 4)	-	39,690
Notes due from related party (Note 4)	-	996,000
Unbilled revenue	2,410,437	2,633,137
Inventory	248,298	262,724
Payments in lieu of taxes recoverable	375,786	-
Prepaids	210,581	176,333
	7,937,292	8,248,507
Property and equipment (Note 5)	17,069,201	17,251,653
Long Term Investment (Note 6)	7,240	-
Regulatory assets (Notes 7)	1,117,232	1,279,041
	$ 26,130,965	$ 26,779,201
Liabilities		
Current		
Payables and accruals	$ 3,042,646	$ 2,875,584
Customer credit balances and deposits	549,179	483,192
Payments in lieu of taxes payable	-	374,614
Due to related party (Note 4)	162,950	161,850
Current portion of long-term debt	534,000	2,592,444
	4,288,775	6,487,684
Customer and retailer deposits	479,670	438,286
Regulatory liabilities (Note 7)	189,472	621,466
Long term debt (Note 9)	7,728,444	6,155,000
	12,686,361	13,702,436
Shareholder's Equity		
Capital stock (Note 10)	10,852,444	10,852,444
Development charges transferred to equity	555,621	555,621
Retained earnings	2,036,539	1,668,700
	13,444,604	13,076,765
	$ 26,130,965	$ 26,779,201

Commitment and Contingent liabilities (Notes 11 and 12)

On Behalf of the Board

_______________ Director _______________ Director

See accompanying notes to the financial statements.

Innisfil Hydro Distribution Systems Limited
Statement of cash flows

Year ended December 31	2007	2006
Increase (decrease) in cash and cash equivalents		
Operating		
Net earnings	$ 992,839	$ 1,066,827
Gain on disposal	(7,240)	-
Amortization	1,666,910	1,550,134
	2,652,509	2,616,961
Customers and retailer deposits	41,384	198,478
Change in non-cash operating working capital (Note 16)	789,131	282,209
	3,483,024	3,097,648
Financing		
Banker acceptance advances	-	(1,000,000)
Capital contributions	642,594	1,020,015
Dividends	(625,000)	(542,000)
Repayment of long term debt	(485,000)	(440,000)
Equity development charges	-	242,323
	(467,406)	(719,662)
Investing		
Net additions to property and equipment	(2,127,052)	(3,527,959)
Net reduction to regulatory liabilities	(431,994)	(565,335)
Net reduction to regulatory assets	161,809	624,596
	(2,397,237)	(3,468,698)
Net increase (decrease) in cash	618,381	(1,090,712)
Cash and cash equivalents, beginning of year	2,090,951	3,181,663
Cash and cash equivalents, end of year	$ 2,709,332	$ 2,090,951

See accompanying notes to the financial statements.

1. Nature of operations

The Company distributes electricity under license from the Ontario Energy Board (OEB). The Electricity Act, 1998 provides for a competitive marketplace in the sale of electricity. The Ontario Energy Board Act, 1998 (Ontario) (OEBA) conferred on the Ontario Energy Board (OEB) increased powers and responsibilities to regulate the electricity industry. These powers and responsibilities include the power to approve or fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity consumers, and the responsibility for ensuring that distribution companies fulfil obligations to connect and service customers. The OEB may also prescribe license requirements and conditions to electricity distributors, which may include among other things, specified accounting records, regulatory accounting principles, separation of accounts for distinct businesses and filing and process requirements for rate setting purposes.

2. Summary of significant accounting policies

Cash and cash equivalents

Cash and cash equivalents include cash, short term investments and bank balances.

Revenue recognition

Sale of power, distribution and related revenues are based on OEB approved unbundled rates and are recognized as power is delivered to customers. The Company estimates the monthly revenue for the period based on customer's usage because customer meters are not generally read at the end of each month. Unbilled revenue is recognized for customer usage not billed at December 31, 2007.

Other revenue is recognized as services are rendered.

Inventory

Inventory consists of repair parts, supplies and materials held for future capital expansion and is valued at lower of average cost and estimated net realizable value.

Rate-setting

The electricity distribution business is subject to rate regulation by the OEB. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. This change in timing gives rise to the recognition of regulatory assets and liabilities. These regulatory assets and liabilities reflect the fact that revenue and expenses are recognized in the financial statements in different periods consistent with their inclusion in rates, as directed by the regulator, than would be the case for an enterprise that is unregulated. Specific regulatory assets and liabilities recognized at December 31, 2007 are disclosed in Notes 7.

2. Summary of significant accounting policies (Continued)

Rate-setting (Continued)

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

Amortization

Property and equipment are amortized using the straight-line method over periods approximating their estimated useful lives as follows:

Land rights	50 years
Buildings	25 years
Distribution station	30 years
Distribution system	25 years
System supervisory equipment	15 years
Other equipment	5-10 years
Computer hardware	5 years
Computer software	3 years
Contributions in aid of construction	25 years

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

Fixed assets retirement obligations

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

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

2. Summary of significant accounting policies (Continued)

Corporate income and capital taxes

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

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

Use of estimates

In preparing the Company's financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenue and expenditures during the year. Actual results could differ from these estimates.

3. Future accounting pronouncements

Financial instruments, hedges, and comprehensive income

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

3. Future accounting pronouncements (continued)

Financial instruments disclosures and presentation

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

Capital disclosures

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

Inventories

Effective January 1, 2008, the Company will be required to adopt CICA Handbook Section 3031 "Inventories". This new standard replaces the existing Section 3030 of the same name and contains requirements on measurement and disclosure of inventories and revises and enhances the requirements for assigning costs to inventories. This new standard also allows for reversal of previous write-downs. The Company has not yet determined the impact that the adoption of this change will have on the disclosure in its financial statements.

General standards on financial statement presentation

Effective January 1, 2008, the Company will be required to adopt CICA Handbook Section 1400 "General Standards on Financial Statement Presentation". This new standard amends the previous standard to include requirements to assess and disclose an entity's ability to continue as a going concern. The Company does not expect the adoption of this change to have an impact on its financial statements.

Rate regulated Operations

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

3. Future accounting pronouncements (continued)

future income taxes expected to be included in future rates and recovered from or paid to future customers.

There will be adjustments within AcG-19 to reflect the changes made for Sections 1100 and 3465 of the CICA Handbook. The Company has not yet determined the impact that the adoption of this change will have on its financial statements.

4. Related party transactions

The Company had the following related party transactions:

	2007	2006
Innisfil Energy Services Limited ("IESL") - affiliated company controlled by shareholder		
Services provided	**$ 46,286**	$ 51,396
Interest on advances	**14,121**	55,012
The Corporation of The Town of Innisfil ("Town") - shareholder		
Interest on advances	**$ 764,724**	$ 810,915
Electrical services billed	**1,102,859**	1,090,765
Professional services billed	**81,488**	65,149
Other services billed	**45,165**	15,838
Dividends paid	**625,000**	542,000
Municipal taxes	**49,722**	48,638
Other expenses	**32,383**	85,099

Balances outstanding at December 31:

	2007	2006
Due from Innisfil Energy Services Limited	**$ -**	$ 39,690
Due to Innisfil Energy Services Limited.	**12,922**	-
Accrued interest, due to the Town	**150,028**	161,850
Note and debenture payable to the Town	**$ 8,262,444**	$ 8,747,444
Notes due from Innisfil Energy Services Limited	**$ -**	$ 996,000
Dividend payable to the Town, included in payables	**$ 156,250**	$ 117,000
Due from Town, included in receivables	**102,969**	88,681
Due to the Town, included in payables	**12,200**	-

During the year, the Company provided financial, management and accounting services to IESL in the amount of $46,286 (2006 - $51,396). These transactions have been recorded in these financial statements at the carrying amounts, which were equal to historical cost or fair value.

4. Related party transactions (Continued)

Fair value represents fees for equivalent services provided to third parties in the normal course of operations as prescribed by regulation. At the end of the year, $12,922 was due to IESL. (In 2006 – $39,690 was due from IESL)

The Company provides electricity and services to the Town. These transactions are in the normal course of operations and are measured at the exchange amount, which is equal to fair value as prescribed by regulation. During the year, the Company billed electricity and services to the Town in the amount of $1,102,859 (2006 - $1,090,765) and professional services in the amount of $81,488 (2006 - $65,149). At the end of the year, $102,969 (2006 - $88,681) was due for these services. During the year, the Company paid municipal taxes of $49,722 (2006 - $48,638) and other expenses of $32,383 (2006 - $94,699) to the Town.

5. Property and equipment

			2007	2006
	Cost	Accumulated Amortization	Net Book Value	Net Book Value
Land	$ 484,399	$ -	**$ 484,399**	$ 484,399
Land rights	956,027	494,921	**461,106**	476,348
Building and fixtures	607,362	161,595	**445,767**	426,164
Distribution station	4,259,234	1,989,357	**2,269,877**	2,378,961
Distribution system	35,126,920	19,277,722	**15,849,198**	15,551,881
System supervisory equipment	1,104,718	460,137	**644,581**	670,592
Other equipment	754,668	557,901	**196,767**	188,670
Computer hardware	708,303	532,718	**175,585**	116,974
Computer software	774,930	576,846	**198,084**	119,467
Contributions in aid of construction	(4,314,831)	(658,668)	**(3,656,163)**	(3,161,803)
	$ 40,461,730	$ 23,392,529	**$ 17,069,201**	$ 17,251,653

6. Long term investment

The long term investment is recorded at cost and consists of 7,240 shares of a private company that mainly provides settlement services to the electric utilities of Ontario.

7. Regulatory assets and liabilities

Regulatory assets and liabilities arise as a result of the rate-making process. Innisfil Hydro has recorded the following regulatory assets and liabilities (Note 2)

		2007		2006
Regulatory assets				
Regulatory asset recovery account I and II	$	**373,311**	$	1,132,273
Retail settlement variance accounts		**617,517**		-
Other		**126,404**		146,768
Total regulatory assets	$	**1,117,232**	$	1,279,041
Regulatory liabilities				
Other	$	**189,472**	$	347,608
Retail settlement variance accounts		**-**		273,858
Total regulatory liabilities	$	**189,472**	$	621,466

Regulatory assets

Regulatory asset recovery account I and II (RARA I and RARA II)

On December 9, 2004, the OEB issued a decision on the prudence of the distribution-related deferral account balances for which recovery was sought by Innisfil Hydro in its May 31, 2004 application. Amounts for which recovery was approved represented balances incurred prior to December 31, 2003, plus associated interest. The OEB ordered that the approved amounts be aggregated into a single regulatory account to be recovered on a straight-line basis over the period ending April 30, 2008. The RARA I includes distribution business low-voltage services amounts, deferred market ready expenditures, retail settlement variance amounts, and other amounts primarily consisting of accrued interest.

On April 12, 2006, the OEB announced its decision regarding the Company's rate application in respect of the distribution business of Hydro One Networks. As part of this decision, the OEB also approved the distribution-related deferral account balances sought by Innisfil Hydro. The OEB ordered that the approved balances be recovered on a straight-line basis over a four year period from May 1, 2006 to April 30, 2010. The RARAI II includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest.

Retail settlement variance accounts

Innisfil Hydro has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's *Accounting Procedures Handbook.* The OEB's December 9, 2004 decision allowed for recovery of retail settlement variance amounts accumulated prior to December 31, 2003, inclusive of interest, within the RARA I. The OEB's April 12, 2006 decision allowed for recovery of retail settlement variance amounts accumulated since January 1, 2004 and forecasted through to April 30, 2006, inclusive of interest, within the RARA II.

7. Regulatory assets and liabilities (Continued)

The Company has accumulated a net asset in its retail settlement variance accounts since May 1, 2006 and anticipates that the OEB will include the net balance of this regulatory account in future rates.

Regulatory liabilities

The other regulatory liability consists of amounts owing to Hydro One for recovery of their regulatory asset charges from embedded distributors as deemed by the OEB and are being paid on a monthly basis.

8. Bank indebtedness

The Company has available a committed credit facility in the amount of $3,000,000. The Company used $938,146 (2006 - $1,144,016) by way of a bank letter of credit as described in Note 12. The letter of credit bears interest at the prime rate of a Canadian chartered bank less .25% per annum. The Company has no outstanding indebtedness at the end of 2007 (2006 - Nil). The facility is secured by a general security agreement conveying first fixed and floating charges over the property, assets, rights and interests of the Company.

9. Long term debt

	2007	2006
Debentures payable to the Town	$ 6,155,000	$ 6,640,000
Note payable to the Town	2,107,444	2,107,444
	8,262,444	8,747,444
Less: current portion	534,000	2,592,444
	$ 7,728,444	$ 6,155,000

The debentures are payable to the Town and bear interest at various rates ranging from 8.0% to 9.75%. Principal payments are due annually on March 31 until 2015.

The note is payable to the Town, due December 31, 2010 and payments are interest only at the OEB prescribed quarterly rate.

Principal payments due in each of the next five years are as follows:

2008	$ 534,000
2009	589,000
2010	2,757,444
2011	716,000
2012	790,000

10. Capital stock

	2007	2006
Authorized:		
The Company is authorized to issue an unlimited number of common shares and an unlimited number of preference shares.		
Issued:		
1,000 common shares	$ 10,852,444	$ 10,852,444

11. Commitment

Effective January 1, 2009, the Company has agreed to pay 50% of the premiums for early retirees from the age of 55 to 65 who have a minimum of 15 years of service with Innisfil Hydro for specific benefit packages outlined in the conditions of employment and the collective bargaining agreement.

12. Contingent liabilities

Security

Purchasers of electricity in Ontario, through the Independent Electricity Systems Operator (IESO) are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if the company fails to make a payment required by default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2007, the Company provided prudential support using bank letters of credit of $938,146.

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

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

On April 22, 2004, the Supreme Court of Canada released a decision in the Consumers Gas case rejecting all of the defences which had been raised by Enbridge, although the Court did not permit the Plaintiff class to recover damages for any period prior to the issuance of the Statement of Claim in 1994 challenging the validity of late payment penalties.

12. Contingent liabilities (Continued)

The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge. In 2007, Enbridge filed an application to the Ontario Energy Board ("OEB") to recover the Court-approved amount and related amounts from ratepayers. On February 4, 2008 the OEB approved recovery of the said amounts from ratepayers over a five year period.

After the release by the Supreme Court of Canada of its 2004 decision in the Consumers Gas case, the plaintiffs in the LDC late payment penalties class action indicated their intention to proceed with litigation against the LDCs. To date, no formal steps have been taken to move the action forward. The electric utilities intend to respond to the action if and when it proceeds on the basis that the LDCs' situation may be distinguishable from that of Consumers Gas.

At this time it is not possible to quantify this effect, if any, on the financial statements of the Company.

Application of entitlement

There is currently a proposed application being developed to be sent to the Supreme Court of Justice for determination for entitlement of Economic Evaluation contributions. At this time it is not possible to quantify the effect, if any, on the financial statements of the Company.

13. Other revenue

	2007	2006
Late payment charges	$ 92,218	$ 86,955
Interest	117,125	265,207
Pole rentals	144,994	145,439
Miscellaneous service revenues	42,348	45,467
Management fee charged to affiliate	56,905	52,673
Miscellaneous non-operating income	11,295	11,672
	$ 464,885	$ 607,413

14. Pension plan

The Company makes contributions to Ontario Municipal Employees Retirement System ("OMERS"), a multi-employer plan, on behalf of its staff. The plan is a contributory defined benefit plan, which specifies the amount of the retirement benefit to be received by the employees based on the length of service and rates of pay.

Contributions were made at rates ranging from 6.5% to 9.6% of employee contributory earnings, depending upon the level of earnings. As a result, the company made contributions in 2007 totaling $98,261 for the current service (2006 - $95,801).

15. Payments in lieu of taxes

The Company is required to compute and remit to the OEFC payments in lieu of income taxes (PILS). PILS are computed in accordance with rules for computing income, capital and other taxes provided for in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) as modified by The Electricity Act, 1998 and related regulations.

	2007	2006
Income before provision for PILS	$ 1,303,941	$ 2,111,827
Federal and Ontario statutory income tax rates	36.12%	36.12%
Provision for PILS at statutory rate	$ 470,983	$ 762,792
Temporary differences		
Amortization in excess of capital cost allowance	178,246	164,770
Net effect of regulatory assets	(267,988)	161,085
Adjustment of prior year's provisions	(8,876)	17,552
Other	(22,682)	(19,427)
Net temporary differences	(121,300)	323,980
Permanent differences		
Capital cost allowance on appraisal increment	(36,536)	(38,598)
Other	(2,045)	(3,174)
Net permanent differences	(38,581)	(41,772)
Provision for PILS	$ 311,102	$ 1,045,000
Effective income tax rate	23.86%	49.48%

Future taxes

Future income taxes have not been recorded as they are expected to be reflected through future rates.

Significant components of the Company's deductible (taxable) timing differences at year end are as follows:

	2007	2006
Regulatory assets	$ (1,094,517)	$ (352,580)
Property and equipment	4,864,581	4,494,130
	$ 3,770,064	$ 4,141,550

16. Supplemental cash flow information

	2007	2006
Change in non cash operation working capital		
Receivables	$ 66,814	$ (1,096,937)
Unbilled	222,700	118,032
Due from related party	1,036,790	39,184
Inventory	14,426	(42,511)
Payment in lieu of taxes	(750,400)	718,524
Prepaids	(34,248)	(4,381)
Payables and accruals	167,062	913,122
Customer credit balances and deposits	65,987	(362,824)
	$ 789,131	$ 282,209
Supplemental cash flow information		
Interest received	$ 124,381	$ 267,641
Interest paid	$ 821,408	$ 876,033
Payments in lieu of taxes paid	$ 1,092,318	$ 359,152

17. Public liability insurance

The Company is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE), which was created on January 1, 1987. A reciprocal insurance exchange may be defined as a group of persons formed for the purpose of exchanging reciprocal contracts of indemnity or inter-insurance with each other through the same attorney. MEARIE has provided comprehensive liability insurance to the Company of $20,000,000 per occurrence.

18. Financial instruments

The Company's financial instruments consist of receivables, unbilled revenue, due to (from) related party, payables and accruals, customer and retailer deposits and long-term debt. Unless otherwise noted, it is management's opinion that the Company is not exposed to significant interest, currency or credit risks arising from these financial instruments. The fair value of these financial instruments approximate their carrying values, unless otherwise noted.

19. Comparative figures

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

PRO FORMA FINANCIAL STATEMENTS - 2008 AND 2009:

The Innisfil Hydro Pro Forma Statements for the 2008 Bridge Year and the 2009 Test Year accompany this Schedule as Appendix A

APPENDIX A

COPY OF INNISFIL HYDRO 2008 PRO FORMA STATEMENTS

INNISFIL HYDRO
PRO FORMA FINANCIAL STATEMENTS
AT
DECEMBER 31 2008

Account Description	Total
1050-Current Assets	
1005-Cash	229,614.20
1010-Cash Advances and Working Funds	1,550.00
1020-Interest Special Deposits	-
1040-Other Special Deposits	168,000.00
1070-Current Investment	493,000.00
1100-Customer Accounts Receivable	2,020,700.00
1102-Accounts Receivable - Services	-
1104-Accounts Receivable - Recoverable Work	230,000.00
1105-Accounts Receivable - Merchandise, Jobbing, etc.	-
1110-Other Accounts Receivable	237,000.00
1120-Accrued Utility Revenues	2,400,000.00
1130-Accumulated Provision for Uncollectible Accounts--Credit	(201,700.00)
1140-Interest and Dividends Receivable	-
1150-Rents Receivable	54,000.00
1180-Prepayments	215,000.00
1200-Accounts Receivable from Associated Companies	-
1210-Notes Receivable from Associated Companies	-
1050-Current Assets Total	**5,847,164.20**

1100-Inventory	
1330-Plant Materials and Operating Supplies	270,000.00
1305-Fuel Stock	-
1350-Other Materials and Supplies	-
1100-Inventory Total	**270,000.00**

1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	14,480.00
1410-Other Special or Collateral Funds	310,000.00
1460-Other Non-Current Assets	-
1150-Non-Current Assets Total	**324,480.00**

1200-Other Assets and Deferred Charges	
1508-Other Regulatory Assets	173,477.00
1518-RCVARetail	(18,727.00)
1525-Miscellaneous Deferred Debits	-
1548-RCVASTR	36,437.00
1550-LV Variance Account	245,236.00
1555-Smart Meters Capital Variance Account	16,847.00
1556-Smart Meters OM&A Variance Account	-
1562-Deferred Payments in Lieu of Taxes	(704,231.00)
1563-Deferred Payments in Lieu of Taxes contra	704,231.00
1565-Conservation and Demand Management Expenditures and Recoveries	-
1566-CDM Contra Account	-
1570-Qualifying Transition Costs	-
1571-Pre-market Opening Energy Variance	-
1572-Extraordinary Event Costs	-
1580-RSVAWMS	(329,876.00)
1582-RSVAONE-TIME	67,775.00
1584-RSVANW	(286,137.00)
1586-RSVACN	449,370.00
1588-RSVAPOWER	490,858.00
1590-Recovery of Regulatory Asset Balances	44,981.00
1200-Other Assets and Deferred Charges Total	**890,241.00**

1450-Distribution Plant	
1805-Land	283,350.00
1806-Land Rights	-
1808-Buildings and Fixtures	-
1810-Leasehold Improvements	86,252.00
1815-Transformer Station Equipment - Normally Primary above 50 kV	
1820-Distribution Station Equipment - Normally Primary below 50 kV	4,318,083.93
1825-Storage Battery Equipment	-
1830-Poles, Towers and Fixtures	7,034,076.85
1835-Overhead Conductors and Devices	9,802,504.14
1840-Underground Conduit	1,768,346.86
1845-Underground Conductors and Devices	6,709,888.92
1850-Line Transformers	7,784,462.66
1855-Services	3,436,857.93
1860-Meters	1,856,704.59
1450-Distribution Plant Total	**43,080,527.88**

1500-General Plant	
1905-Land	201,049.00
1906-Land Rights	971,527.03
1908-Buildings and Fixtures	692,361.76
1915-Office Furniture and Equipment	266,994.69
1920-Computer Equipment - Hardware	768,802.62
1925-Computer Software	865,329.85
1930-Transportation Equipment	330,841.38
1935-Stores Equipment	19,473.73
1940-Tools, Shop and Garage Equipment	158,636.44
1945-Measurement and Testing Equipment	17,102.25
1950-Power Operated Equipment	-
1955-Communication Equipment	-
1960-Miscellaneous Equipment	-
1970-Load Management Controls - Customer Premises	-
1980-System Supervisory Equipment	1,213,515.41
1995-Contributions and Grants - Credit	(4,819,830.80)
1500-General Plant Total	**685,803.36**

1550-Other Capital Assets	
2055-Construction Work in Progress--Electric	-
2060-Electric Plant Acquisition Adjustment	-
2070-Other Utility Plant	-
1875-Street Lighting	46,389.00
1550-Other Capital Assets Total	**46,389.00**

1600-Accumulated Amortization	
2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(25,078,320.50)
2160-Accumulated Amortization of Other Utility Plant	-
1600-Accumulated Amortization Total	**(25,078,320.50)**

Total Assets	26,066,284.94

1650-Current Liabilities	
2205-Accounts Payable	75,000.00
2208-Customer Credit Balances	270,000.00
2210-Current Portion of Customer Deposits	230,000.00
2220-Miscellaneous Current and Accrued Liabilities	745,000.00
2240-Accounts Payable to Associated Companies	12,988.00
2250-Debt Retirement Charges(DRC) Payable	141,000.00
2252-Transmission Charges Payable	522,000.00
2256-IESO Payable	1,565,900.00
2260-Current portion of Long Term Debt	589,000.00
2268-Accrued interest on LTD	137,012.00
2290-Commodity Taxes	190,000.00
2292-Payroll Deductions / Expenses Payable	1,100.00
2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	400,000.00
2296-Future Income Taxes - Current	-
1650-Current Liabilities Total	**4,879,000.00**

1700-Non-Current Liabilities	
2306-Employee Future Benefits	-
2310-Vested Sick Leave Liability	
2320-Other Miscellaneous Non-Current Liabilities	-
2335-Long Term Customer Deposits	447,163.00
2340-Collateral funds liability	32,837.00
2350-Future Income Tax - Non-Current	-
2405-Other Regulatory Liabilities	30,336.00
2425-Other Deferred Credits	-
1700-Non-Current Liabilities Total	**510,336.00**

1800-Long-Term Debt	
2550-Advances from Associated Companies	7,139,444.00
1800-Long-Term Debt Total	**7,139,444.00**

1850-Shareholders' Equity	
3005-Common Shares Issued	10,852,444.00
3010-Contributed Surplus	-
3022-Development charges transferred	555,619.94
3030-Miscellaneous Paid-In Capital	-
3045-Unappropriated Retained Earnings	1,999,240.02
3046-Balance Transferred From Income	755,200.98
3049-Dividends Payable-Common Shares	(625,000.00)
1850-Shareholders' Equity Total	**13,537,504.94**

Total Liabilities & Shareholder's Equity	**26,066,284.94**

Balance Sheet Total	(0.00)

2008 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(8,752,935.00)
4010-Commercial Energy Sales	-
4015-Industrial Energy Sales	-
4020-Energy Sales to Large Users	-
4025-Street Lighting Energy Sales	(89,996.00)
4030-Sentinel Lighting Energy Sales	(7,133.00)
4035-General Energy Sales	(4,027,402.00)
4050-Revenue Adjustment	
4055-Energy Sales for Resale	-
4060-Interdepartmental Energy Sales	
4062-Billed WMS	(1,464,960.00)
4066-Billed NW	(1,212,942.00)
4068-Billed CN	(816,010.00)
4075-Billed LV	(495,642.00)
3000-Sales of Electricity Total	**(16,867,020.00)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(6,649,731.98)
4082-Retail Services Revenues	(24,909.00)
4084-Service Transaction Requests (STR) Revenues	(1,360.00)
4090-Electric Services Incidental to Energy Sales	
3050-Revenues From Services - Distirbution Total	**(6,676,000.98)**
3100-Other Operating Revenues	
4210-Rent from Electric Property	(145,208.00)
4220-Other Electric Revenues	
4225-Late Payment Charges	(89,542.00)
4230-Sales of Water and Water Power	
4235-Miscellaneous Service Revenues	(109,490.00)
3100-Other Operating Revenues Total	**(344,240.00)**
3150-Other Income & Deductions	
4325-Revenues from Merchandise, Jobbing, Etc.	-
4330-Costs and Expenses of Merchandising, Jobbing, Etc.	-
4355-Gain on Disposition of Utility and Other Property	-
4375-Revenues of Non-Utility Operations	(212,597.00)
4380-Expenses of Non-Utility Operations	190,096.00
4390-Miscellaneous Non-Operating Income	(7,053.00)
4398-Foreign Exchange Gains and Losses, Including Amortization	-
3150-Other Income & Deductions Total	**(29,554.00)**
3200-Investment Income	
4405-Interest and Dividend Income	(104,600.00)
3200-Investment Income Total	**(104,600.00)**
3350-Power Supply Expenses	
4705-Power Purchased	12,877,467.00
4708-Charges-WMS	1,228,676.00
4710-Cost of Power Adjustments	-
4714-Charges-NW	1,212,942.00
4715-System Control and Load Dispatching	
4716-Charges-CN	816,010.00
4730-Rural Rate Assistance Expense	236,284.00
4750-LV Charges	495,642.00
3350-Power Supply Expenses Total	**16,867,021.00**

3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	70,525.00
5010-Load Dispatching	5,800.00
5012-Station Buildings and Fixtures Expense	38,450.00
5014-Transformer Station Equipment - Operation Labour	-
5015-Transformer Station Equipment - Operation Supplies and Expenses	-
5016-Distribution Station Equipment - Operation Labour	7,100.00
5017-Distribution Station Equipment - Operation Supplies and Expenses	1,850.00
5020-Overhead Distribution Lines and Feeders - Operation Labour	36,850.00
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	32,400.00
5030-Overhead Subtransmission Feeders - Operation	2,950.00
5035-Overhead Distribution Transformers- Operation	3,350.00
5040-Underground Distribution Lines and Feeders - Operation Labour	25,800.00
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	8,600.00
5055-Underground Distribution Transformers - Operation	250.00
5065-Meter Expense	59,900.00
5070-Customer Premises - Operation Labour	45,000.00
5075-Customer Premises - Materials and Expenses	9,000.00
5085-Miscellaneous Distribution Expense	382,175.00
5095-Overhead Distribution Lines and Feeders - Rental Paid	3,700.00
5096-Other Rent	-
3500-Distribution Expenses - Operation Total	**733,700.00**

3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	11,100.00
5110-Maintenance of Buildings and Fixtures - Distribution Stations	-
5114-Maintenance of Distribution Station Equipment	35,100.00
5120-Maintenance of Poles, Towers and Fixtures	39,600.00
5125-Maintenance of Overhead Conductors and Devices	121,200.00
5130-Maintenance of Overhead Services	57,150.00
5135-Overhead Distribution Lines and Feeders - Right of Way	179,050.00
5145-Maintenance of Underground Conduit	-
5150-Maintenance of Underground Conductors and Devices	10,950.00
5155-Maintenance of Underground Services	53,850.00
5160-Maintenance of Line Transformers	42,100.00
5175-Maintenance of Meters	30,000.00
3550-Distribution Expenses - Maintenance Total	**580,100.00**

3650-Billing and Collecting	
5305-Supervision	42,400.00
5310-Meter Reading Expense	142,800.00
5315-Customer Billing	367,100.00
5320-Collecting	322,000.00
5330-Collection Charges	50.00
5335-Bad Debt Expense	29,000.00
5340-Miscellaneous Customer Accounts Expenses	47,600.00
3650-Billing and Collecting Total	**950,950.00**

3700-Community Relations	
5405-Supervision	-
5410-Community Relations - Sundry	8,500.00
5415-Energy Conservation	-
5420-Community Safety Program	-
5425-Miscellaneous customer accounts expenses	2,100.00
5510-Demonstrating and Selling Expense	-
5515-Advertising Expense	-
5520-Miscellaneous Sales Expense	-
3700-Community Relations Total	**10,600.00**
3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	197,050.00
5610-Management Salaries and Expenses	152,225.00
5615-General Administrative Salaries and Expenses	424,725.00
5620-Office Supplies and Expenses	71,750.00
5625-Administrative Expense Transferred Credit	-
5630-Outside Services Employed	54,500.00
5635-Property Insurance	42,500.00
5640-Injuries and Damages	39,000.00
5645-Employee Pensions and Benefits	-
5655-Regulatory Expenses	28,310.00
5660-General Advertising Expenses	-
5665-Miscellaneous General Expenses	67,705.00
5670-Rent	330.00
5675-Maintenance of General Plant	144,580.00
5680-ESA fees	14,500.00
3800-Administrative and General Expenses Total	**1,237,175.00**
3850-Amortization Expense	
5705-Amortization Expense - Property, Plant, and Equipment	1,775,255.00
3850-Amortization Expense Total	**1,775,255.00**
3900-Interest Expense	
6005-Interest on Long Term Debt	-
6030-Interest on Debt to Associated Companies	631,663.00
6035-Other Interest Expense	19,000.00
6042-Allowance For Other Funds Used During Construction	
3900-Interest Expense Total	**650,663.00**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	10,300.00
3950-Taxes Other Than Income Taxes Total	**10,300.00**
4000-Income Taxes	
6110-Income Taxes	449,000.00
6115-Provision for Future Income Taxes	
4000-Income Taxes Total	**449,000.00**
4100-Extraordinary & Other Items	
6205-Donations	1,450.00
6215-Penalties	-
5706-Amortization Street Lighting	-
6310-Extraordinary Deductions	
4100-Extraordinary & Other Items Total	**1,450.00**
Net Income	**(755,200.98)**

APPENDIX A

COPY OF INNISFIL HYDRO 2009 PRO FORMA STATEMENTS

INNISFIL HYDRO
PRO FORMA FINANCIAL STATEMENTS
AT
DECEMBER 31 2009

2009 BALANCE SHEET

Account Description	Total
1050-Current Assets	
1005-Cash	-
1010-Cash Advances and Working Funds	1,550.00
1020-Interest Special Deposits	-
1040-Other Special Deposits	170,000.00
1070-Current Investment	343,000.00
1100-Customer Accounts Receivable	2,116,700.00
1102-Accounts Receivable - Services	-
1104-Accounts Receivable - Recoverable Work	235,000.00
1105-Accounts Receivable - Merchandise, Jobbing, etc.	-
1110-Other Accounts Receivable	239,000.00
1120-Accrued Utility Revenues	2,500,000.00
1130-Accumulated Provision for Uncollectible Accounts--Credit	(201,700.00)
1140-Interest and Dividends Receivable	-
1150-Rents Receivable	56,000.00
1180-Prepayments	220,000.00
1200-Accounts Receivable from Associated Companies	-
1210-Notes Receivable from Associated Companies	-
1050-Current Assets Total	**5,679,550.00**

Account Description	Total
1100-Inventory	
1330-Plant Materials and Operating Supplies	275,000.00
1305-Fuel Stock	-
1350-Other Materials and Supplies	-
1100-Inventory Total	**275,000.00**

Account Description	Total
1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	21,720.00
1410-Other Special or Collateral Funds	312,000.00
1460-Other Non-Current Assets	-
1150-Non-Current Assets Total	**333,720.00**

Account Description	Total
1200-Other Assets and Deferred Charges	
1508-Other Regulatory Assets	178,605.00
1518-RCVARetail	(19,286.00)
1525-Miscellaneous Deferred Debits	-
1548-RCVASTR	37,313.00
1550-LV Variance Account	252,940.00
1555-Smart Meters Capital Variance Account	17,393.00
1556-Smart Meters OM&A Variance Account	-
1562-Deferred Payments in Lieu of Taxes	(726,321.00)
1563-Deferred Payments in Lieu of Taxes contra	726,321.00
1565-Conservation and Demand Management Expenditures and Recoveries	-
1566-CDM Contra Account	-
1570-Qualifying Transition Costs	-
1571-Pre-market Opening Energy Variance	-
1572-Extraordinary Event Costs	-
1580-RSVAWMS	(340,465.00)
1582-RSVAONE-TIME	69,800.00
1584-RSVANW	(295,100.00)
1586-RSVACN	462,418.00
1588-RSVAPOWER	507,341.00
1590-Recovery of Regulatory Asset Balances	46,499.00
1200-Other Assets and Deferred Charges Total	**917,458.00**

1450-Distribution Plant	
1805-Land	283,350.00
1806-Land Rights	-
1808-Buildings and Fixtures	-
1810-Leasehold Improvements	86,252.00
1815-Transformer Station Equipment - Normally Primary above 50 kV	
1820-Distribution Station Equipment - Normally Primary below 50 kV	4,553,983.93
1825-Storage Battery Equipment	-
1830-Poles, Towers and Fixtures	8,678,712.85
1835-Overhead Conductors and Devices	12,495,611.14
1840-Underground Conduit	1,791,346.86
1845-Underground Conductors and Devices	7,578,038.92
1850-Line Transformers	8,547,584.66
1855-Services	3,759,562.93
1860-Meters	1,831,655.59
1450-Distribution Plant Total	**49,606,098.88**

1500-General Plant	
1905-Land	201,049.00
1906-Land Rights	993,027.03
1908-Buildings and Fixtures	717,361.76
1915-Office Furniture and Equipment	281,994.69
1920-Computer Equipment - Hardware	863,802.62
1925-Computer Software	972,829.85
1930-Transportation Equipment	357,580.38
1935-Stores Equipment	23,173.73
1940-Tools, Shop and Garage Equipment	168,136.44
1945-Measurement and Testing Equipment	25,102.25
1950-Power Operated Equipment	-
1955-Communication Equipment	-
1960-Miscellaneous Equipment	-
1970-Load Management Controls - Customer Premises	-
1980-System Supervisory Equipment	1,359,315.41
1995-Contributions and Grants - Credit	(5,391,730.80)
1500-General Plant Total	**571,642.36**

1550-Other Capital Assets	
2055-Construction Work in Progress--Electric	-
2060-Electric Plant Acquisition Adjustment	-
2070-Other Utility Plant	-
1875-Street Lighting	44,283.00
1550-Other Capital Assets Total	**44,283.00**

1600-Accumulated Amortization	
2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(26,972,673.50)
2160-Accumulated Amortization of Other Utility Plant	-
1600-Accumulated Amortization Total	**(26,972,673.50)**

Total Assets	**30,455,078.74**

1650-Current Liabilities	
2205-Accounts Payable	78,000.00
2208-Customer Credit Balances	282,000.00
2210-Current Portion of Customer Deposits	238,000.00
2220-Miscellaneous Current and Accrued Liabilities	777,700.00
2225-Loans payable	1,265,915.67
2240-Accounts Payable to Associated Companies	-
2250-Debt Retirement Charges(DRC) Payable	143,000.00
2252-Transmission Charges Payable	531,000.00
2256-IESO Payable	1,622,100.00
2260-Current portion of Long Term Debt	2,941,777.00
2268-Accrued interest on LTD	144,996.00
2290-Commodity Taxes	192,000.00
2292-Payroll Deductions / Expenses Payable	1,200.00
2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	450,000.00
2296-Future Income Taxes - Current	-
1650-Current Liabilities Total	**8,667,688.67**

1700-Non-Current Liabilities	
2306-Employee Future Benefits	-
2310-Vested Sick Leave Liability	
2320-Other Miscellaneous Non-Current Liabilities	-
2335-Long Term Customer Deposits	467,000.00
2340-Collateral funds liability	33,000.00
2350-Future Income Tax - Non-Current	-
2405-Other Regulatory Liabilities	-
2425-Other Deferred Credits	-
1700-Non-Current Liabilities Total	**500,000.00**

1800-Long-Term Debt	
2525-Term Bank Loans - Long term portion	3,702,199.60
2550-Advances from Associated Companies	4,382,000.00
1800-Long-Term Debt Total	**8,084,199.60**

1850-Shareholders' Equity	
3005-Common Shares Issued	10,852,444.00
3010-Contributed Surplus	-
3022-Development charges transferred	555,619.94
3030-Miscellaneous Paid-In Capital	-
3045-Unappropriated Retained Earnings	2,129,441.00
3046-Balance Transferred From Income	290,685.53
3049-Dividends Payable-Common Shares	(625,000.00)
1850-Shareholders' Equity Total	**13,203,190.47**

Total Liabilities & Shareholder's Equity	**30,455,078.74**

Balance Sheet Total	(0.00)

2009 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(8,801,999.00)
4010-Commercial Energy Sales	-
4015-Industrial Energy Sales	-
4020-Energy Sales to Large Users	-
4025-Street Lighting Energy Sales	(94,537.00)
4030-Sentinel Lighting Energy Sales	(7,066.00)
4035-General Energy Sales	(4,094,152.00)
4050-Revenue Adjustment	
4055-Energy Sales for Resale	-
4060-Interdepartmental Energy Sales	
4062-Billed WMS	(1,478,643.00)
4066-Billed NW	(1,223,657.00)
4068-Billed CN	(823,277.00)
4075-Billed LV	(497,129.00)
3000-Sales of Electricity Total	**(17,020,460.00)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(6,721,619.53)
4082-Retail Services Revenues	(24,909.00)
4084-Service Transaction Requests (STR) Revenues	(1,360.00)
4090-Electric Services Incidental to Energy Sales	
3050-Revenues From Services - Distirbution Total	**(6,747,888.53)**
3100-Other Operating Revenues	
4210-Rent from Electric Property	(145,208.00)
4220-Other Electric Revenues	
4225-Late Payment Charges	(89,542.00)
4230-Sales of Water and Water Power	
4235-Miscellaneous Service Revenues	(109,490.00)
3100-Other Operating Revenues Total	**(344,240.00)**
3150-Other Income & Deductions	
4325-Revenues from Merchandise, Jobbing, Etc.	-
4330-Costs and Expenses of Merchandising, Jobbing, Etc.	-
4355-Gain on Disposition of Utility and Other Property	-
4375-Revenue of Non-Utility Operations	(169,431.00)
4380-Expenses of Non-Utility Operations	169,431.00
4390-Miscellaneous Non-Operating Income	(7,053.00)
4398-Foreign Exchange Gains and Losses, Including Amortization	-
3150-Other Income & Deductions Total	**(7,053.00)**
3200-Investment Income	
4405-Interest and Dividend Income	(44,300.00)
3200-Investment Income Total	**(44,300.00)**
3350-Power Supply Expenses	
4705-Power Purchased	12,997,753.00
4708-Charges-WMS	1,240,153.00
4710-Cost of Power Adjustments	-
4714-Charges-NW	1,223,657.00
4715-System Control and Load Dispatching	
4716-Charges-CN	823,277.00
4730-Rural Rate Assistance Expense	238,491.00
4750-LV Charges	497,129.00
3350-Power Supply Expenses Total	**17,020,460.00**

3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	72,325.00
5010-Load Dispatching	6,050.00
5012-Station Buildings and Fixtures Expense	40,400.00
5014-Transformer Station Equipment - Operation Labour	-
5015-Transformer Station Equipment - Operation Supplies and Expenses	-
5016-Distribution Station Equipment - Operation Labour	7,400.00
5017-Distribution Station Equipment - Operation Supplies and Expenses	2,000.00
5020-Overhead Distribution Lines and Feeders - Operation Labour	40,850.00
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	36,600.00
5030-Overhead Subtransmission Feeders - Operation	3,250.00
5035-Overhead Distribution Transformers- Operation	3,650.00
5040-Underground Distribution Lines and Feeders - Operation Labour	27,000.00
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	8,950.00
5055-Underground Distribution Transformers - Operation	250.00
5065-Meter Expense	67,750.00
5070-Customer Premises - Operation Labour	47,200.00
5075-Customer Premises - Materials and Expenses	9,500.00
5085-Miscellaneous Distribution Expense	401,700.00
5095-Overhead Distribution Lines and Feeders - Rental Paid	3,700.00
5096-Other Rent	-
3500-Distribution Expenses - Operation Total	**778,575.00**

3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	11,950.00
5110-Maintenance of Buildings and Fixtures - Distribution Stations	-
5114-Maintenance of Distribution Station Equipment	39,300.00
5120-Maintenance of Poles, Towers and Fixtures	44,680.00
5125-Maintenance of Overhead Conductors and Devices	143,500.00
5130-Maintenance of Overhead Services	67,700.00
5135-Overhead Distribution Lines and Feeders - Right of Way	188,100.00
5145-Maintenance of Underground Conduit	-
5150-Maintenance of Underground Conductors and Devices	13,050.00
5155-Maintenance of Underground Services	64,550.00
5160-Maintenance of Line Transformers	50,250.00
5175-Maintenance of Meters	34,000.00
3550-Distribution Expenses - Maintenance Total	**657,080.00**

3650-Billing and Collecting	
5305-Supervision	44,900.00
5310-Meter Reading Expense	153,200.00
5315-Customer Billing	383,950.00
5320-Collecting	345,200.00
5330-Collection Charges	50.00
5335-Bad Debt Expense	30,000.00
5340-Miscellaneous Customer Accounts Expenses	53,300.00
3650-Billing and Collecting Total	**1,010,600.00**

3700-Community Relations	
5405-Supervision	-
5410-Community Relations - Sundry	8,100.00
5415-Energy Conservation	-
5420-Community Safety Program	1,000.00
5425-Miscellaneous customer accounts expenses	2,600.00
5510-Demonstrating and Selling Expense	-
5515-Advertising Expense	-
5520-Miscellaneous Sales Expense	-
3700-Community Relations Total	**11,700.00**
3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	214,350.00
5610-Management Salaries and Expenses	165,525.00
5615-General Administrative Salaries and Expenses	519,170.00
5620-Office Supplies and Expenses	82,450.00
5625-Administrative Expense Transferred Credit	-
5630-Outside Services Employed	56,800.00
5635-Property Insurance	44,200.00
5640-Injuries and Damages	40,600.00
5645-Employee Pensions and Benefits	9,400.00
5655-Regulatory Expenses	90,690.00
5660-General Advertising Expenses	-
5665-Miscellaneous General Expenses	72,930.00
5670-Rent	350.00
5675-Maintenance of General Plant	150,600.00
5680-ESA Fees	16,100.00
3800-Administrative and General Expenses Total	**1,463,165.00**
3850-Amortization Expense	
5705-Amortization Expense - Property, Plant, and Equipment	1,980,834.00
3850-Amortization Expense Total	**1,980,834.00**
3900-Interest Expense	
6005-Interest on Long Term Debt	92,066.00
6030-Interest on Debt to Associated Companies	575,576.00
6035-Other Interest Expense	28,000.00
6042-Allowance For Other Funds Used During Construction	
3900-Interest Expense Total	**695,642.00**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	10,600.00
3950-Taxes Other Than Income Taxes Total	**10,600.00**
4000-Income Taxes	
6110-Income Taxes	243,000.00
6115-Provision for Future Income Taxes	
4000-Income Taxes Total	**243,000.00**
4100-Extraordinary & Other Items	
6205-Donations	1,600.00
6215-Penalties	-
5706-Amortization Street Lighting	-
6310-Extraordinary Deductions	
4100-Extraordinary & Other Items Total	**1,600.00**
Net Income	**(290,685.53)**

RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND FINANCIAL RESULTS FILED:

Innisfil Hydro advises the 2006 and 2007 Audited Financial Statements do not vary from the regulatory financial results filed in this Application.

PROPOSED ACCOUNTING TREATMENT FOR PROJECTS WITH A PROJECT LIFE CYCLE GREATER THAN ONE YEAR:

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

INFORMATION ON PARENT AND SUBSIDIARIES

Innisfil Hydro is 100% owned by the Town of Innisfil. Innisfil Hydro has no subsidiaries.

RATE BASE:

Rate Base Overview:

The rate base used for the purpose of calculating the revenue requirement used in this Application follows the definition used in the 2006 EDR Handbook as an average of the balances at the beginning and the end of the 2009 Test Year, plus a working capital allowance, which is 15% of the sum of the cost of power and controllable expenses.

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

Innisfil Hydro has provided its rate base calculations for the years 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Bridge Year and 2009 Test Year in Table 1 below. Innisfil Hydro has calculated its 2009 rate base as $24,089,366.

Table 1
Summary of Rate Base

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Bridge Year	2009 Test Year
Gross Fixed Assets	35,058,164	38,960,919	40,409,084	43,766,331	50,177,741
Accumulated Depreciation	(18,087,071)	21,759,867	23,388,379	25,078,321	26,972,674
Net Book Value	16,971,093	17,201,051	17,020,706	18,688,011	23,205,068
Average Net Book Value	16,971,093	16,744,214	17,110,879	17,854,358	20,946,539
Working Capital	17,517,503	19,713,485	19,869,862	20,389,846	20,952,180
Working Capital Allowance	2,627,625	2,957,023	2,980,479	3,058,477	3,142,827
Rate Base	19,598,718	19,701,236	20,091,358	20,912,835	24,089,366

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

Table 2
Summary of Working Capital

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Bridge Year	2009 Test Year
Cost of Power	14,524,264	16,807,414	16,686,544	16,867,021	17,020,460
Operations	494,922	600,374	639,277	733,700	778,575
Maintenance	452,465	416,921	489,578	580,100	657,080
Billing & Collecting	808,786	829,594	923,175	950,950	1,010,600
Community Relations	8,290	60,213	49,890	10,600	11,700
Administration & General Expense	1,216,272	989,218	1,071,420	1,237,175	1,463,165
Property Taxes	12,504	9,751	9,979	10,300	10,600
Working Capital	17,517,503	19,713,485	19,869,862	20,389,846	20,952,180

Innisfil Hydro Distribution System:

Innisfil Hydro owns and operates the electricity distribution system in its licensed service area in the Town of Innisfil, serving approximately 16,900 Residential, General Service, Street Lighting, Sentinel Lighting and Unmetered Scattered Load customers/connections.

Innisfil Hydro is supplied through the Hydro One distribution system at Voltages of 8.3 kV and 44 kV. Electricity is then distributed through Innisfil Hydro's service area of 292 square kilometres over 116 kilometres of underground cable and 521 kilometres of overhead cable and 10,000 poles. Innisfil Hydro not only delivers electricity at its supply Voltage but also owns 9 distribution stations stepping Voltage down to 27.6 kV & 8.3 kV. Voltage is further stepped down in order to supply individual customers through approximately 3,100 transformers.

Innisfil Hydro monitors its distribution system through one control centre. The control centre operates the Supervisory Control and Data Acquisition ("SCADA") systems twenty-four hours a day, seven days a week by on call management staff.

Innisfil Hydro owns and maintains approximately 14,200 meters installed on its customers' premises for the purpose of measuring consumption of electricity for billing purposes. Meters vary in type by customer and include meters capable of measuring kWh consumption, kW and kVA demand as well as hourly interval data. Innisfil Hydro is also actively working towards planning and installation of smart meters as part of the Province of Ontario's smart meter initiative. These meters are capable of measuring the quantity and time of day (time-of-use) that the customer uses electricity. Innisfil Hydro will have all of its meters converted to smart meters by the end of 2010.

In managing its distribution system assets, Innisfil Hydro's main objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, safety, and customer service requirements. Accompanying this Schedule as Appendix A is a copy of Innisfil Hydro's "Asset Management Plan" document (referred to as the "AMP"), which sets out Innisfil Hydro's processes for determining the necessary distribution system investments to ensure safe, reliable delivery of electricity to its customers.

Innisfil Hydro considers performance-related asset information including, but not limited to, data on reliability, asset age and condition, loading, customer connection requirements, and system configuration, to determine investment needs of the system.

In addition to the capital needs of the network, Innisfil Hydro provides for maintenance planning for the assets. Innisfil Hydro maintenance practices and programs are addressed in the AMP, and are discussed in Exhibit 4, Tab 1, Schedule 1.

Innisfil Hydro assets fall into two broad categories – distribution plant, which includes assets such as wires, overhead and underground electricity distribution infrastructure, transformers, meters and substations; and general plant, which includes assets such as buildings, computer hardware and software, office furniture and equipment, transportation equipment, communications equipment and tools. Detailed lists of distribution and general plant categories by OEB account can be found in the Gross Assets Table at Exhibit 2, Tab 2, Schedule 2.

Distribution Plant Capital Projects:

The distribution plant capital projects are categorized into project pools. Each pool has a specific focus:

- **Customer Demand:**

These are projects that Innisfil Hydro undertakes to meet its customer service obligations in accordance with the OEB's Distribution System Code (the "DSC") and Innisfil Hydro's Conditions of Service. Activities include all overhead and underground works to connect new customers or service upgrades, connection and inspection of new subdivisions and relocating system plant for roadway reconstruction work. Capital contributions toward the cost of these projects are collected by Innisfil Hydro in accordance with the DSC and the provisions of its Conditions of Service. Innisfil Hydro uses the economic evaluation methodology from the DSC to determine the level of capital contribution for each subdivision project.

- **Infrastructure Replacement and Betterments:**

Projects are completed when assets reach their end of useful life and must be replaced. Innisfil Hydro completes visual inspections of its plant and performs predictive testing on certain assets where such testing is available, and replaces assets based on these inspection and testing activities if warranted. In some cases the projects involve spot replacement of assets; in others, the projects involve complete asset replacement within a geographic area. When a geographic area is being replaced, consideration is given to converting the distribution Voltage from 8.32 kV to higher Voltage level of 27.6kV given the available geography and boundary. Converting Voltage levels while replacing the assets does not increase the cost of the project but delivers added benefits including reductions in substation maintenance, capital expenditures and reduced system losses. New assets require less maintenance, deliver better reliability and reduce safety risks to the general public.

- **Security:**

There are some areas of the distribution system where failure of equipment may cause large outages, which cannot be restored through switching to alternate supplies. The probability and impact of asset failure are considered at peak load to determine the risk the failure creates. In these cases, projects are developed to add switching devices or create a backup feeder supply to reduce the risk to typical restoration times for Innisfil Hydro and its surround utilities.

- **Capacity:**

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

- **Reliability and System Automation:**

The main driver for these investments is an analysis of what measures could be undertaken to improve Innisfil Hydro reliability performance as measured by SAIDI, SAIFI and CAIDI indices. These indices are indicators of the reliability of Innisfil Hydro's distribution system. These activities will support maintenance of, or improvement to, the Service Quality Indices measured and submitted to the OEB each year.

- **Regulatory Requirements:**

These projects are system capital investments which are being driven by regulatory requirements. These may include, among others, directions from the OEB, the IESO, the Ministry of Energy or the Ministry of Environment. For 2008 and 2009, Innisfil Hydro anticipates that projects in this category will relate to the elimination of long-term load transfers and the expansion of distribution generation assets pursuant to the DSC.

- **Substations:**

Substation investments are undertaken to improve or maintain reliability to large numbers of customers and to maintain security and safety at the substations.

- **Customer Connections and Metering:**

Capital expenditures in this pool include meter installations and upgrades, capital components of wholesale and retail meter verification activities.

General Plant Capital Projects

Other Computer Hardware and Software

- **Computer Hardware:**

Computer equipment is used in all departments of utility operations and is a key enabler Innisfil Hydro initiative to maintain and improve reliability, improve customer service and reduce costs.

New and replacement Computer hardware consists of the following equipment:

- Desktops;
- Laptops;
- Servers;
- Printers;
- Disk space and memory

Innisfil Hydro utilizes a three to four year life cycle for its server hardware and a four to five year life cycle for its workstation hardware. Software is reviewed and analyzed as updates are provided by the developers. It is common industry practice to keep both the hardware and software environments up to date. Increased incidence of hardware failure reduced technical support, new technical standards and higher performance requirements of current operating systems and applications drive this lifecycle. The upgrade of aging servers and consolidation of multiple servers to a more manageable volume provide cost effective migration of workload with higher performance efficiencies and lower maintenance costs.

Other benefits of replacing computer equipment and adding new equipment include:

- Reducing the dependence on IT resources to support older equipment;
- Taking advantage of new technologies and increasing server utilization;
- Empowering employees to be more productive with the right equipment to do their jobs;
- Improving access to data and other information;
- Adhering to best practices; and
- Allowing for growth

- **Computer Software:**

Computer software, whether operating system software or application software, are programs written in machine-readable languages, that control the operations of hardware or that enable users to perform certain tasks on computers.

The operating system software controls the hardware and manages its internal functions: controls input, output and storage and, handles its interaction with application programs. Application software enables users to accomplish particular tasks.

Today, the functioning of computer software is tied closely into the hardware it resides on and it is important that the specification of any PC or Server is appropriate for the software being installed.

Benefits of adding or replacing computer software include:

- Improvements in productivity from software enhancements;
- Empowering employees with the latest software technologies;
- Keeping up to date with industry standards;
- Ease of integration to other applications;
- Reduced costs using common operating system;
- Taking advantage of higher levels of security;
- Reduced dependence on IT resources; and
- Improved tools for web development/design

Transportation and Related Equipment

This project is justified based on the need to maintain vehicles and major equipment functionality and provide safe, reliable tools and equipment.

Innisfil Hydro's practice is to replace vehicles every ten years, subject to kilometers, usage and experience with respect to vehicle reliability.

Innisfil Hydro vehicle replacement process considers the following criteria:

- Vehicle operational condition (# of repairs and cost during the previous years);
- Vehicle safety;
- Mileage & age;
- Department needs; and
- Replacement of vehicles before they become costly to repair, uneconomic and unsafe to operate.

Problems, deficient conditions and maintenance needs are monitored as part of the vehicle preventative maintenance program.

New vehicles support productivity through reduced fuel costs and lower maintenance costs; and increase environmental responsibility through fuel reduction and alternate fuel usage.

Vehicle replacement supports a safe working environment and maintains productivity.

The 2009 budget provides for the acquisition of two new vehicles, to support the construction and maintenance of the electricity distribution system for Innisfil Hydro. The vehicles are replacing two older vehicles that have reached the end of the useful lives.

Communications Equipment

This project pool includes capital expenditures pertaining to the purchase of Innisfil Hydro's SCADA system, including programming modifications, design and enhancements.

Tools and Equipment

The timely replacement of tools and equipment that are worn, or have come to the end of their useful life, with newer and more ergonomically friendly tools and equipment supports a safe work environment for Innisfil Hydro employees.

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

Innisfil Hydro has provided a project-specific justification in detail in Exhibit 2, Tab 3, Schedule 2 from 2005 to 2009 Test Year for capital projects having a cost greater than $170,000 (1% of Innisfil Hydro total net fixed assets, being the materiality threshold in the Filing Requirements) within the distribution and general plant categories discussed above. The rationales for capital projects are provided on a project specific basis. Innisfil Hydro is also providing detailed capital expenditures by USofA account from 2005 to 2009 Test year in Exhibit 2, Tab 3, Schedule 1.

In support of its rate base calculation, Innisfil Hydro has enclosed the information contemplated by the Filing Requirements:

- Continuity Schedules (Exhibit 2, Tab 2, Schedule 1);
- Gross Assets Table and Materiality Analysis (Exhibit 2, Tab 2, Schedules 2 and 3);
- Accumulated Depreciation Table and Materiality Analysis (Exhibit 2, Tab 2, Schedules 4 and 5);
- Working Capital (Exhibit 2, Tab 4, Schedule 1).

The 2008 Bridge and 2009 Test Years' gross asset balances reflect the capital expenditure programs forecast for both years. These programs are described in detail in Exhibit 2, Tab 3, Schedule 1. The justifications for capital projects in excess of 1% of total net fixed assets are also contained in Exhibit 2, Tab 3, Schedule 2.

Innisfil Hydro's Overall Budget Process

The annual and 5 year budget plan is prepared annually by management and is reviewed and approved by the Board of Directors. The budget is prepared before the start of each fiscal year. Once approved, it does not change, but provides a plan against which actual results may be measured and evaluated.

Responsibilities

- It is the responsibility of the Finance department to coordinate the development of the operating budget, capital budget and forecast processes.
- Each department is responsible for preparing its operating budget, capital budget, and rolling forecasts.
- The President is responsible for presenting and recommending the budget to the Board of Directors for approval.
- It is the responsibility of the Board of Directors, on behalf of the shareholders, to approve the budget.

The budget is an important planning tool for Innisfil Hydro. It puts capital and operational plans into a common financial plan. The final document provides a comprehensive package of department budgets that collectively ensure that appropriate resources are designated for the various capital and operational needs of the utility for the coming year. The departmental Budget Plans represent the output of detailed work plans based on required activities for the year. The Budget Plans address both capital and operating requirements.

Budget Review Process

Innisfil Hydro budget review process is as follows:

- Each department budget is reviewed and approved by the corresponding Director and submitted to the Finance department.
- The Finance department consolidates all departmental work plan budgets to produce budget reports by functional areas to be reviewed by the Executive Team members.

- The Executive Team members will then have an opportunity to make recommendations to the consolidated budgets.
- A final budget package is produced for final review and approval by the Executive Team.

The Actual-to-Budget Review Process

Once the budget is final, each department reviews and tracks progress against the budget on a monthly basis. Further, quarterly reviews and forecasts of actual and/or expected results against the budget are performed during the budget year. This review process involves the following activities:

- All Directors/Managers review the year-to-date ("YTD") operating results for their area(s) of responsibility on a monthly basis.
- Significant variances in capital and operating expenditures based on YTD results are reviewed along with work plans in order to identify any changes that may have an impact on the forecast of actual expenditures.
- Any significant and/or material expenditures/savings that will affect the current year's operating results are incorporated into the actual-to-budget forecast. All expenditures in excess of the budget and all savings are reported. An initial draft of the forecast is prepared based on the information provided and a review of significant variances/changes is conducted with each Manager/Director to create the forecast.
- The Executive Team reviews the forecast and provides feedback, comments and adjustments before the forecast is finalized.
- The President approves the final forecast for presentation to the Board of Directors.

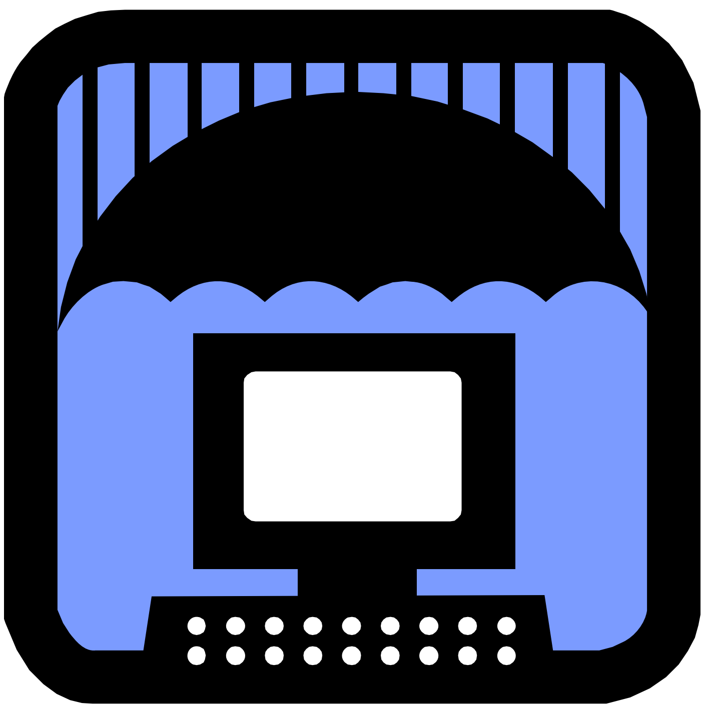
APPENDIX A

INNISFIL HYDRO'S ASSET MANAGEMENT PLAN

Innisfil Hydro Distribution Systems Limited

Asset Management Plan

August 2008



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Background

The Innisfil Hydro Electric Commission was originally formed in 1993 via the purchase of distribution assets from Ontario Hydro. Innisfil Hydro Distribution Systems Limited (Innisfil Hydro) was incorporated as a for-profit local distribution company in year 2000 as required by the *Electricity Act 1998*. Innisfil Hydro has a distribution licence from the Ontario Energy Board (Licence # ED-2002-0520) to operate its distribution system within the licensed territory of 292 square kilometres within the Town of Innisfil Ontario.

As of January 1, 2008, Innisfil Hydro had approximately 110 kilometres of 44KV circuits, 176 kilometres of three-phase distribution, 200 kilometres of single-phase circuits, 116 kilometres of primary underground cable, 9 distribution stations, 2 shared distribution stations with Hydro One and 4 private stations with distribution voltages of 16/27.6kv and 4.8/8.32kv.

Innisfil Hydro does not have any "in-house" Linemen or Substation personnel. All associate Line and Substation work is contracted out to an independent contractor.

The Head Office and Operations Centre for Innisfil Hydro is located at 2073 Commerce Park Drive in Innisfil Ontario with 22 full time staff. The site consists of a Customer Service building, an Engineering and finance Building and a Warehouse building situated on approximately four acres.

Following the aftermath of the Oak Ridges Moraine Act, property developers have acquired many Innisfil properties for the purpose of land development. Land development pressures have been reflected in the Town of Innisfil's Official Plan (2006);

http://www.innisfil.ca/Business/NEW_officialplan.php?ID=127&CID=138

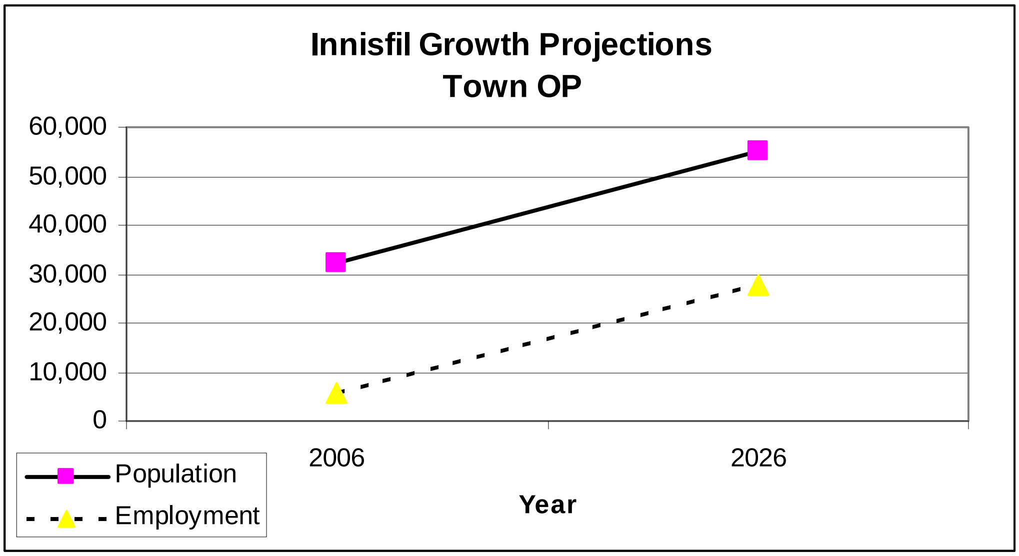
and in the County of Simcoe Proposed Official Plan (2008);

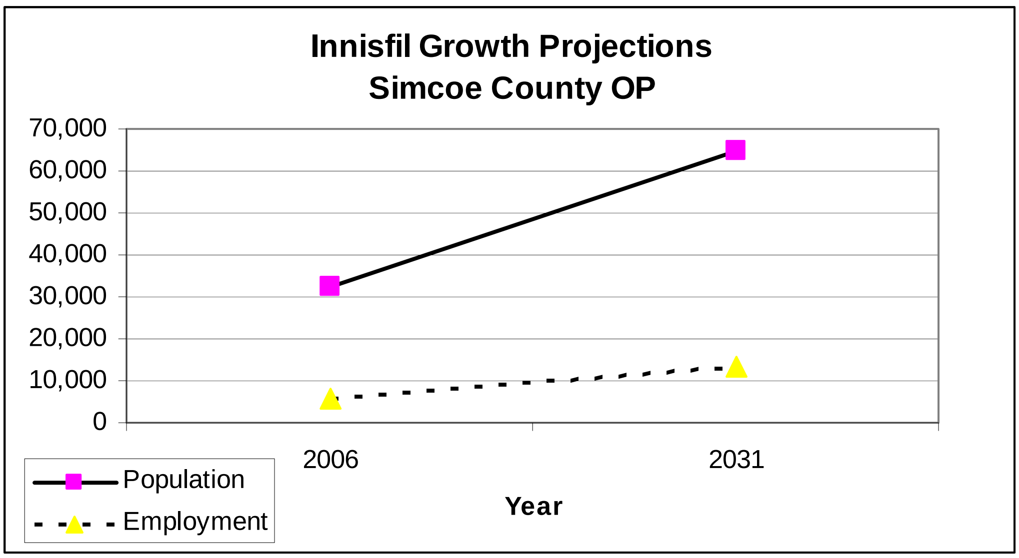
http://www.simcoe.ca/municipalservices/planning/policyplanning/wscos_002389

The Town of Innisfil Official Plan (2006) and the County of Simcoe Proposed Official Plan (2008) growth projections have been summarized below:

Official Plan	Population 2006	Population 2026	Employment 2006	Employment 2026
Innisfil	32,400	55,000	5,700	27,700

Official Plan	Population 2006	Population 2031	Employment 2006	Employment 2031
Simcoe	32,400	65,000	5,700	13,100





In the past six years, capital growth requirements have been slow and in 2007, even negative. This reflects the maturing development of the distribution system in Innisfil. Both population and employment is projected to increase by more than 100% within the next 25 years. It is this municipal growth that is fueling the need for capital expansion within this rate application. As required in the Distribution System Code:

6.1.1 A distributor shall make every reasonable effort to respond promptly to a customer's request for connection. In any event a distributor shall respond to a customer's written request for a customer connection within 15 calendar days. A distributor shall make an offer to connect within 60 calendar days of receipt of the written request, unless other necessary information is required from the load customer before the offer can be made.

The capital infrastructure necessary to more than double existing demand requires long term planning where capital infrastructure is staged. Failure to approve planned capital requirements will prohibit the ability for Innisfil Hydro to meet the needs of the growing community and therefore growth would restricted due to lack of capacity, contrary to the Distribution System Code.

*** This Asset Management Plan is a 'living document' and will receive on-going review.**

2.0 Regulatory Requirements

The Distribution System Code (DSC) requires an LDC to maintain its distribution system in good working condition, as follows:

"4.4.1 A distributor shall maintain its distribution system in accordance with good utility practice and performance standards to ensure reliability and quality of electricity service, on both a short-term and long-term basis."

The DSC has an ***Appendix C, Minimum Maintenance Standards***. Appendix C, as amended from time to time, will be attached to and will be a part of this plan.

Furthermore, introduction of Ontario Regulation 22/04, Electrical Distribution Safety, in late 2004 introduced additional legislated focus on maintaining municipal distribution systems. Specifically the Regulation requires an LDC to:

" Section 4. Safety standards…

(2) All distribution systems and the electrical installations and electrical equipment forming part of such systems shall be designed, constructed, installed, protected, used, maintained, repaired, extended, connected and disconnected so as to reduce the probability of exposure to electrical safety hazards. O. Reg. 22/04, s. 4 (2)."

Section 4 goes on to identify all components of the distribution system and specifies for each component as follows:

" 1. Operating electrical equipment shall be maintained in proper operating condition."

IHDSL has established a documented program to address the legislated requirements to maintain its distribution system.

Historical and present electrical system maintenance does not meet the all of the minimum maintenance standards in DSC Appendix C.   Any reduction in Operations or Maintenance funding will further erode Innisfil Hydro's ability in achieving all of the maintenance requirements in the DSC.

3.0 Overhead Lines

3.1 Tree Trimming

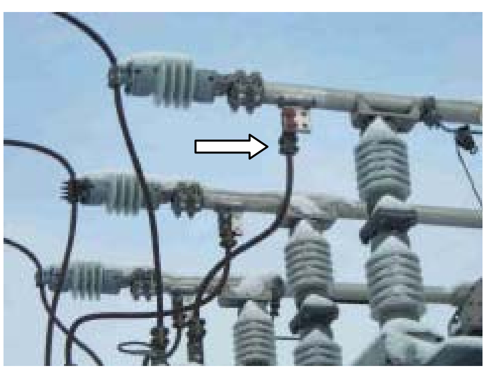
Vegetation and Right of Way control is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Innisfil Hydro has a large rural and urban area where overhead hydro lines are in the proximity to trees. Trees contacting energized lines have the ability to inflict the following:

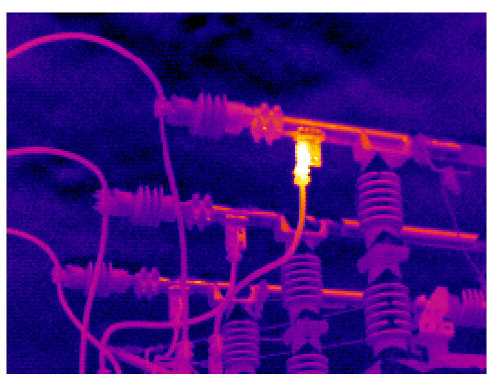
- Interruption of power due to short circuit to ground or between phases
- Damage to conductors, hardware and poles
- Danger to persons and property within the vicinity due to falling conductors, hardware, poles and trees
- Danger of electric shock potential from electricity energizing vegetation

In an effort of mitigating direct contact between trees and distribution assets, tree trimming is conducted on a three year cycle. Innisfil Hydro does not have any 'in-house' tree trimming personnel or equipment and therefore uses an independent contractor at market rates. Depending on the size, shape and growth aspect of relevant trees, the tree trimmers remove sufficient foliage from the tree to limit the possibility of contact during high wind situations.

Following tree trimming, the independent contractor removes all debris and returns the site to as-found condition. Any pole line damage or anomaly noticed by the tree trimming crew is reported to Innisfil Hydro for remedial action. The 2009 cost for tree trimming has been budgeted in account 5135 totaling $188,100 which does include internal costs.

3.2 Infra-red Scanning





Electrical energy creates the movement of electrons through a conductor. In situations where a restriction in a conductor or an electrical connection exists, the movement of electrons through the restriction heats up. Left unabated, the effect of 'hot spots' can have the following effects:

- Increased line losses
- Radio interference
- Damage to equipment
- The danger of energized equipment falling to the ground
- Power interruption

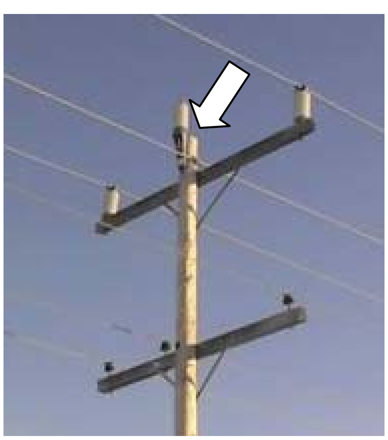
The attached picture indicates an infrared scan of a hot connection which would require immediate action. Innisfil Hydro does not have trained personnel nor has the equipment necessary for infra-red scanning. This service is contracted out to an independent contractor at market rates.

In an effort to be pro-active, infrared scanning is performed on Innisfil Hydro's assets in a three year cycle as follows:

1. All overhead primary voltage 3 phase and single phase lines (44kV, 27.6kV, 8.32kV) including Distribution Stations.
2. All 44kV overhead lines including Distribution Stations, ½ of (27.6 kV & 8.32kV) 3 phase overhead primary voltage lines and ½ of all underground primary voltage lines.
3. All 44kV overhead lines including Distribution Stations, the other ½ of (27.6 kV & 8.32kV) 3 phase overhead primary voltage lines and the other ½ of all underground primary voltage lines.

Any abnormal condition is reported to Innisfil Hydro for remedial action. Critical abnormalities are reported to Innisfil Hydro for immediate action. The 2009 cost for infra-red scanning has been budgeted in accounts 5020 & 5045 totaling $49,800. The resulting maintenance requirements estimated from the infra-red scanning program is in account 5125 totaling $143,500.

3.3 Line Patrol



Line patrol is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Line patrol may highlight problems or may identify conditions that warrant a more thorough or vigorous inspection or the need for specific maintenance. Visual inspection of major distribution system components identify problems and hazards such as leaning poles, damaged equipment enclosures and vandalism. The attached picture was taken as a result of line patrol. The centre 44 kV conductor is resting on the wooden cross arm. Left unabated, the conductor would burn through the cross arm and possibly cause the pole to catch fire. The 44 kV circuit would lock-out affecting thousands of customers and possibly contact the lower circuit, affecting hundreds of customers with power interruption and possible electrical damage to their homes and businesses. Line patrol in this situation had the potential of saving thousands of customer interruption hours, saving several thousand dollars in asset replacement and the diversion of hundreds of insurance claims.

Line patrol includes a visual inspection of all related equipment as follows:

Conductors and Cables

- Low conductor clearance
- Broken/frayed conductors or tie wires
- Tree conditions, exposed broken ground conductors
- Broken strands, bird caging, and excessive or inadequate sag
- Insulation fraying on secondary especially open wire

Poles/Supports

- Bent, cracked or broken poles
- Excessive surface wear or scaling
- Loose, cracked or broken cross arms and brackets
- Woodpecker or insect damage, bird nests
- Loose or unattached guy wires or stubs
- Guy strain insulators pulled apart or broken
- Guy guards out of position or missing
- Grading changes, or washouts
- Indications of burning

Hardware and Attachments

- Loose or missing hardware
- Insulators unattached from pins
- Conductor unattached from insulators
- Insulators flashed over or obviously contaminated
- Tie wires unraveled
- Ground wire broken or removed
- Ground wire guards removed or broken

Vegetation and Right of Way

- Leaning or broken “danger” trees
- Growth into line of “climbing” plants
- Unapproved/unsafe occupation or secondary use

Civil Infrastructure

- Buildings that house equipment that need attention
- Cable chambers, underground vaults and tunnels that need attention

Contract line personnel and engineering staff perform line patrol whenever driving through Innisfil Hydro's distribution territory. Distribution system problems are either remedied immediately or scheduled for remedial action. Line patrol is also performed by Contract line personnel and engineering staff when a problem has been identified within a circuit by SCADA and or by customer calls.

During routine patrols through Innisfil, many trouble calls are identified each year. Reasons ranging from tree limbs to failing parts and materials are repaired as emergency calls at any time of day or night.

Pole top maintenance and pole inspection is a program where line staff stop and inspect each pole in a defined route by setting up a Line truck to tighten and inspect all hardware (insulators, cross-arms, bolts, etc.) Over time, wood poles shrink, wear and deteriorate to a point that original installations are loosened off. With weather elements such as wind and ice loading, hardware can eventually completely loosen and fail. The solution for this is on a yearly basis, a defined route of approximately one eighth of all poles (approximately 1250), would be inspected from a Line truck and all hardware tightened. The cost to do these works is approximately $78,000.00 and has not been budgeted for in 2009. To date, $5,000 to $7,000 per year are being spent for patrol inspections and service is also done on an as needed basis when identified by a trouble call. By staying proactive with this program the aim is to lower the SAIDI/SAIFI/CAIDI reporting and lower emergency calls where expense dollars are currently being drawn from.

Innisfil Hydro does not have any Operation's staff on duty 24/7. Engineering and Operation's staff perform line patrol while driving to and from work on a daily basis. The Town is divided into five quadrants and staff keep a log of the quadrants and dates that receive line patrol. The 2009 cost for line patrol is built into Operations accounts 5020 & 5045 totaling $49,800 for staff and vehicles.

3.4 Poles

Pole inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Innisfil Hydro utilizes approximately 10,000 poles within its distribution system incorporating Jack Pine, Red Pine, Western Red Cedar and Yellow Cedar ranging from 30' to 90'. These pole species involve creosote, chromium copper arsenate or pentachlorophenol treatment to extend the life of the wood. There are no concrete, steel or composite poles that are in service in Innisfil. The majority of wood deterioration occurs at the pole butt, basically where the pole enters the ground. The amount of pole below the surface is 2 feet plus 10% of the pole height. It is the area flush with the ground that receives the greatest impact of moisture and oxygen that enables the rotting of the pole which occurs from the inside-out. Poles are therefore tested to see the extent by which that they are hollow. The extent to which the pole is structurally sound correlates to the pole's ability to withstand structural loadings such as transformers, switches, hardware and wind sheer. Depending on the circumstances, poles that lack structural integrity have the risk of falling down and be injurious to property, personnel, equipment and the public.

Innisfil Hydro embarks on an eight year pole testing program cycle. The poles are tested using non-destructive devices that measure the moisture content of the wood just above ground level. The higher the moisture level within the wood relates to a higher level of deterioration. When a threshold level of moisture is detected, a resistograph is used to physically measure the extent of the deterioration. The pole testing results are logged and replacement is scheduled as required. Historically, a pole replacement rate of 4% has been experienced and is budgeted for within the capital budget.

Along with the pole testing results, the poles are numbered, tagged with a GPS coordinate and tagged with other hardware and nomenclature. The results are inputted into the Graphical Information System (GIS). An increase to a six year pole testing program cycle will increase pole testing costs by over 33%. The 2009 cost for pole testing utilizing an eight year pole testing program cycle has been budgeted in account 5120 totaling $44,680.

Each year in Innisfil at least 10 complaint calls are received from customers for leaning poles. These are existing poles in Innisfil that over time have leaned due to weather or soil conditions. Whether on a rural or urban road it, is becoming more noticeable that the existing poles are leaning more with each passing year. Presently, Innisfil Hydro uses a small amount of expense budget out of the 5120 account to deal with this issue, however the small amount of money available for this problem is not nearly enough to combat the larger picture outside of a few complaints.

A better initiative is a yearly program to straiten poles that are currently leaning. This issue will always be present with existing poles. In 2007, with 2 days of record breaking winds over 100km an hour, 6 double circuit 44000 volt sub-transmission poles that supply over 2/3 of the customers in Innisfil were straitened. The detrimental effect of leaning poles is that, once over center to a varying degree dependant on soil conditions, the pole has a much higher potential to be pushed over or break in storm winds or ice loading conditions. A domino effect can then occur toppling pole after pole. Aside from the fact that leaning poles are astatically displeasing to look at, the potential for more dangerous situations exist. Moving forward a budget figure of $35,000 dollars would accommodate the straitening of only 50 poles, but would constitute the start of an ongoing program year over year to deal with the problem. This amount has not been budgeted for in 2009.

Pole Replacements are undertaken for the following different reasons:

- Pole rotten or suffering from structural damage
- Vehicle accidents
- Customer service requests requiring taller or different class of pole
- Road widenings and grade changes
- Line rebuilds
- ESA compliance

Innisfil Hydro replaces poles that can exhibit a health and safety hazard to the public and staff. Each year, 1/8th of Innisfil Hydro wood poles are tested and rated to determine when they should be replaced or retested. Poles have been identified as needing a subsequent retest may undergo 'butt treatment' whereby the useful life of the pole can be extended.

In 2006, Innisfil Hydro spent $183k replacing 65 poles that were identified in the pole testing program. Poles are replaced to current ESA standards. With a 4% replacement program of the poles that are tested annually, the following number of poles are anticipated to be replaced each year over the next 5 years which includes pole replacements triggered by accidents and capital growth requirements:

	2008	2009	2010	2011	2012	2013
Total Count	10,000	10,120	10,150	10,180	10,210	10,250
Tot Replacement	400	300	310	310	315	315
Additional	120	30	30	30	30	30

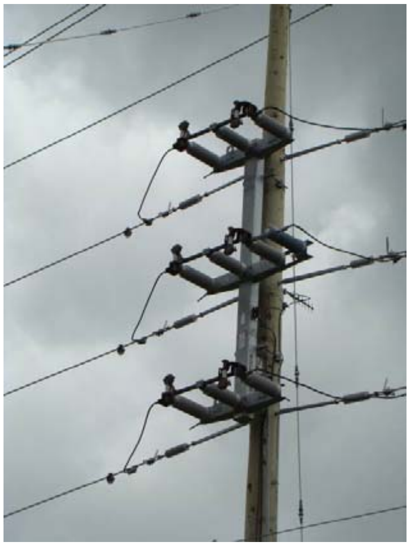
Failure to replace poles as required jeopardizes the health and safety of the public, system reliability and the ability to connect new customers due to restrictive policies of ESA.

3.5 Switches

Switch inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Switches are devices that allow or

disallow the conductivity of high voltage conductors. They are available in single phase solid or fused configurations and three phase applications involving load break (remote and local operation), and air break (remote and local operation).

Fused cut-outs accept different sizes of fuses, which are used for the protection of lines, equipment or transformers from main feeder amperages. There are 235 single phase and 42 three phase fused cutout



switches in Innisfil Hydro’s distribution system.   Fused switches (cutouts) are inspected during the infra-red scanning process. Fused cutouts that fail are replaced as needed. When fused cut-outs fail with an abnormal frequency, fused cutout statistics are investigated to see if a manufacture’s defect has occurred. If a manufacturer’s defect is suspected, then all affected fused cutouts may be replaced as an act of due diligence. Failure to do so will not only decrease reliability, the safety of operational personnel would be compromised.

There are 34 three phase airbreak switches and 19 three phase loadbreak switches in Innisfil Hydro’s distribution system. These switches are predominately on the 44kV system and perform switching operations to allow for maintenance and emergency procedures. Along with inspections carried out by infra-red scanning, these switches have scheduled maintenance once every four years. Line staff therefore perform switch maintenance on ¼ of all airbreak and loadbreak switches on an annual basis. The cost projected to perform three phase switch maintenance for 2009 has been budgeted in account 5125 totaling $143,500 which does not include repair parts.

There are 302 in-line switches and 30 MSOs on the 44kV, 27.6kV and 8.32kV system. These are single phase switches or mid span openers that can be grouped together in a three phase feeder. These switches are used for sectionalizing circuits for maintenance and emergency requirements. In-line switches can be used to break load when a load-break tool is used. In-line switches are inspected during the infra-red scanning process. In-line switches that fail are replaced as needed. Failure to do so will not only decrease reliability, the safety of operational personnel would be compromised. Switches are amortized over their useful life of 25 years. These devises have traditionally not received proactive maintenance. Requiring three crew hours to perform in-line switch or MSO maintenance on a four year schedule, then an extra $20,000 of contract labour would be required. This amount has not been budgeted for.

Switch Replacements are undertaken for the following different reasons:

- Mechanical or electrical failure
- Vehicle accidents, lightning strikes
- New customer requirements
- Road reconstruction
- Line rebuilds or circuit reconfigurations
- ESA compliance
- Upgrades for system security involving the SCADA system

The following switch addition and replacement schedule has been incorporated to deal with capital requirements:

Fused Cutouts Single & Three Phase

	2008	2009	2010	2011	2012	2013
Total Count	361	376	391	406	422	438
Replacement	9	100	100	10	10	10
Additional	15	15	15	16	16	16

Air Break and Load Break Three Phase Switches

	2008	2009	2010	2011	2012	2013
Total Count	53	54	60	63	66	69
Replacement	3	4	3	3	3	3
Additional	1	6	3	3	3	3

In-Line Switches & MSOs

	2008	2009	2010	2011	2012	2013
Total Count	332	332	317	311	305	299
Replacement	6	6	6	6	6	6
Additional	0	-15	-6	-6	-6	-6

3.6 Reclosures

Reclosure inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. There are 103 active oil reclosures in Innisfil Hydro's distribution system. These devises are programmable switches that open and close depending on how the current limits are set. These devises break load within an oil bath, for dielectric purposes. After a number of operations, the oil bath becomes contaminated with carbon, which is formed by the oxidation of the oil by the arc squelching process. The carbon impregnated oil looses dielectric properties and needs to be inspected and the oil replaced. The oil reclosurers are inspected and rebuilt once ever 4 years. They are also inspected by the infra-red process. Reclosurers that are damaged, will be replaced as required. Reclosures are amortized over their useful life of 25 years. The cost for rebuilding the reclosures is capitalized and the cost for maintaining reclosurers for 2009 is in account 5125 totaling $143,500.

3.7 Voltage Regulators

Voltage regulator inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice Voltage regulators are single phase devises that are situated on high voltage lines, far away from the Distribution Station. When line losses drop the voltage potential below acceptable levels, the voltage regulators increases the line voltage to within CSA standards. Innisfil has four voltage regulators in the distribution system. These devices are patrolled and inspected by the infra-red process. The devises are not physically removed from service for inspection. They are however visually inspected monthly. Voltage regulators are amortized over their useful life of 25 years. The 2009 cost for inspecting voltage regulators is in account 5016 totaling 7,400. There are no voltage regulators budgeted for replacement in 2009.

3.8 Transformers

Transformer inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Innisfil hydro has 3187 overhead and underground transformers in its distribution system. Transformers are able to turn high distribution voltage into low voltage (< 750V) that can be utilized by customers. All transformers have had their mineral oil tested and verified so that as of 2005, all transformers are PCB free (< 50 PPM). Transformers are visually inspected according to the Minimum Inspection Requirements in the Distribution system Code (every 3 years Urban and every 6 years rural). The typical line patrol inspections address the following issues:

- Hot connects via infra red scanning
- General appearance
- Loose wires
- Bird or animal nests

Innisfil Hydro has not proposed funding to engage in the following inspections as mentioned in the DSC:

- Paint condition and corrosion
- Phase indicators and unit numbers matching operating map
- Leaking oil
- Flashed or cracked insulators
- Condition of arrestor, fused cut-out, grounding & connections

For Innisfil Hydro to have contract staff either climb poles or set-up bucket trucks to inspect transformers up close, it is estimated that external contract costs of $86 per overhead transformer would be required. This translates into an annual cost increase of $52,000 for 1,355 rural and 904 urban overhead transformers. This has not been budgeted for in 2009.

Overhead transformers are amortized over their useful life of 25 years. The 2009 cost for inspecting transformers has been budgeted within the infra-red scanning process.

Transformers are changed with different sized units as needed. Transformers are replaced when they fail do to lightning strike, vehicle accident or internal/external problems. The following overhead transformer addition and replacement schedule has been incorporated to deal with capital requirements:

Overhead Transformers

	2008	2009	2010	2011	2012	2013
Total Count	2,259	2,269	2,279	2,289	2,300	2,311
Replacement	24	24	25	25	26	26
Additional	10	10	10	11	11	12

The 2009 cost for infra-red scanning overhead transformers has been budgeted in account 5020 & 5045 totaling $49,800.

3.9 Capacitors

Capacitor inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. When AC power flows through the conductor, there is a loss of power in the conductor due to its resistance and reactance. Capacitor banks are installed to reduce line losses, improve power factor and balance feeders for easier switching.

Innisfil Hydro has 9 sets of capacitor banks in its distribution system. Capacitors are visually inspected according to the Minimum Inspection Requirements in the Distribution System Code (every 3 years Urban and every 6 years rural) and are also inspected by the infra-red scanning program. Capacitors are inspected annually (basic inspection) and damaged capacitors are repaired or replaced as required. Capacitors are amortized over their useful life of 25 years. The 2009 cost for inspecting capacitors has been budgeted in account 5125 totaling $143,500. There are no plans to replace any capacitors with the next five year horizon.

3.10 Fault Indicators

The installation and use of radio controlled fault indicators has been deployed over the past few years. These units send radio signals to the Innisfil Hydro SCADA system when fault currents have traveled down a primary line. They assist in finding a problem section of line and for sectionalizing damaged sections of high voltage lines. Lowering SAIDI/SAIFI/CAIDI reporting is the root function of these indicators. Fault indicator inspection and testing is now required more urgently than in past years as Innisfil Hydro has been experiencing problems in communications via the radio system and also water infiltration into several of fault indicators themselves causing false reporting and failure of the units. A plan of testing and inspecting is a necessity to ensure good reporting with high reliability. With twenty two sets of indicators scattered over Innisfil Hydro territory an expected cost of $10,000 would be needed on a yearly basis to make this happen. This amount has not been budgeted for in 2009 or subsequent years.

3.11 Load Balancing

Due to the change in seasons through the year, distribution station loads fluctuate from electric heat loads in winter to air conditioning loads in summer. The addition of customer upgrades and new services going into the distribution system also contribute to unbalancing loads out of these stations. What the typical solution and remedy for this ongoing issue is to balance the distribution feeders out of the station. In doing so it accomplishes several things, the first of which is lowering line losses within the distribution system. It also increases the power factor of the station output and is operationally better for the life of the power transformer. To accomplish this goal, balancing is done at the onset of peak seasons (summer and winter) and would require $10,000 of crew labour to complete. This has not been budgeted for in 2009 or subsequent years.

4.0 Underground Lines

4.1 Switching Cubicles

Switching cubicle inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Innisfil Hydro has 40 switching cubicles in its distribution system. The manufacturer S&C has been the standard supplier for these devices (PME configuration). The function of these devices is to provide an above ground mechanism for underground express cables to be switched

and a connection for fused local cables. The PME standard utilizes a 'dead front' configuration where there are no high voltage conductors exposed when the switching cubicle doors are open. As opposed to the S&C PMH live front configuration, the PME's exhibit fewer problems and need less maintenance.

Switching cubicles are visually inspected according to the Minimum Inspection Requirements in the Distribution system Code (every 3 years Urban and every 6 years rural) and are also inspected by the infra-red scanning program every three years. Damaged switching cubicles are repaired or replaced as required. Switching cubicles are amortized over their useful life of 25 years. The 2009 cost for inspecting switching cubicles has been budgeted in account 5025 & 5045 totaling $49,800. There are no plans for capital replacements within the next five years.

4.2 Locates

As specified in section 228 the Occupational Health and Safety Act:

(1) Before an excavation is begun,

(a) gas, electric and other services in and near the area to be excavated shall be accurately located and marked; and
(b) if a service may pose a hazard, the service shall be shut off and disconnected.

(2) The employer who is responsible for the excavation shall request the owner of the service to locate and mark the service.

(3) If a service may pose a hazard and cannot be shut of or disconnected, the owner of the service shall be requested to supervise the uncovering of the service during the excavation.

(4) Pipes, conduits and cables for gas, electrical and other services in an excavation shall be supported to prevent their failure or breakage. O. Reg. 213/91, s. 228.

The current minimum standard contained in the Ontario Energy Board's service quality requirements is that underground cable locates must be completed within 5 working days of a customer's request, at least 90% of the time. For customers requesting a specific date, the locate must be completed within 5 working days of the requested date. Since the development of the service quality indicators in 1999, Ontario Regulation 22/04 has been proclaimed in force. Adherence to the standards set out in Regulation 22/04 is a legal requirement.

The 2009 cost for underground cable locating has been budgeted in accounts 5070, 5075, 5040 & 5045 totaling $92,650.

4.3 Elbows and Terminators

High voltage elbow and underground cable terminator inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Elbows and terminators are visually inspected according to the Minimum Inspection Requirements in the Distribution system Code (every 3 years Urban and every 6 years rural), which are inspected by the infra-red scanning program. Underground transformers have their lids opened and inspected by the infra-red scanning process. Damaged elbows and terminators are repaired or replaced as required.

Innisfil Hydro does not log the number of elbows or cable terminators in its distribution system. The adjacent asset is nomenclatured being a switch, transformer or cubicle. The standard for underground distribution is to use 28 kV class equipment even on 8.32kV distribution. This standardization improves reliability and allows for easier voltage conversion upgrades. Underground cables and terminators are amortized over their useful life of 25 years. The 2009 cost for inspecting underground elbows and terminators has been budgeted in account 5020 & 5045 totaling $49,800. Elbows and terminators are replaced on an 'as needed basis' and there are no pro-active replacement cycles established over the next five year horizon except in cable replacement projects.

4.4 Transformers

Underground transformer inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Elbows and terminators are visually inspected according to the Minimum Inspection Requirements in

the Distribution system Code (every 3 years Urban and every 6 years rural) which are inspected by the infra-red scanning program. Underground transformers have their lids opened and all connections are inspected by the infra-red scanning process. Damaged transformers or components are repaired or replaced as required. All transformers have the mineral oil tested and or verified so that all transformers are PCB free (< 50 PPM). Transformers are visually inspected according to the Minimum Inspection Requirements in the Distribution system Code (every 3 years Urban and every 6 years rural). The typical infra-red inspections address the following issues:

- Hot connects via infra red scanning
- Check for lock and penta bolt in place
- General appearance
- Placement of pad or vault
- Leaking oil
- Loose wires
- Bird or animal nests

Innisfil Hydro has not proposed funding to engage in the following inspections as mentioned in the DSC:

- Paint condition and corrosion
- Phase indicators and unit numbers matching operating map
- Grounding & connections
- Grade changes
- Access changes (shrubs, trees, etc)
- Pad mounted – lid damage, missing bolts, cabinet damage, public security lock damage and vandalism

For Innisfil Hydro to engage in a more detailed inspection, it is estimated that external contract costs of $40 per underground transformer would be required. This translates into an annual cost increase of $12,000 for 928 urban underground transformers which does not include internal costs or repairs.

Innisfil Hydro does not have any submersible transformers which operate below grade level. All underground transformers sit at or above grade, on top of a pad or vault.

All underground transformers are numbered, their secondary services are tagged as are the high voltage elbows. Underground transformers are amortized over their useful life of 25 years. The 2009 cost for inspecting underground transformers has been budgeted in the infra-red scanning budget. The 2009 cost for infra-red scanning underground transformers has been budgeted in account 5020 & 5045 totaling $49,800.

Transformers are changed with different sized units as needed. Transformers are replaced when they fail do to lightning strike, vehicle accident or internal/external problems. The following underground transformer addition and replacement schedule has been incorporated to deal with capital requirements:

Underground Transformers

	2008	2009	2010	2011	2012	2013
Total Count	904	934	965	997	1,030	1,064
Replacement	7	7	8	8	8	9
Additional	30	31	32	50	75	85

All additional transformers are required to meet load growth and load demand.

4.5 Primary Cables

Underground primary cable inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. With respect to underground systems, riser poles are checked by overhead patrols with a visual check of cable, cable guards, terminators and arrestors. While it is not possible to inspect underground cable directly, the system may be checked for exposed cable and or grade changes that may indicate that the cable has been brought too close to the surface.

The majority of primary underground cable in Innisfil is 'cross-linked, polymer encased' and in duct. Underground cables are amortized over their useful life of 25 years. Cables with a premature failure rate are repaired or replaced as required. The five year capital plan identifies areas that require underground cable replacements. These areas are mainly in the Sandy Cove North subdivision. The 2009 cost for maintaining and inspecting underground primary services has been budgeted in account 5150 totaling $13,050.

4.6 Secondary Services

Underground secondary service inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. With respect to underground systems, riser poles are checked by an overhead patrol with a visual check of cable, cable guards and connections. While it is not possible to inspect underground cable directly, the system may be checked for exposed cable and or grade changes that may indicate that the cable has been brought too close to the surface.

Approximate 30 spans of secondary buss replacement have been budgeted to replace. The old buss works that is now starting to loose its insulation from UV and other weather related factors is becoming a danger to working utility staff and wildlife. The old secondary buss is removed from service and the new larger buss is installed, thus handling higher capacities and lower line loses.

The majority of 120/240V underground secondary service wire in Innisfil is 300V aluminum secondary cable and in duct. The majority of 600/347V underground secondary service wire in Innisfil is 600V aluminum secondary cable and in duct. Underground secondary services are amortized over their useful life of 25 years. Secondary services with a premature failure rate are repaired or replaced as required. The 2009 cost for maintaining and inspecting underground secondary services has been budgeted in account 5155 totaling $64,550.

4.7 Grounding

Lightning from storms in can cause extreme damage on hydro utility equipment and subsequently cause prolonged customer interruptions. Lightning mitigation that includes good grounding has for the longest time been on the fore front of Innisfil Hydro's operating plan. Past capital budgets has had tens of thousands of dollars put in to arrestor and grounding installations to protect Innisfil Hydro's assets. Older installations like overhead and underground transformers installations, steel cross arm locations and separate dead end arrestor locations that have been existing for many years, have been found in the past to have the ground rods decay below the ground line. Acidic soils and moisture cause older galvanized steel ground rods to decay to the point where only a few feet are left from a ten foot rod. This deterioration causes high resistance in the grounding system and decreases the ability to prevent catastrophic lightning damage to Innisfil Hydro's and customers' equipment. Ground rod resistance testing is a program that can be implemented to check the resistance at individual locations. If the grounding is unsatisfactory by means of a ground rod resistance tester, then repair or replacement will need to be made to the grounding deficiency. If an approximate 300 lightning arrestor locations were done yearly, $20,000 would be needed. This amount has not been budgeted in the 2009 capital or maintenance budgets. Also not budgeted for are inspections to approximately 3100 transformer grounding locations and over 100 miscellaneous other grounding points within Innisfil Hydro's system.

4.8 Mapping

Mapping inspection and verification is mentioned in the DSC Minimum Maintenance Standards, (Phase indicators and unit numbers match operating map where used).

Although extreme due diligence as a rule warrants the best upkeep of mapping information, errors can still occur with even the greatest care. These operational maps describe the sub-transmission and distribution systems and are what crews and staff use to guide them in the restoration of power or for switching to complete jobs. If changes have been made without notification or open points moved in the field, time is required to verify theses problems in the maps. The end result can mean longer interruption times to customers in outage situations or worse, confusion of field staff risking their health safety. Nomenclature checks, map verification and open point confirmation should be done on a yearly basis to ensure that all maps match the actual field conditions in service. An amount of $12,500 is required to verify operation maps in the field, which has not been budgeted for in 2009.

5.0 Distribution Stations

5.1 Monthly Inspection

Distribution station inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Distribution stations in Innisfil are connected to the 44kV system on the primary side and the 27.6kV or 8.32kV system on the secondary side. Distribution stations are necessary to reduce the 44 kV sub-transmission voltage so that it can be utilized for single phase loads (< 35 kV). The 44 kV sub-transmission voltage is necessary to contend with the voltage losses engendered by the vast distances of the circuits. There are presently 9 distribution stations in service which are amortized over 25 years. Two stations are 44 kV – 27.6 kV and the rest are 44 kV – 8.32 KV. It is expected that the actual transformer replacement will need to occur after 50 years of service. Within the foreseeable five year horizon, actual transformer replacements are not anticipated according to distribution station records below.

Monthly inspections are undertaken for both rural and urban distribution station sites. The inspection involves the following parameters:

- Vegetation
- Fencing
- Litter
- Health & Safety
- Station Grounding
- Condition of SCADA building
- Transformer temperature
- Reclosure operations

There are ten privately owned 44 kV transformer stations connected to Innisfil Hydro's distribution system. Innisfil Hydro performs monthly inspections on privately owned stations to assure continued integrity with regard to reliability and health and safety. Since privately owned stations are connected directly to Innisfil Hydro's system, power quality problems at the private station can affect other customers on Innisfil Hydro's system. Innisfil Hydro's inspection forms are sent directly to the private station owners so that any remedial action can be undertaken.

The 2009 cost for monthly inspections is budgeted in account 5016 totaling $7,400. Annual distribution station maintenance includes weed and vegetation control, grass cutting, snow plowing, supervisory control and data acquisition (SCADA) maintenance. The 2009 cost for annual maintenance is budgeted in accounts 5114, 5125 and 5012 totaling $191,300.

5.2 Major Service

On a four year rotation, distribution stations are switched out of service and maintenance performed. This maintenance service includes the following:

- Bus connection inspection and tightening
- Ground resistance test
- Transformer oil analysis
- Switch cleaning and lubrication
- Inspection and cleaning of terminators, insulators, arrestors
- Cleaning of site, structures and hardware.

Substation maintenance crews generally perform major service over a 1-2 day period. Failure to perform major service could affect system reliability and the life-span of the related equipment. The cost for performing major distribution station service and maintenance for 2009 is budgeted in account 5114 totaling $39,300. This excludes any repairs or oil related problems. For example, filtering oil in a distribution station transformer may cost approximately $15,000. There is no schedule to replace any substation transformer within the next five year horizon.

Distribution Stations – Transformer Year of Manufacture

Station	Serial Number	Year of Manufacture
Big Bay Pt. DS	1-3552	1971
Bob Deugo DS	05-1996	2006
Brian Wilson DS – T1	T60841	1991
Brian Wilson DS – T2	146 330 1002	1991
Cedar Point DS	T60243-1	1976
Cedar Point DS Spare	87-367 (2 MVA)	1987
Cedar Point DS Spare	W1135-2 (5 MVA)	1967
Innisfil DS	T60347	1978
Lefroy DS	1-3504	1970
Leonards Bch.DS	1-3800	1974
Sandy Cove DS	I-3899	1975
Sandy Cove DS Spare	2-350318	1982
Stroud DS	B3S6058	1969

6.0 Metering

6.1 Wholesale Meters

Innisfil Hydro has six wholesale meters within its distribution system. These meters are pole mounted and measure the electrical energy entering Innisfil Hydro's distribution territory from Hydro One. Four of the wholesale meters are on 44 kV circuits and two are on 8.32 kV circuits. Innisfil Hydro is a 'Market Participant' as defined by the Independent Electricity System Operator. The meters are regulated under the authority of Measurement Canada. The wholesale meters and accompanying instrument transformers are certified once every six years, after which they must be re-sealed by a licensed Meter Service Provider. Innisfil Hydro has contracted with Oshawa PUC Services Inc. to perform licensed meter services.

Wholesale meters are patrolled with periodic line patrols and infra-red scanning on an annual basis. The meters are connected to Bell Canada's land lines and are read on a daily basis by the IESO and Innsifil Hydro's agent through phone lines. Any meter reading problems are investigated immediately by Innisfil Hydro and or Oshawa PUC Services for remedial service. Wholesale meters are amortized over their useful life of 25 years. The 2009 cost for maintaining wholesale meters is budgeted in account 5175 totaling $36,000.

6.1 Retail Meters

Innisfil Hydro has over 14,000 retail meters in service. These range from typical 240 V house meters to 44 kV primary meters at privately owned transformer stations. The demarcation point between Innisfil Hydro and the Customers' property is specified in Innisfil Hydro's Condition of Service.

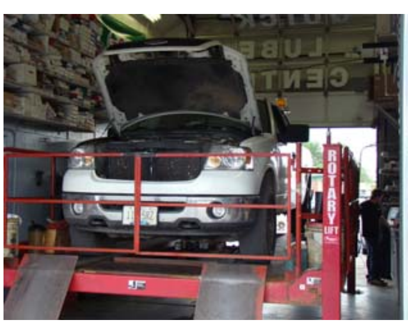
The meters are regulated under the authority of Measurement Canada with meter seals ranging from 6-12 years, after which the meters must be resealed or if sample testing shows meter accuracy for residential meters, then sample groups can pass inspection without being re-sealed.

All retail non-interval meters are read on a monthly basis by human meter readers. Interval meters are read on a daily basis by Innisfil Hydro's agent though phone lines. Any meter reading problems are reported immediately for remedial action by Innisfil Hydro.

Retail meters are amortized over their useful life of 25 years. The 2009 annual cost for maintaining retail meters is budgeted in account 5065 totaling $67,750.

7.0 Vehicle Maintenance

7.1 Service



Innisfil Hydro contracts out all line and substation maintenance and construction so it does not incorporate line trucks and trailers in its fleet. Innisfil Hydro does not have internal vehicle maintenance staff or equipment and out-sources that function. Innisfil Hydro has ten motorized vehicles in its fleet consisting of 5 pick-up trucks, 2 vans, 2 Ford Escape Hybrids and

1 forklift. The vehicle replacement plan includes the purchase of two new Ford Escape Hybrids in 2009 to meet the replacement schedule and this will also mitigate the impact of fuel prices. These vehicles do not meet the weight threshold for Commercial Vehicle Operator Registration (CVOR). They receive basic maintenance in accordance with the manufacturer's recommendation. Any other maintenance or repairs are conducted in accordance with the Ministry of Transportation vehicle safety standards.

Vehicles are amortized over their useful life of 10 years. The following actions are undertaken to extend the useful life of vehicles:

- The availability to rotate vehicles between users to maximize the mileage driven in respect of the vehicle's age.
- The availability to transfer a vehicle to another department where usage is less severe or addressing a need for a spare vehicle or for parts.
- Analysis if the vehicle in sufficiently good shape to extend its useful life past the evaluation criteria.

The 2009 cost for maintaining Innisfil Hydro's fleet is $83,000 allocated to projects on a vehicular hourly basis.

7.2 Replacement

The basic criterion for vehicle replacement is 10 years of age or 200,000 km. Vehicles deteriorate differently depending on factors such as quality of manufacture and the severity of usage. Vehicle replacement is not intended to follow a stringent set of rules that does not allow for the flexibility needed for asset management, but is a working target. Criteria that affects vehicle useful life includes:

- Other facets or technologies required of the vehicle that can no longer receive maintenance support or uses parts or updates that can no longer be supplied.
- Analysis if the vehicle a "lemon" where expenses exceed depreciation which may warrant an early retirement date.
- Analysis if the vehicle no longer has a useful purpose or is in sufficiently in poor shape to warrant an early retirement date.
- Sufficient mechanical or structural damage caused by an accident or abnormal wear.

Vehicles that exhibit good service past 10 years of age or greater than 200,000 km may be kept in the fleet as determined by staff. Maintenance costs will be monitored to determine if they exceed the depreciation of a replacement vehicle. In 2009, two vehicles are planned to be replaced with Hybrids at a cost of $77,000. Surplus equipment is sold or disposed of for the greatest benefit to Innisfil Hydro.

YEAR	VEHICLE	TRUCK #	Replacement
1999	CHEVY ASTRO VAN	88	2009
1999	CHEVY ASTRO VAN	89	2009
2000	CHEVY SILVERADO PICK-UP	86	2010
2004	CHEVY SILVERADO PICK-UP	84	2014
2005	DODGE RAM PICK-UP	91	2015
2005	DODGE RAM PICK-UP	87	2015
2006	FORD F150	93	2016
2008	FORD ESCAPE (HYBRID)	92	2018
2008	FORD ESCAPE (HYBRID)	85	2018

8.0 Property Maintenance

8.1 Sites

Innisfil Hydro owns 10 substation sites and one 4 acre head off site. These sites have the grass cut and snow plowed as required. Innisfil hydro also owns numerous registered easements and non-registered easements for distribution assets registered on title, requiring on-going monitoring in an effort to protect the easement rights of Innisfil Hydro.

8.2 Buildings

The head office site includes one wood frame building for Customer Service, one wood frame building for Engineering/finance and one wood framed building for the warehouse. Parking for ~ 30 cars is provided along with outside storage for line hardware. The site is in a commercially zoned area with architectural control zoned across the road. The head office site is maintained to meet building code standards, energy efficiency and health and safety requirements. Buildings are depreciated over a 25 year period over their useful life. The cost for maintaining the head office is budgeted for 2009 in accounts 5085, 5340 and 5620 totaling $541,150.

9.0 Equipment Maintenance

9.1 Office Equipment

Office equipment includes desks, chairs, filing cabinets, office partitions etc. This equipment is depreciated over a 10 year useful life span. Repairs to office furniture occurs as needed and replacements occur generally after 10 years. When the need for expansion occurs and new furniture is purchased. Displaced office equipment is re-used or re-cycled to other areas of the corporation where appropriate. The 2009 cost of office equipment is budgeted in account 1915 totaling $15,000. Surplus equipment is sold or disposed of for the greatest benefit to Innisfil Hydro.

9.2 Computer Hardware

Computer hardware includes the phone system, photo copiers, fax machines, printers, monitors, personal computers, network servers, power supplies, network cables etc. Computer hardware is depreciated over a five year useful lifespan. The parameters for the replacement of computer hardware is as follows:

- Improved space and speed requirements from new software
- New technologies not supported by existing equipment.
- Existing equipment not supported by suppliers
- Reliability problems from existing equipment

When the need for expansion occurs and new computer equipment is purchased, displaced computer equipment is re-used or re-cycled to other areas of the corporation where appropriate. The 2009 cost of computer hardware is budgeted in account 1920 totaling $95,000. Surplus equipment is sold or disposed of for the greatest benefit to Innisfil Hydro.

9.3 Line Tools

Innisfil Hydro does not have any in-house Line Staff so Line equipment is generally supplied by the independent Line Contractor. Innisfil Hydro does purchase and operates some line tools such as underground cable locating equipment, fault locating equipment, meter analyzers and AVO meters, etc. These tools are depreciated over the ten year lifespan of the equipment. The equipment is generally kept until it's no longer working or cost beneficial to maintain or replaced with new technologies. The 2009 cost of tools is budgeted in accounts 1935, 1940 and 1945 totaling $21,200.

10.0 Innisfil Beach Road Urbanization

The Town of Innisfil is planning to 'urbanize' a section of Innisfil Beach Road between the 20th Side Road and Lake Simcoe. In 2005, the Town retained a consulting firm of MBPD to undertake an Urban Design Study of Innisfil Beach Road in the community of Alcona. The intent was to determine the future urban design of the public road allowance and the lands and buildings adjoining the road. There has been a series of public consultations and public participation involving members of the general public, landowners, business operators and members of Town staff and Council.

As a result of this consultation process and the work of MBPD, a draft document has been prepared entitled the Innisfil Beach Road Urban Design Study and Guidelines. A presentation was made to Council on February 28, 2007 by the Town's consultants.

This is a multi-year project involving property acquisition, road widening, cubs, gutters, roadside parking and streetscaping.

The Town of Innisfil is planning to finalize the urbanization design in 2008 through a By-law. The same By-law will be requiring utility relocates to be underground. Innisfil Hydro will be provided notice in writing to relocate a portion of the overhead infrastructure due to the improvement of the highway. According to the *Public Service Works on Highways Act., R.S.O. 1990, CHAPTER P.49,* without a cost sharing agreement between the Road Authority (Town of Innisfil) and the Operating Corporation (Innisfil Hydro), the Town of Innisfil will be responsible for ½ of the labour costs and Innisfil

Hydro shall be responsible for the other ½ of labour costs and all material costs as outlined in Sec.2 below:

Notice to operating corporation to take up works

2. (1) *Where in the course of constructing, reconstructing, changing, altering or improving a highway it becomes necessary to take up, remove or change the location of appliances or works placed on or under the highway by the operating corporation, the road authority may by notice in writing served personally or by registered mail require the operating corporation, without prejudice to their respective rights under section 3, so to do on or before the date specified in the notice. R.S.O. 1990, c. P.49, s. 2 (1).*

Apportionment of costs of taking up

(2) The road authority and the operating corporation may agree upon the apportionment of the cost of labour employed in such taking up, removal or change, but, subject to section 3, in default of agreement such cost shall be apportioned equally between the road authority and the operating corporation, and all other costs of the work shall be borne by the operating corporation. R.S.O. 1990, c. P.49, s. 2 (2).

If Town of Innisfil incurs a loss due to neglect by Innisfil Hydro, *Sec 2 (5) of the Public Service Works on Highways Act., R.S.O. 1990, CHAPTER P.49, indicates that Innisfil Hydro shall make due compensation as follows:*

Compensation

(5) Where a road authority incurs a loss or expense by reason of an operating corporation neglecting to take up, remove or change the location of appliances or works by the date specified in a notice given under subsection (1) or such date as altered by a judge under subsection (4), the operating corporation shall make due compensation to the road authority for such loss or expense, and a claim for compensation, if not agreed upon by the operating corporation and the road authority, shall be determined by the Ontario Municipal Board. R.S.O. 1990, c. P.49, s. 2 (5).

In an effort to mitigate any claims for compensation (*R.S.O. 1990, c. P.49, s. 2 (5)),* Innisfil Hydro has budgeted capital funds for the relocation of distribution assets on Innisfil Beach Road as follows:

2008 - $750,000

2009 - $788,000

2010 - $828,000

2011 - $867,000

11.0 long Range Load Projections

Long range load projections have been plotted from years 2006 to 2031. The parameters for the load growth model utilizes the County of Simcoe's Proposed Official Plan whereby the Town of Innisfil's population will grow to 65,000 by 2031. Innisfil Hydro currently has a supply limit of 63 MW from Hydro One and is projected to grow to 136 MW in 2031. This current supply limit will be exceeded so Innisfil Hydro is planning to acquire two new feeders from Hydro One. The two new feeders will be able to supply Innisfil until 2022. At that time, one more feeder will be required until full build-out in 2031. Future demand has been estimated at 2 kW / resident which will include loads for commercial requirements such as schools, stores and businesses.

25 Year Innisfil Hydro Supply Analysis (2006-2031)

G. Shaparew July 29, 2008

Two New 44 kV Feeders installed

23 MW Required

Will Require 1-44 kV feeder

							New DS		New DS					
Available Supply From Hydro One (MW)														
Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Present	63	63	63	63	63	63	63	63	63	63	63	63	63	63
+ 2 feeders (09)	63	63	63	63	63	113	113	113	113	113	113	113	113	113
Projected Load in Innisfil (MW)														
135,000 Population														
Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
OP MW	53.7	62.7	48.2	49	66	67	68	70	71	74	76	79	82	85
With BBP MW	53.7	62.7	48.2	49	66	68	69	71	74	77	80	84	88	92
population (000s)	30.5	30.9	32.4	32.8	33.2	33.6	34.1	34.8	35.7	36.8	38	39.3	40.8	42.5
Increase		400	400	400	400	400	500	700	900	1100	1200	1300	1500	1700
BBP Requirements (MW)								0.34	1.01	1.68	2.35	3.35	4.36	5.36
BBP Units						100	200	200	200	300	300	300	400	2000
Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Customers	13700	13864	13933	14058	14266	14576	15007	15881	17137	17637	18182	18773	19455	20228

	New DS			New DS				New DS						
Available Supply From Hydro One (MW)														
Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Present	63	63	63	63	63	63	63	63	63	63	63	63	63	63
+ 2 feeders (09)	113	113	113	113	113	138	138	138	138	138	138	138	138	138
Projected Load in Innisfil (MW)														
135,000 Population														
Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
OP MW	89	93	96	100	104	108	112	115	119	122	125	127	128	129
With BBP MW	96	99	103	107	111	115	118	122	126	129	132	133	135	136
population (000s)	44.4	46.3	48.2	50.1	52	53.9	55.8	57.7	59.4	61.1	62.6	63.3	64	64.7
Increase	1900	1900	1900	1900	1900	1900	1900	1900	1700	1700	1500	700	700	700
BBP Requirements (MW)	6.70	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
BBP Units														
Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Customers	21092	21955	22819	23682	24546	25410	26273	27137	27910	28682	29364	29682	30001	30319

Note Big Bay Point (BBP) development does not add population, all resort dwellings
Estimate 2kW / resident, which includes commercial load

Two New 44 kV Feeders into Innisfil Hydro

In the early part of this decade, Hydro One had been working with Simcoe County LDCs to develop a South Simcoe Load Growth Strategy. One of the outcomes of this strategy was to build a new transformer station (Everett TS) to provide much needed capacity relief for Alliston TS, which was overloaded during peak periods. The new TS has opened up two feeder locations (9M3 & 9M6), which are available to Innisfil for growth requirements. These two feeders will provide future load growth capacity as well as much needed back up for the other 44kV feeders in Innisfil. The two main 44 kV feeders supplying Innisfil are on the same pole line, coming 12 km outside of Innisfil. Problems with one or both circuits create huge supply problems for Innisfil Hydro. The lock-out of both feeders in July 2008 had blacked out 2/3 of the entire Town of Innisfil for four hours. Having feeders 9M3 & 9M6 available would have limited that interruption to about 10 minutes. The estimated contribution required to Hydro One is $500k. The project starting date is 2009 and in-service date is 2009.

An approximate four (4) km of double circuit 44 kV sub-transmission will be built from the 10 Sideroad of Essa south on Highway 27 and across the 5th Line of Innisfil to the 5 Sideroad. The two (2) new incoming feeders should provide enough capacity for Innisfil until 2022. Approximately sixty-five (65) poles will replace existing smaller single phase and three phase poles in order to accommodate for the sub-transmission circuits. Within the scope of this project, two metering units and three (3) 44 kV SCADA load break switches are to be installed; two (2) switches at the Innisfil Hydro/Hydro One border and a third as a paralleling point within Innisfil Hydro's system. The estimated cost of this project is $853k. The project starting date is 2009 and in-service date is 2009.

Failure for Innisfil Hydro to secure feeders 9M3 & 9M6 at this time will jeopardize Innisfil Hydro's ability to secure needed supply according to the Town of Innisfil and the County of Sincoe official plans. Everett TS and Alliston TS have finite feeder positions with limited feeder egress out of the stations. Future feeder locations simply will not be available. Innisfil Hydro may be forced to fund a complete transformer station in excess of 10 million dollars if it does not secure the two feeder positions at this time.

APPENDIX C - MINIMUM INSPECTION REQUIREMENTS

C.1 DISTRIBUTION INSPECTION STANDARDS

Inspection Cycles

A distributor should ensure that only persons qualified under the Occupation of Health and Safety Act are involved in inspection activities. Since some inspections can expose inspectors to energized lines or high voltage circuits and equipment, and may include inspection and repair, a qualified person should be assigned to this work. This assumes that they are both properly trained to protect both themselves and the public, and to respond to those emergencies, which may arise during inspections.

In developing the standards for facilities inspections, the patrol inspection is defined as follows:

> Patrol or simple visual inspections consists of walking, driving or flying by equipment to identify obvious structural problems and hazards such as leaning power poles, damaged equipment enclosures, and vandalism. In cases where a patrol notices that a problem exists or identifies a condition that warrants a more thorough or rigorous inspection, patrol may then include situations where structures are opened as necessary, and individual pieces of equipment carefully observed and their condition noted and recorded. The specifics of these inspections would be recorded, and a summary document prepared in the distributor's annual reports as part of their rates or licensing submissions.

In all cases, a distributor is responsible to ensure that appropriate follow up and corrective action is taken regarding problems identified during a patrol.

The Board or a Board-designated party reserves the right to conduct random audits of inspection reports to ensure that appropriate follow up and corrective action is taken regarding problems identified during a patrol.

It is expected that distributors will file both annual summary reports of detailed patrol inspection activities that have taken place during the previous year as well as an outline of inspection plans ("compliance plans") for the forthcoming year.

Inspection cycles are categorized by the following major distribution facilities:

Distribution Transformers
Stations
Switching and Protective Devices
Regulators
Capacitors
Conductors and Cables

Vegetation
Poles/Supports
Civil Infrastructure

For each of these facilities, the distributor shall further distinguish between overhead facilities, underground facilities. The distributor shall also separate according to the facilities' location and the relative population density in the locale.

- **Rural** means those areas that are less populous suburban areas and are outside of a standard metropolitan area. Generally, rural will be defined on a circuit or sub-circuit basis by each utility, as areas with a line density of less than 60 customers per kilometer of line. It is recognized that there may be circumstances where the utility might want to treat something as urban though it would otherwise be defined as 'rural' according to this definition.

- **Urban**, means areas with higher density and, by definition pose safety and reliability consequences to greater numbers of people.

The following description provides a list of the requirements to be expected from a typical distribution line patrol inspection in terms of the types of defects that may be detected visually. Clearly, the list will vary depending on the equipment specifics and locations, thus this should be viewed as a 'generic' patrol expectation.

Transformers and switching kiosks:
Paint condition and corrosion
Placement on pad or vault
Check for lock and penta bolt in place
Grading changes
Access changes (Shrubs, trees, etc.)
Phase indicators and unit numbers match operating map (where used)
Leaking oil
Flashed or cracked insulators
Pad mounted – lid damage, missing bolts, cabinet damage, public security lock damage

Substation- May consist of one or all types of equipment listed

Switching/Protective Devices
Overhead
Bent, broken bushings and cutouts,
Damaged lightning arresters, control boxes, current and potential transformers
Underground
Security and structural condition of enclosure
Pad mounted
Security and structural condition of enclosure

Regulators

Condition of bushings
Tank corrosion/leaks
Damaged disconnect switches or lightning arresters

Capacitors

Condition of bushings
Tank corrosion/leaks
Damaged cutouts, disconnects or control cabinet

Conductors and Cables

Low conductor clearance
Broken/frayed conductors or tie wires
Tree conditions, exposed broken ground conductors
Broken strands, bird caging, and excessive or inadequate sag.
Insulation fraying on secondary especially open wire

Poles/Supports:

Bent, cracked or broken poles
Excessive surface wear or scaling
Loose, cracked or broken cross arms and brackets
Woodpecker or insect damage, bird nests
Loose or unattached guy wires or stubs
Guy strain insulators pulled apart or broken
Guy guards out of position or missing
Grading changes, or washouts
Indications of burning

Hardware and attachments:

Loose or missing hardware
Insulators unattached from pins
Conductor unattached from insulators
Insulators flashed over or obviously contaminated (difficult to see)
Tie wires unraveled
Ground wire broken or removed
Ground wire guards removed or broken

Equipment Installations (includes transformers)

Contamination/discoloration of bushings
Oil leaks
Rust
Ground lead attachments
Ground wires on arrestors unattached
Bird or animal nests
Vines or brush growth interference

Evidence of bushing flashover
Accessibility compromised

Vegetation and Right of Way:
Leaning or broken “danger” trees
Growth into line of “climbing” trees
Unapproved/unsafe occupation or secondary use

Civil Infrastructure - For example, buildings that house the equipment may need attention (cracking, fire hazards, etc). In addition, cable chambers, underground vaults and tunnels crossing the rail track or water are also included in this category. These inspections would likely be conducted in the patrol of the equipment with which they are “associated.”

Underground Systems:

With respect to underground systems, riser poles should be checked as with an overhead patrol, with a visual check of cable, cable guards, terminators and arrestors. While it is not possible to inspect underground cable directly, the system may be checked for exposed cable and or grade changes that may indicate that the cable has been brought too close to the surface. Patrol inspection of cable chambers is not required since a visual inspection will not reveal faults because the failure mechanism for underground cable (e.g. voids, water trees) is not visually detectable.

Cable is hard to check, but the system can be checked for exposed cable and/or grading changes that may have brought cable or wire too close to the surface.

APPENDIX C - MINIMUM INSPECTION REQUIREMENTS

TABLE C-1
Electric Utility System Inspection Cycles
(Maximum Intervals in Years)

Major or Substantial Distribution Facility*	Patrol	Patrol
Distribution Transformers	**Urban**	**Rural**
Overhead	3	6
Submersible	3	6
Vault	3	6
Pad Mounted	3	6

Stations (see note below)	Outdoor Open	Outdoor Enclosed	Indoor Enclosed	Outdoor Open	Outdoor Enclosed	Indoor Enclosed
Transformer Station	1 month	1	1	6 month	1	1
Distribution Station	1 month	1	1	6 month	1	1
Customer Specific Substation	1	3	3	1	3	3

Lines and Associated Equipment		
Regulators	3	6
Switching and Protective Devices	3	6
Capacitors	3	6
Conductors and Cables		
Overhead	3	6
Underground	3	6
Submarine	3	6
Vegetation (see note below)	3	6
Poles	3	6
Civil Infrastructure	3	6

APPENDIX C - MINIMUM INSPECTION REQUIREMENTS

Notes to Table C-1:

1. The above distribution system patrol cycles form part of the regulatory framework and are minimum inspection requirements for each major or substantial distribution component and related hardware.

2. A distributor may determine that more frequent inspections may be required due to local conditions such as geographic location, climate, environmental conditions such as air pollution or highway salt spray, technologies available to perform the inspection, type and vintage of distribution technology in place, manufacturer specifications, system design, or relative importance to overall system reliability of a particular piece of equipment or portion of the distributor's distribution system.

   The burden of proof is on the distributor to demonstrate that it should not have to comply with these the inspection schedules or requirement in Table C-I. To demonstrate that it should not have to comply with these inspection schedules, the distributor would have to present a comprehensive and detailed case establishing:

   Revised inspection cycles may be allowed when justified by:

   - Documented historical good utility maintenance and inspection practices, including a program to manage reliability.
   - Alternative or additional maintenance activities that are practiced by the utility and can be demonstrated as being practiced.
   - Achieved reliability performance. The utility will be required to submit both the current and historic reliability statistics over five years. These statistics must be verifiable. This will be measured by the following:
     - Once the data is available over the course of Generation 1 and 2 of the PBR regime, the reliability indices that are better than the average of distributors which are comparable in size and type. The reliability indices to be used are those that are defined over time in the PBR regime, including initially SAIDI, CAIDI and SAIFI averaged over the previous three year period, and;
     - The reliability indices over time for the individual utility that are at least as good, if not better, than the average of the indices over the previous five year period. Again, the reliability indices to be used are those that are defined over time in the PBR regime, including initially SAIDI, CAIDI and SAIFI averaged over the previous five-year period.

3. The method by which inspection cycles are structured and the work carried out is at the discretion of the distributor. The above table is organized according to major classification of equipment, however distributors may choose to conduct and record the inspections on some other basis such as:

   - Circuit or feeder basis
   - Overhead & underground
   - System voltage
   - Dividing its service area into geographical areas
   - Other

   It is intended that if the inspections are organized by one of the above approaches, all major equipment categories identified in the table and related hardware along the line or within the area will be inspected. It is intended that the utility would perform the inspection on a minimum of approximately 1/3 (urban) or 1/6 (rural) of their system in each year, such that at the end of the first term of the PBR framework, a utility would have performed an inspection of their entire system in urban areas and approximately half of rural systems. If, in any one year of the PBR framework, a utility has performed the inspection on less or more than the 1/3 (urban) or 1/6 (rural) of their system, the utility would provide an explanation of this deviation in their annual submission. For clarity, the plant will be inspected on a cyclical basis, and the cyclical interval is specific to a particular region or portion of plant, and not on the system as a whole.

4. "Civil Infrastructure": Refers to facilities and structures such as tunnels, ducts suspended from or attached to bridges, underground chambers and hand holes, towers supporting distribution plant, communication towers, buildings that house substation equipment. It is intended that civil infrastructure will be inspected as part of the patrol of the distribution system or in the course of doing normal, routine utility work. It is recognized that there may be instances where it will be extremely difficult to perform a visual inspection (e.g. where access is restricted due to energized equipment in cable chambers), and therefore the civil infrastructure associated with this would be inspected in the course of doing normal utility work which would require entrance to the chamber, which would require the utility to de-energize the equipment. In other words, the equipment should not be de-energized simply to comply with this scheduled inspection routine.

5. "Patrol": Visual inspection of major distribution system components to identify problems and hazards such as leaning poles, damaged equipment enclosures, and vandalism. This will include an inspection of all related peripheral equipment, hardware, connections, all supports and attachments (e.g. cross arms, braces, guys and anchors). This would also include an assessment of vegetation encroachment on right-of-ways.

   The patrol may highlight that a problem exists or may identify conditions that warrant a more thorough or rigorous inspection or the need for specific maintenance. The specific follow up or corrective action shall be according to the best judgment of the distributor considering best industry practices. To further clarify the nature of problems detected during the inspection, the distributor may choose to utilize diagnostic tools such as infrared thermography, ultrasonic testing or other technologies that may emerge. Several technologies are also available for wood pole testing. Distributors may choose, (as post inspection follow up or ongoing maintenance), to conduct tests of major distribution system components on a sample basis. Issues such as the age, equipment design, exposure to adverse conditions, manufacturer specifications, and relative impact on overall system reliability may influence a distributor's decisions regarding corrective action and application of these diagnostic technologies following a patrol. In all cases, a distributor is responsible to ensure that appropriate follow up and corrective action is taken regarding problems identified during a patrol. This may entail upgrade or replacement of specific components or equipment.

   Maintenance activities and schedules are not specified in the above table and are left to the discretion of the distributor. It is not practical to attempt to establish a regulatory regime for literally hundreds of maintenance activities that range from insulator washing, cable replacement, CO_2 cleaning of switchgear, to gas-in-oil testing of station transformers, etc. The absence of more detailed inspection or maintenance criteria in the above table in no way reduces the distributor's obligation to maintain the distribution system in a safe and serviceable condition.

   The Board or a Board- designated party reserves the right to conduct random audits of inspection reports to ensure that appropriate follow up and corrective action is taken regarding problems identified during a patrol.

7. "Rural": Generally will be defined on a circuit or sub-circuit basis by each distributor, as areas with a customer density of less than 60 customers per kilometer of line. It is recognized that there may be circumstances where the distributor may choose to treat some parts of its distribution system as urban though it is "rural" according to this definition.

   "Urban": Each distributor will define "Urban", or more populated areas, on a circuit or sub-circuit basis, as areas with higher density and, by definition pose safety and reliability consequences to greater numbers of people.

8. "Stations": The terms "substations", "distribution /municipal stations", etc. Are frequently interpreted and applied differently by various distributors. In some jurisdictions the term "substation" refers to a large 125 MVA station directly connected to the 115 or 230 kV

transmission system while in other jurisdictions "substation" refers to a customer specific station that provides transformation from a distribution voltage to a utilization voltage of 600V for example.

The impact on overall distribution system reliability of any particular station varies considerably according to the nature of the station and local system design. Specific station design features such as indoor versus outdoor may warrant different inspection cycles according to the relative exposure to unauthorized access and associated public safety concerns.

The following definitions are provided to assist with interpretation of the above table such that the resulting inspection cycles are appropriate for the nature of the station.

8.1 "Transformer Station" (TS): A transformation facility with the primary connected to the 115/ 230 kV or higher transmission system and the secondary operating at 50 kV or less.

8.2 "Distribution Station" (DS): Also known as "municipal Station (MS), a transformation facility with the primary operating at a sub transmission or distribution voltage and the secondary operating at lower distribution voltage. The upstream transformation facility will typically be a Transformer Station. A Distribution Station supplies main feeders for wide area distribution.

8.3 "Customer-Specific Substation": A transformation facility supplying a specific industrial/commercial customer. The primary operates at a distribution or sub transmission voltage and the secondary typically operates at 600V. The upstream station could be either of the stations identified in 8.1 or 8.2. Typically these facilities are on the customer's private property and include customer-owned equipment in addition to a Distributor-owned transformer.

8.4 "Outdoor Open": Typically refers to a station surrounded by a locked security fence. Within the station fence bare energized components operating at distribution voltage levels or higher are readily accessible. More frequent inspections are required for public safety considerations and to ensure integrity of the station fence.

8.5 "Outdoor Enclosed": Similar to 8.4 above however all bare live components are enclosed in locked metal enclosures. Due to reduced accessibility to energized components less frequent inspections are appropriate.

8.6 "Indoor": Typically refers to a station located within a secure building. Access by the public to bare energized components within the station is prevented by the building enclosure. Due to reduced exposure to unauthorized public access less frequent inspections are appropriate.

9. "Conductors and Cables: Underground": It is not possible to inspect underground cable directly, however, the system can be checked for exposed cable and or grade changes that may indicate that the cable has been brought too close to the surface. Patrol inspection of cable chambers is not required since a visual inspection will not reveal faults because the failure mechanism for underground cable (e.g. voids, water trees) is not visually detectable.

10. "Vegetation": Refers to encroachment of vegetation upon distribution lines on any right-of-way; either public road allowance or private property. It is intended that vegetation will be inspected as part of the regular patrol of distribution equipment.

C.2 DISTRIBUTION INSPECTION REPORTING

TABLE C-2
Sample Annual Inspection Summary Report

Distributor		
Reviewed by	**Name:**	**Position/Title:**
Date:	**Signature:**	

DESCRIPTION **Part 1 - Lines**		**Percentage of Distribution System Scheduled for Patrol (%)**	**Percentage of Distribution System Actually Patrolled (%)**	**Reason Patrol was not Completed**	**Date Patrol will be Completed**
Overhead Plant Transformers Switching & Protective Devices Regulators Capacitors Conductor Vegetation Poles Civil Infrastructure	**Urban**				
	Rural				
Underground Plant Transformers Switching & Protective Devices Regulators Capacitors Cable Civil Infrastructure	**Urban**				
	Rural				

Part 2 – Substations	**Number of Substations in Distribution System**	**No. of Substation Patrols Scheduled**	**No. of Scheduled Patrols not completed**	**Reason Patrols were not Completed**	**No. of Substations not Patrolled During Reporting Period**	**Date Substation Patrol Schedule will be Resumed**
Transformer Station						
Distribution Station						
Customer Specific Substation						

<u>Notes to Table C-2:</u>

APPENDIX C - MINIMUM INSPECTION REQUIREMENTS

1. This report provides a summary of the patrols scheduled and carried out during the year as well as the target dates for completion of patrols which were not completed as planned.

2. This format is a sample of a summary report for patrols carried out on a geographical, system characteristic (overheard or underground) basis.

3. Major equipment categories need not be reported separately however, all categories of equipment within the particular area or circuits shall be inspected.

4. Civil infrastructure is intended to be inspected as part of patrol of the distribution system or in the course of doing normal routine utility work.

5. This report is to be submitted to the OEB on an annual basis.

TABLE C-3
Sample Patrol Deficiency Record

Area/District ________________ **Date** __________________________

Circuit ______________________ **Patrolled by** ______________________

Grid ______________________ **Page** ______ of _____

Location	Equipment Id. No.	Equipment Classification	Repair Required/ Problem	Corrective Action Priority		Assigned to or Work Order No.	Date Repair Completed or Scheduled
				Grade 1	Grade 2		
Number of Deficiencies for the Circuit/Area							

Notes to Table C-3:

1. The format of this record is to be determined by the distributor based on their own system data input forms. This format is a sample for inspections done on a geographical or circuit basis and indicates the information that is expected to be collected.

2. Deficiencies and corrective action for all major equipment classifications for the area or circuit would be recorded.

3. Distributors are required to retain this information and make it available to the Board upon request.

4. Corrective Action Grade 1 is defined as a condition requiring urgent and immediate response and continued action until the condition is repaired or no longer presents a potential hazard.

5. Corrective Action Grade 2 is defined as a condition requiring timely corrective action to mitigate an existing condition which, at the time of identification, does not present an immediate hazard to the public, Distributor employees, or property.

RATE BASE MATERIALITY & VARIANCE ANALYSIS:

Innisfil Hydro has calculated the variance threshold on its rate base to be $170,000 in accordance with the Filing Requirements. This calculation is summarized in Table 1 below:

Table 1
Rate Base Materiality

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Bridge Year	2009 Test Year
Gross Fixed Assets	$35,058,164	$ 38,960,919	$40,409,084	$43,766,331	$50,177,741
Accumulated Depreciation	$18,087,071	$ 21,759,867	$23,388,379	$25,078,321	$26,972,674
Net Book Value	$16,971,093	$ 17,201,051	$17,020,706	$18,688,011	$23,205,068
Variance calc 1% NBV		$ 172,011	$170,207	$186,880	$232,051

The following Table 2 sets out Innisfil Hydro rate base and working capital calculations for 2006 Board Approved and Actual, 2007 Actual, 2008 Bridge Year and 2009 Test Year, and the following variances:

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

Table 2
Rate Base Variances

Description	2006 OEB Approved*	2006 Actual	Variance from 2006 OEB Approved	2007 Actual Year	Variance from 2006 Actual	2008 Bridge Year	Variance from 2007 Actual Year	2009 Test Year	Variance from 2008 Bridge Year
Gross Fixed Assets	35,058,164	38,960,919	3,902,755	40,409,084	1,448,165	43,766,331	3,357,247	50,177,741	6,411,410
Accumulated Depreciation	(18,087,071)	21,759,867	3,672,796	23,388,379	1,628,511	25,078,321	1,689,942	26,972,674	1,894,353
Net Book Value (Actual not approved)	16,971,093	17,201,051	229,958	17,020,706	(180,346)	18,688,011	1,667,305	23,205,068	4,517,057
Average Net Book Value(Act not App)	16,971,093	16,744,214	(226,879)	17,110,879	366,665	17,854,358	743,480	20,946,539	3,092,181
Working Capital	17,517,503	19,713,485	2,195,982	19,869,862	156,377	20,389,846	519,984	20,952,180	562,334
Working Capital Allowance	2,627,625	2,957,023	329,397	2,980,479	23,457	3,058,477	77,998	3,142,827	84,350
Rate Base	19,598,718	19,701,236	102,518	20,091,358	390,122	20,912,835	821,477	24,089,366	3,176,531

*Note: The 2006 OEB Approved rate base was determined through the 2006 EDR process and is based on the average of 2003 and 2004 year end balances adjusted for Tier 1 Adjustments. The variance between 2006 Actual and 2006 OEB Approved spans a 2 ½ year period.

Innisfil Hydro offers the following comments in respect of the relevant variances identified above:

2006 Actual:

The rate base for 2006 Actual increased over 2006 Board Approved by $102,518. This increase is made up of a decrease in average net assets of $226,879 and an increase in working capital allowance of $329,397. This increase in rate base represents changes from 2006 Board Approved, which was based on an average of 2003 and 2004 year end balances plus or minus Tier 1 adjustments as provided in the 2006 EDR Handbook. The increase in fixed assets is discussed in detail by capital project in Exhibit 2, Tab 3, Schedule 1.

2007 Actual:

The rate base for 2007 Actual increased over 2006 Actual by $390,122. This increase is made up of an increase in average net assets of $366,665. The increase in fixed assets is discussed in detail by capital project in Exhibit 2, Tab 3, Schedule 1.

The working capital allowance increased by $23,457. A detailed calculation of the working capital allowance for the 2007 Bridge Year can be found at Exhibit 2, Tab 4, Schedule 1.

2008 Bridge Year:

The total rate base for the 2008 Bridge Year is expected to be $20,912,835, which represents an increase of $821,477 over the 2007 Actual year. This change results in part from an increase in average net assets of $743,480. The increase in fixed assets is discussed in detail by capital project in Exhibit 2, Tab 3, Schedule 2.

The working capital allowance increased by $77,998 from 2007. A detailed calculation of the working capital allowance for the 2008 Bridge Year can be found at Exhibit 2, Tab 4, Schedule 1.

2009 Test Year:

As shown in Table 1 above, the total rate base in the 2009 test year is forecast to be $24,089,366. Average net fixed assets accounts for $20,946,539 of this total. The allowance for working capital totals $3,142,827

- **Comparison to 2008 Bridge Year:**

The total rate base is expected to be $3,176,531 higher in the 2009 Test Year than in the 2008 Bridge Year. This increase is shown in Table 1 above and is attributed primarily to an increase in average net fixed assets of $3,092,181. The increase in fixed assets is discussed in detail by capital project in Exhibit 2, Tab 3, Schedule 1.

The working capital allowance increased by $84,350 from the 2008 Bridge Year. A detailed calculation of the working capital allowance for the 2009 Test Year can be found at Exhibit 2, Tab 4, Schedule 1.

GROSS ASSETS – PROPERTY, PLANT, EQUIPMENT & ACCUMULATED DEPRECIATION

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

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land - Substations	283,350.00			283,350.00				0.00	283,350.00
47	1808	Buildings - Substations				0.00				0.00	0.00
13	1810	Leasehold Improvements	86,252.00			86,252.00	20,700.00	3,450.00		24,150.00	62,102.00
47	1815	Transformer Station Equipment > 50 kV				0.00				0.00	0.00
47	1820	Substation Equipment	2,929,319.83	1,301,539.21		4,230,859.04	1,730,782.00	121,116.33		1,851,898.33	2,378,960.71
47	1825	Storage Battery Equipment				0.00				0.00	0.00
47	1830	Poles, Towers & Fixtures	5,492,194.12	316,466.14		5,808,660.26	2,703,198.41	225,483.00		2,928,681.41	2,879,978.85
47	1835	OH Conductors & Devices	7,923,307.14	377,156.75		8,300,463.89	4,967,672.64	318,607.33		5,286,279.97	3,014,183.92
47	1840	UG Conduit	1,565,088.46	162,005.44		1,727,093.90	664,780.74	65,843.00		730,623.74	996,470.16
47	1845	UG Conductors & Devices	5,598,485.93	230,499.33		5,828,985.26	2,515,380.29	226,060.80		2,741,441.09	3,087,544.17
47	1850	Line Transformers	6,505,132.85	464,622.65	4,578.60	6,965,176.90	3,802,027.27	274,824.89	4,578.60	4,072,273.56	2,892,903.34
47	1855	Services (OH & UG)	2,623,680.54	317,388.71		2,941,069.25	955,399.21	110,695.00		1,066,094.21	1,874,975.04
47	1860	Meters	1,746,770.07	67,097.77	28,172.58	1,785,695.26	1,055,687.79	65,057.94	28,172.58	1,092,573.15	693,122.11
47	1861	Smart Meters				0.00				0.00	0.00
N/A	1905	Land	201,049.00			201,049.00				0.00	201,049.00
CEC	1806	Land Rights	951,556.30	630.00		952,186.30	456,801.00	19,037.00		475,838.00	476,348.30
47	1908	Buildings & Fixtures	514,289.73	50,036.04		564,325.77	116,590.00	21,572.00		138,162.00	426,163.77
13	1910	Leasehold Improvements				0.00				0.00	0.00
8	1915	Office Furniture & Equipment	226,891.11	6,628.97		233,520.08	147,233.10	15,204.42		162,437.52	71,082.56
10	1920	Computer - Hardware	513,895.39			513,895.39	440,527.39	27,102.86		467,630.25	46,265.14
45	1921	Computer - Hardware post Mar 22/04	20,739.00	65,315.60		86,054.60	4,666.00	10,679.40		15,345.40	70,709.20
50	1921	Computer - Hardware post Mar19/07				0.00				0.00	0.00
12	1925	Computer - Software	528,843.35	72,091.44		600,934.79	410,776.41	70,691.36		481,467.77	119,467.02
10	1930	Transportation Equipment	271,016.34	35,826.64		306,842.98	185,363.95	24,132.00		209,495.95	97,347.03
8	1935	Stores Equipment	14,741.36	671.58		15,412.94	10,640.93	1,100.81		11,741.74	3,671.20
8	1940	Tools, Shop & Garage Equipment	134,968.46	8,126.88		143,095.34	122,386.25	4,139.04		126,525.29	16,570.05
8	1945	Measurement & Testing Equipment	8,826.78			8,826.78	3,745.00	883.00		4,628.00	4,198.78
8	1950	Power operated Equipment				0.00				0.00	0.00
8	1955	Communications Equipment				0.00				0.00	0.00
8	1960	Miscellaneous Equipment				0.00				0.00	0.00
47	1965	Water Heater Rental Units				0.00				0.00	0.00
47	1970	Load Management controls				0.00				0.00	0.00
47	1975	Load Management Controls Utility Premises				0.00				0.00	0.00
47	1980	System Supervisory Equipment	1,042,884.46	6,521.90		1,049,406.36	313,269.00	69,742.00		383,011.00	666,395.36
47	1985	Sentinel Lighting Rental Units				0.00				0.00	0.00
47	1996	Hydro One S/S Contribution				0.00				0.00	0.00
47	1995	Contributions & Grants	(2,652,222.01)	(1,020,015.26)		(3,672,237.27)	(383,943.00)	(126,488.01)		(510,431.01)	(3,161,806.26)
		Total before Work in Process	**36,531,060.21**	**2,462,609.79**	**32,751.18**	**38,960,918.82**	**20,243,684.38**	**1,548,934.17**	**32,751.18**	**21,759,867.37**	**17,201,051.45**
WIP		Work in Process				0.00	0.00	0.00	0.00	0.00	0.00
		Total after Work in Process	**36,531,060.21**	**2,462,609.79**	**32,751.18**	**38,960,918.82**	**20,243,684.38**	**1,548,934.17**	**32,751.18**	**21,759,867.37**	**17,201,051.45**

Table 2
Innisfil Hydro Distribution Systems Ltd. - Distribution & Operations
Fixed Asset Continuity Schedule
As at December 31, 2007

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land - Substations	283,350.00			283,350.00	0.00			0.00	283,350.00
47	1808	Buildings - Substations	0.00			0.00	0.00			0.00	0.00
13	1810	Leasehold Improvements	86,252.00			86,252.00	24,150.00	3,450.00		27,600.00	58,652.00
47	1815	Transformer Station Equipment > 50 kV	0.00			0.00	0.00			0.00	0.00
47	1820	Substation Equipment	4,230,859.04	28,374.89		4,259,233.93	1,851,898.33	137,459.00		1,989,357.33	2,269,876.60
47	1825	Storage Battery Equipment	0.00			0.00	0.00			0.00	0.00
47	1830	Poles, Towers & Fixtures	5,808,660.26	315,056.59		6,123,716.85	2,928,681.41	238,180.20		3,166,861.61	2,956,855.24
47	1835	OH Conductors & Devices	8,300,463.89	689,240.25		8,989,704.14	5,286,279.97	339,937.88		5,626,217.85	3,363,486.29
47	1840	UG Conduit	1,727,093.90	20,402.96		1,747,496.86	730,623.74	69,491.00		800,114.74	947,382.12
47	1845	UG Conductors & Devices	5,828,985.26	45,253.66		5,874,238.92	2,741,441.09	231,575.80		2,973,016.89	2,901,222.03
47	1850	Line Transformers	6,965,176.90	313,722.76	12,376.00	7,266,523.66	4,072,273.56	290,233.89	12,376.00	4,350,131.45	2,916,392.21
47	1855	Services (OH & UG)	2,941,069.25	240,088.68		3,181,157.93	1,066,094.21	121,846.00		1,187,940.21	1,993,217.72
47	1860	Meters	1,785,695.26	44,196.37	24,707.04	1,805,184.59	1,092,573.15	73,822.64	24,707.04	1,141,688.75	663,495.84
47	1861	Smart Meters	0.00			0.00	0.00			0.00	0.00
N/A	1905	Land	201,049.00			201,049.00	0.00			0.00	201,049.00
CEC	1806	Land Rights	952,186.30	3,840.73		956,027.03	475,838.00	19,082.92		494,920.92	461,106.11
47	1908	Buildings & Fixtures	564,325.77	43,035.99		607,361.76	138,162.00	23,433.00		161,595.00	445,766.76
13	1910	Leasehold Improvements	0.00			0.00	0.00			0.00	0.00
8	1915	Office Furniture & Equipment	233,520.08	13,874.61		247,394.69	162,437.52	15,137.00		177,574.52	69,820.17
10	1920	Computer - Hardware	513,895.39			513,895.39	467,630.25	18,506.03		486,136.28	27,759.11
45	1921	Computer - Hardware post Mar 22/04	86,054.60	23,199.63		109,254.23	15,345.40	22,721.06		38,066.46	71,187.77
50	1921	Computer - Hardware post Mar19/07	0.00	85,153.00		85,153.00	0.00	8,515.00		8,515.00	76,638.00
12	1925	Computer - Software	600,934.79	173,995.06		774,929.85	481,467.77	95,377.85		576,845.62	198,084.23
10	1930	Transportation Equipment	306,842.98	34,820.40		341,663.38	209,495.95	27,714.00		237,209.95	104,453.43
8	1935	Stores Equipment	15,412.94	560.79		15,973.73	11,741.74	940.07		12,681.81	3,291.92
8	1940	Tools, Shop & Garage Equipment	143,095.34	6,541.10		149,636.44	126,525.29	3,909.83		130,435.12	19,201.32
8	1945	Measurement & Testing Equipment	8,826.78	6,275.47		15,102.25	4,628.00	1,197.00		5,825.00	9,277.25
8	1950	Power operated Equipment	0.00			0.00	0.00			0.00	0.00
8	1955	Communications Equipment	0.00			0.00	0.00			0.00	0.00
8	1960	Miscellaneous Equipment	0.00			0.00	0.00			0.00	0.00
47	1965	Water Heater Rental Units	0.00			0.00	0.00			0.00	0.00
47	1970	Load Management controls	0.00			0.00	0.00			0.00	0.00
47	1975	Load Management Controls Utility Premises	0.00			0.00	0.00			0.00	0.00
47	1980	System Supervisory Equipment	1,049,406.36	40,209.05		1,089,615.41	383,011.00	71,301.00		454,312.00	635,303.41
47	1985	Sentinel Lighting Rental Units	0.00			0.00	0.00			0.00	0.00
47	1996	Hydro One S/S Contribution	0.00			0.00	0.00			0.00	0.00
47	1995	Contributions & Grants	(3,672,237.27)	(642,593.53)		(4,314,830.80)	(510,431.01)	(148,237.00)		(658,668.01)	(3,656,162.79)
		Total before Work in Process	**38,960,918.82**	**1,485,248.46**	**37,083.04**	**40,409,084.24**	**21,759,867.37**	**1,665,594.17**	**37,083.04**	**23,388,378.50**	**17,020,705.74**
WIP		Work in Process	0.00			0.00	0.00	0.00	0.00	0.00	0.00
		Total after Work in Process	**38,960,918.82**	**1,485,248.46**	**37,083.04**	**40,409,084.24**	**21,759,867.37**	**1,665,594.17**	**37,083.04**	**23,388,378.50**	**17,020,705.74**

Table 3
Innisfil Hydro - Distribution & Operations
Fixed Asset Continuity Schedule
2008 Bridge Year

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land - Substations	283,350.00			283,350.00	0.00			0.00	283,350.00
47	1808	Buildings - Substations	0.00			0.00	0.00			0.00	0.00
13	1810	Leasehold Improvements	86,252.00			86,252.00	27,600.00	3,450.00		31,050.00	55,202.00
47	1815	Transformer Station Equipment > 50 kV	0.00			0.00	0.00			0.00	0.00
47	1820	Substation Equipment	4,259,233.93	58,850.00		4,318,083.93	1,989,357.33	138,913.00		2,128,270.33	2,189,813.60
47	1825	Storage Battery Equipment	0.00			0.00	0.00			0.00	0.00
47	1830	Poles, Towers & Fixtures	6,123,716.85	910,360.00		7,034,076.85	3,166,861.61	262,752.00		3,429,613.61	3,604,463.24
47	1835	OH Conductors & Devices	8,989,704.14	812,800.00		9,802,504.14	5,626,217.85	369,976.00		5,996,193.85	3,806,310.29
47	1840	UG Conduit	1,747,496.86	20,850.00		1,768,346.86	800,114.74	70,316.00		870,430.74	897,916.12
47	1845	UG Conductors & Devices	5,874,238.92	835,650.00		6,709,888.92	2,973,016.89	249,192.00		3,222,208.89	3,487,680.03
47	1850	Line Transformers	7,266,523.66	525,950.00	8,011.00	7,784,462.66	4,350,131.45	306,780.00	8,011.00	4,648,900.45	3,135,562.21
47	1855	Services (OH & UG)	3,181,157.93	255,700.00		3,436,857.93	1,187,940.21	131,760.00		1,319,700.21	2,117,157.72
47	1860	Meters	1,805,184.59	80,000.00	28,480.00	1,856,704.59	1,141,688.75	76,804.00	28,480.00	1,190,012.75	666,691.84
47	1861	Smart Meters	0.00			0.00	0.00			0.00	0.00
N/A	1905	Land	201,049.00			201,049.00	0.00			0.00	201,049.00
CEC	1806	Land Rights	956,027.03	15,500.00		971,527.03	494,920.92	19,275.00		514,195.92	457,331.11
47	1908	Buildings & Fixtures	607,361.76	85,000.00		692,361.76	161,595.00	25,993.00		187,588.00	504,773.76
13	1910	Leasehold Improvements	0.00			0.00	0.00			0.00	0.00
8	1915	Office Furniture & Equipment	247,394.69	19,600.00		266,994.69	177,574.52	14,938.00		192,512.52	74,482.17
10	1920	Computer - Hardware	513,895.39			513,895.39	486,136.28	18,506.00		504,642.28	9,253.11
45	1921	Computer - Hardware post Mar 22/04	109,254.23			109,254.23	38,066.46	18,457.00		56,523.46	52,730.77
50	1921	Computer - Hardware post Mar 19/07	85,153.00	60,500.00		145,653.00	8,515.00	23,080.00		31,595.00	114,058.00
12	1925	Computer - Software	774,929.85	90,400.00		865,329.85	576,845.62	114,137.00		690,982.62	174,347.23
10	1930	Transportation Equipment	341,663.38	38,000.00	48,822.00	330,841.38	237,209.95	30,730.00	48,822.00	219,117.95	111,723.43
8	1935	Stores Equipment	15,973.73	3,500.00		19,473.73	12,681.81	624.00		13,305.81	6,167.92
8	1940	Tools, Shop & Garage Equipment	149,636.44	9,000.00		158,636.44	130,435.12	3,881.00		134,316.12	24,320.32
8	1945	Measurement & Testing Equipment	15,102.25	2,000.00		17,102.25	5,825.00	1,611.00		7,436.00	9,666.25
8	1950	Power operated Equipment	0.00			0.00	0.00			0.00	0.00
8	1955	Communications Equipment	0.00			0.00	0.00			0.00	0.00
8	1960	Miscellaneous Equipment	0.00			0.00	0.00			0.00	0.00
47	1965	Water Heater Rental Units	0.00			0.00	0.00			0.00	0.00
47	1970	Load Management controls	0.00			0.00	0.00			0.00	0.00
47	1975	Load Management Controls Utility Premises	0.00			0.00	0.00			0.00	0.00
47	1980	System Supervisory Equipment	1,089,615.41	123,900.00		1,213,515.41	454,312.00	76,772.00		531,084.00	682,431.41
47	1985	Sentinel Lighting Rental Units	0.00			0.00	0.00			0.00	0.00
47	1996	Hydro One S/S Contribution	0.00			0.00	0.00			0.00	0.00
47	1995	Contributions & Grants	(4,314,830.80)	(505,000.00)	0.00	(4,819,830.80)	(658,668.01)	(182,692.00)		(841,360.01)	(3,978,470.79)
		Total before Work in Process	**40,409,084.24**	**3,442,560.00**	**85,313.00**	**43,766,331.24**	**23,388,378.50**	**1,775,255.00**	**85,313.00**	**25,078,320.50**	**18,688,010.74**
WIP		Work in Process	0.00			0.00	0.00			0.00	0.00
		Total after Work in Process	**40,409,084.24**	**3,442,560.00**	**85,313.00**	**43,766,331.24**	**23,388,378.50**	**1,775,255.00**	**85,313.00**	**25,078,320.50**	**18,688,010.74**

Table 4 Innisfil Hydro - Distribution & Operations
Fixed Asset Continuity Schedule
2009 Test Year

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land - Substations	283,350.00			283,350.00	0.00			0.00	283,350.00
47	1808	Buildings - Substations	0.00			0.00	0.00			0.00	0.00
13	1810	Leasehold Improvements	86,252.00			86,252.00	31,050.00	3,450.00		34,500.00	51,752.00
47	1815	Transformer Station Equipment > 50 kV	0.00			0.00	0.00			0.00	0.00
47	1820	Substation Equipment	4,318,083.93	235,900.00		4,553,983.93	2,128,270.33	143,825.00		2,272,095.33	2,281,888.60
47	1825	Storage Battery Equipment	0.00			0.00	0.00			0.00	0.00
47	1830	Poles, Towers & Fixtures	7,034,076.85	1,644,636.00		8,678,712.85	3,429,613.61	313,866.00		3,743,479.61	4,935,233.24
47	1835	OH Conductors & Devices	9,802,504.14	2,693,107.00		12,495,611.14	5,996,193.85	440,094.00		6,436,287.85	6,059,323.29
47	1840	UG Conduit	1,768,346.86	23,000.00		1,791,346.86	870,430.74	71,193.00		941,623.74	849,723.12
47	1845	UG Conductors & Devices	6,709,888.92	868,150.00		7,578,038.92	3,222,208.89	283,268.00		3,505,476.89	4,072,562.03
47	1850	Line Transformers	7,784,462.66	771,293.00	8,171.00	8,547,584.66	4,648,900.45	332,789.00	8,171.00	4,973,518.45	3,574,066.21
47	1855	Services (OH & UG)	3,436,857.93	322,705.00		3,759,562.93	1,319,700.21	143,301.00		1,463,001.21	2,296,561.72
47	1860	Meters	1,856,704.59	4,000.00	29,049.00	1,831,655.59	1,190,012.75	76,788.00	29,049.00	1,237,751.75	593,903.84
47	1861	Smart Meters	0.00			0.00	0.00			0.00	0.00
N/A	1905	Land	201,049.00			201,049.00	0.00			0.00	201,049.00
CEC	1806	Land Rights	971,527.03	21,500.00		993,027.03	514,195.92	19,464.00		533,659.92	459,367.11
47	1908	Buildings & Fixtures	692,361.76	25,000.00		717,361.76	187,588.00	28,193.00		215,781.00	501,580.76
13	1910	Leasehold Improvements	0.00			0.00	0.00			0.00	0.00
8	1915	Office Furniture & Equipment	266,994.69	15,000.00		281,994.69	192,512.52	12,644.00		205,156.52	76,838.17
10	1920	Computer - Hardware	513,895.39			513,895.39	504,642.28	9,253.04		513,895.32	0.07
45	1921	Computer - Hardware post Mar 22/04	109,254.23			109,254.23	56,523.46	21,850.86		78,374.32	30,879.91
50	1921	Computer - Hardware post Mar 19/07	145,653.00	95,000.00		240,653.00	31,595.00	36,245.10		67,840.10	172,812.90
12	1925	Computer - Software	865,329.85	107,500.00		972,829.85	690,982.62	118,065.00		809,047.62	163,782.23
10	1930	Transportation Equipment	330,841.38	76,000.00	49,261.00	357,580.38	219,117.95	38,132.00	49,261.00	207,988.95	149,591.43
8	1935	Stores Equipment	19,473.73	3,700.00		23,173.73	13,305.81	984.00		14,289.81	8,883.92
8	1940	Tools, Shop & Garage Equipment	158,636.44	9,500.00		168,136.44	134,316.12	3,786.00		138,102.12	30,034.32
8	1945	Measurement & Testing Equipment	17,102.25	8,000.00		25,102.25	7,436.00	2,111.00		9,547.00	15,555.25
8	1950	Power operated Equipment	0.00			0.00	0.00			0.00	0.00
8	1955	Communications Equipment	0.00			0.00	0.00			0.00	0.00
8	1960	Miscellaneous Equipment	0.00			0.00	0.00			0.00	0.00
47	1965	Water Heater Rental Units	0.00			0.00	0.00			0.00	0.00
47	1970	Load Management controls	0.00			0.00	0.00			0.00	0.00
47	1975	Load Management Controls Utility Premises	0.00			0.00	0.00			0.00	0.00
47	1980	System Supervisory Equipment	1,213,515.41	145,800.00		1,359,315.41	531,084.00	85,762.00		616,846.00	742,469.41
47	1985	Sentinel Lighting Rental Units	0.00			0.00	0.00			0.00	0.00
47	1996	Hydro One S/S Contribution	0.00			0.00	0.00			0.00	0.00
47	1995	Contributions & Grants	(4,819,830.80)	(571,900.00)		(5,391,730.80)	(841,360.01)	(204,230.00)		(1,045,590.01)	(4,346,140.79)
		Total before Work in Process	**43,766,331.24**	**6,497,891.00**	**86,481.00**	**50,177,741.24**	**25,078,320.50**	**1,980,834.00**	**86,481.00**	**26,972,673.50**	**23,205,067.74**
WIP		Work in Process	0.00			0.00	0.00			0.00	0.00
		Total after Work in Process	**43,766,331.24**	**6,497,891.00**	**86,481.00**	**50,177,741.24**	**25,078,320.50**	**1,980,834.00**	**86,481.00**	**26,972,673.50**	**23,205,067.74**

GROSS ASSETS TABLE:

Gross Assets – Table

Description	2006 Board Approved ($)	2006 Actual ($)	Variance from 2006 Board Approved	2007 Actual ($)	Variance from 2006 Actual	2008 Bridge ($)	Variance from 2007 Bridge	2009 Test ($)	Variance from 2008 Bridge
Land and Buildings									
1805-Land	283,350	283,350		283,350		283,350		283,350	
1806-Land Rights	950,073	952,186	2,113	956,027	3,841	971,527	15,500	993,027	21,500
1808-Buildings and Fixtures									
1905-Land	201,049	201,049		201,049		201,049		201,049	
1906-Land Rights									
1810-Leasehold Improvements	86,252	86,252		86,252		86,252		86,252	
Sub-Total-Land and Buildings	**1,520,724**	**1,522,837**	**2,113**	**1,526,678**	**3,841**	**1,542,178**	**15,500**	**1,563,678**	**21,500**
TS Primary Above 50									
1815-Transformer Station Equipment - Normally Primary above 50 kV									
Sub-Total-TS Primary Above 50									
DS									
1820-Distribution Station Equipment - Normally Primary below 50 kV	2,782,633	4,230,859	1,448,226	4,259,234	28,375	4,318,084	58,850	4,553,984	235,900
Sub-Total-DS	**2,782,633**	**4,230,859**	**1,448,226**	**4,259,234**	**28,375**	**4,318,084**	**58,850**	**4,553,984**	**235,900**
Poles and Wires									
1830-Poles, Towers and Fixtures	5,164,925	5,808,660	643,735	6,123,717	315,057	7,034,077	910,360	8,678,713	1,644,636
1835-Overhead Conductors and Devices	7,504,802	8,300,464	795,662	8,989,704	689,240	9,802,504	812,800	12,495,611	2,693,107
1840-Underground Conduit		1,727,094	1,727,094	1,747,497	20,403	1,768,347	20,850	1,791,347	23,000
1845-Underground Conductors and Devices	7,106,325	5,828,985	(1,277,340)	5,874,239	45,254	6,709,889	835,650	7,578,039	868,150
Sub-Total-Poles and Wires	**19,776,052**	**21,665,203**	**1,889,151**	**22,735,157**	**1,069,953**	**25,314,817**	**2,579,660**	**30,543,710**	**5,228,893**
Line Transformers									
1850-Line Transformers	6,249,141	6,965,177	716,036	7,266,524	301,347	7,784,463	517,939	8,547,585	763,122
Sub-Total-Line Transformers	**6,249,141**	**6,965,177**	**716,036**	**7,266,524**	**301,347**	**7,784,463**	**517,939**	**8,547,585**	**763,122**
Services and Meters									
1855-Services	2,333,575	2,941,069	607,494	3,181,158	240,089	3,436,858	255,700	3,759,563	322,705
1860-Meters	1,767,530	1,785,695	18,165	1,805,185	19,489	1,856,705	51,520	1,831,656	(25,049)
1861-Smart Meters									
Sub-Total-Services and Meters	**4,101,105**	**4,726,765**	**625,660**	**4,986,343**	**259,578**	**5,293,563**	**307,220**	**5,591,219**	**297,656**
General Plant									
1908-Buildings and Fixtures	501,504	564,326	62,822	607,362	43,036	692,362	85,000	717,362	25,000
1910-Leasehold Improvements									
Sub-Total-General Plant	**501,504**	**564,326**	**62,822**	**607,362**	**43,036**	**692,362**	**85,000**	**717,362**	**25,000**
IT Assets									
1920-Computer Equipment - Hardware	458,821	513,895	55,074	513,895		513,895		513,895	
1921-Computer Equipment - Hardware post March 22, 2004	20,739	86,055	65,316	194,407	108,353	254,907	60,500	349,907	95,000
1925-Computer Software	401,799	600,935	199,136	774,930	173,995	865,330	90,400	972,830	107,500
Sub-Total-IT Assets	**881,359**	**1,200,885**	**319,526**	**1,483,232**	**282,348**	**1,634,132**	**150,900**	**1,836,632**	**202,500**
Equipment									
1915-Office Furniture and Equipment	188,737	233,520	44,783	247,395	13,875	266,995	19,600	281,995	15,000
1930-Transportation Equipment	185,313	306,843	121,530	341,663	34,820	330,841	(10,822)	357,580	26,739
1935-Stores Equipment	12,782	15,413	2,631	15,974	561	19,474	3,500	23,174	3,700
1940-Tools, Shop and Garage Equipment	132,924	143,095	10,171	149,636	6,541	158,636	9,000	168,136	9,500
1945-Measurement and Testing Equipment	8,720	8,827	107	15,102	6,275	17,102	2,000	25,102	8,000
1950-Power Operated Equipment									
1955-Communication Equipment									
1960-Miscellaneous Equipment									
Sub-Total-Equipment	**528,476**	**707,698**	**179,222**	**769,770**	**62,072**	**793,048**	**23,278**	**855,987**	**62,939**
Other Distribution Assets									
1825-Storage Battery Equipment									
1970-Load Management Controls - Customer Premises									
1975-Load Management Controls - Utility Premises									
1980-System Supervisory Equipment	941,657	1,049,406	107,749	1,089,615	40,209	1,213,515	123,900	1,359,315	145,800
1985-Sentinel Lighting Rental Units									
1990-Other Tangible Property									
1995-Contributions and Grants - Credit	(2,224,487)	(3,672,237)	(1,447,750)	(4,314,831)	(642,594)	(4,819,831)	(505,000)	(5,391,731)	(571,900)
1996-Hydro One S/S Contribution									
Sub-Total-Other Distribution Assets	**(1,282,830)**	**(2,622,831)**	**(1,340,001)**	**(3,225,215)**	**(602,384)**	**(3,606,315)**	**(381,100)**	**(4,032,415)**	**(426,100)**
GROSS ASSET TOTAL	35,058,164	38,960,919	3,902,755	40,409,084	1,448,165	43,766,331	3,357,247	50,177,741	6,411,410

MATERIALITY ANALYSIS ON GROSS ASSETS

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

Gross Asset Materiality
Table 1

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Bridge Year	2009 Test Year
Gross Fixed Assets	$35,058,164	$ 38,960,919	$40,409,084	$43,766,331	$50,177,741
Accumulated Depreciation	$18,087,071	$ 21,759,867	$23,388,379	$25,078,321	$26,972,674
Net Book Value	$16,971,093	$ 17,201,051	$17,020,706	$18,688,011	$23,205,068
Variance calc 1% NBV		$ 172,011	$170,207	$186,880	$232,051

Innisfil Hydro has selected the lowest materiality threshold of $170,000 to provide the benchmark of detail review of gross asset changes.

ACCUMULATED DEPRECIATION:

Table 1
Accumulated Depreciation

Description	2006 Board Approved ($)	2006 Actual ($)	Variance from 2006 Board Approved	2007 Actual ($)	Variance from 2006 Actual	2008 Bridge ($)	Variance from 2007 Bridge	2009 Test ($)	Variance from 2008 Bridge
Land and Buildings									
1805-Land									
1806-Land Rights	428,268	475,838	47,570	494,921	19,083	514,196	19,275	533,660	19,464
1808-Buildings and Fixtures									
1905-Land									
1906-Land Rights									
1810-Leasehold Improvements	15,525	24,150	8,625	27,600	3,450	31,050	3,450	34,500	3,450
Sub-Total-Land and Buildings	**443,793**	**499,988**	**56,195**	**522,521**	**22,533**	**545,246**	**22,725**	**568,160**	**22,914**
TS Primary Above 50									
1815-Transformer Station Equipment - Normally Primary above 50 kV									
Sub-Total-TS Primary Above 50									
DS									
1820-Distribution Station Equipment - Normally Primary below 50 kV	1,598,267	1,851,898	253,631	1,989,357	137,459	2,128,270	138,913	2,272,095	143,825
Sub-Total-DS	**1,598,267**	**1,851,898**	**253,631**	**1,989,357**	**137,459**	**2,128,270**	**138,913**	**2,272,095**	**143,825**
Poles and Wires									
1830-Poles, Towers and Fixtures	2,385,639	2,928,681	543,042	3,166,862	238,180	3,429,614	262,752	3,743,480	313,866
1835-Overhead Conductors and Devices	4,512,824	5,286,280	773,456	5,626,218	339,938	5,996,194	369,976	6,436,288	440,094
1840-Underground Conduit	602,354	730,624	128,270	800,115	69,491	870,431	70,316	941,624	71,193
1845-Underground Conductors and Devices	2,151,229	2,741,441	590,212	2,973,017	231,576	3,222,209	249,192	3,505,477	283,268
Sub-Total-Poles and Wires	**9,652,046**	**11,687,026**	**2,034,980**	**12,566,211**	**879,185**	**13,518,447**	**952,236**	**14,626,868**	**1,108,421**
Line Transformers									
1850-Line Transformers	3,428,277	4,072,274	643,997	4,350,131	277,858	4,648,900	298,769	4,973,518	324,618
Sub-Total-Line Transformers	**3,428,277**	**4,072,274**	**643,997**	**4,350,131**	**277,858**	**4,648,900**	**298,769**	**4,973,518**	**324,618**
Services and Meters									
1855-Services	807,999	1,066,094	258,095	1,187,940	121,846	1,319,700	131,760	1,463,001	143,301
1860-Meters	987,601	1,092,573	104,972	1,141,689	49,116	1,190,013	48,324	1,237,752	47,739
1861-Smart Meters									
Sub-Total-Services and Meters	**1,795,600**	**2,158,667**	**363,067**	**2,329,629**	**170,962**	**2,509,713**	**180,084**	**2,700,753**	**191,040**
General Plant									
1908-Buildings and Fixtures	86,148	138,162	52,014	161,595	23,433	187,588	25,993	215,781	28,193
1910-Leasehold Improvements									
Sub-Total-General Plant	**86,148**	**138,162**	**52,014**	**161,595**	**23,433**	**187,588**	**25,993**	**215,781**	**28,193**
IT Assets									
1920-Computer Equipment - Hardware	389,199	467,630	78,431	486,136	18,506	504,642	18,506	513,895	9,253
1921-Computer Equipment - Hardware post March 22, 2004	4,666	15,345	10,679	46,581	31,236	88,118	41,537	146,214	58,096
1925-Computer Software	298,647	481,468	182,821	576,846	95,378	690,983	114,137	809,048	118,065
Sub-Total-IT Assets	**692,512**	**964,443**	**271,931**	**1,109,563**	**145,120**	**1,283,743**	**174,180**	**1,469,157**	**185,414**
Equipment									
1915-Office Furniture and Equipment	126,772	162,438	35,666	177,575	15,137	192,513	14,938	205,157	12,644
1930-Transportation Equipment	166,795	209,496	42,701	237,210	27,714	219,118	(18,092)	207,989	(11,129)
1935-Stores Equipment	9,167	11,742	2,575	12,682	940	13,306	624	14,290	984
1940-Tools, Shop and Garage Equipment	109,627	126,525	16,898	130,435	3,910	134,316	3,881	138,102	3,786
1945-Measurement and Testing Equipment	2,448	4,628	2,180	5,825	1,197	7,436	1,611	9,547	2,111
1950-Power Operated Equipment									
1955-Communication Equipment									
1960-Miscellaneous Equipment									
Sub-Total-Equipment	**414,809**	**514,829**	**100,020**	**563,726**	**48,898**	**566,688**	**2,962**	**575,084**	**8,396**
Other Distribution Assets									
1825-Storage Battery Equipment									
1970-Load Management Controls - Customer Premises									
1975-Load Management Controls - Utility Premises									
1980-System Supervisory Equipment	213,947	383,011	169,064	454,312	71,301	531,084	76,772	616,846	85,762
1985-Sentinel Lighting Rental Units									
1990-Other Tangible Property									
1995-Contributions and Grants - Credit	(238,327)	(510,431)	(272,104)	(658,668)	(148,237)	(841,360)	(182,692)	(1,045,590)	(204,230)
1996-Hydro One S/S Contribution									
Sub-Total-Other Distribution Assets	**(24,380)**	**(127,420)**	**(103,040)**	**(204,356)**	**(76,936)**	**(310,276)**	**(105,920)**	**(428,744)**	**(118,468)**
ACCUMULATED DEPRICIATION TOTAL	18,087,072	21,759,867	3,672,795	23,388,379	1,628,511	25,078,321	1,689,942	26,972,674	1,894,353

VARIANCE ANALYSIS ON ACCUMULATED DEPRECIATION:

Changes in accumulated depreciation are directly affected by changes in fixed assets due to additions, the removal of fully depreciated assets from the grouped asset classes, and the disposition of identifiable assets. The 2006 Board Approved closing balance for accumulated depreciation is based on the average of Innisfil Hydro’s 2003 and 2004 year end account balances, plus Tier 1 capital adjustments approved in Innisfil Hydro’s 2006 EDR Application. As such, the variance between 2006 Board Approved and 2006 Actual represents an averaging effect and two years of depreciation changes. Depreciation is written on a straight line basis using ½ rate for the first year in service in accordance with Article 510 of the APH.

The following page provides a listing and description of Fixed Asset accounts including Contributed Capital, their estimated useful lives, and the depreciation rate currently provided in the OEB Accounting Procedures Handbook.

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	25	4
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	5	20
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

CAPITAL BUDGET

Overview and Capital Budget by Project:

Innisfil Hydro has been, and continues to be, focused on maintaining the adequacy, reliability and quality of service to its distribution customers.

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

The capital budget process is a component of the overall budget process described in Exhibit 2, Tab 1, Schedule 1, above.

- **Capital Work plans:**

Each department Director is responsible for the preparation of the departmental capital budget. The following directives are provided to each Director:

- All department budgets are to be built using a "bottom up" approach, which requires each functional area within Innisfil Hydro to build work plans that identify resources, including labour, vehicles, materials and other third party costs that are required to execute the work plans. This approach ensures that budgets are developed based on the actual work to be completed during the fiscal year, as opposed to a historical costing approach.
- Where applicable, Activity Based Costing ("ABC") work order methodology is to be used in the creation of work plans.
- Budgets are to be supported by documented assumptions.

- **Project Capital Budget Plan:**

Once all projects have been identified, they are evaluated against certain criteria in the AMP in order to affect a relative ranking of projects. Decisions on priorities are made to include those projects determined to be the most important within a level of affordability and evaluated by the Director responsible for the applicable area. A final budget package is produced to present to the Executive Team for their review and approval.

The subsequent actual-to-budget review process is outlined in the overall budget process, discussed at Exhibit 2, Tab 1, Schedule 1, above.

The following two tables summarize Innisfil Hydro's historical and projected capital budget expenditures by USofA and key Categories. Table 1 provides capital expenditures in the General Leger Account format. Table 2 provides a breakdown of the Distribution and General Plant Expenditures by categories called Key Categories.

CAPITAL EXPENDITURES BY GENERAL LEDGER ACCOUNT 2005 TO 2009

Table 1

2005 Distribution Plant Expenditures

Category	Project Description	Total Project	Acct 1806	Acct 1820	Acct 1830	Acct 1835	Acct 1840	Acct 1845	Acct 1850	Acct 1855	Acct 1860
Infrastructure	Pole replacement 10 SR to Hwy 11	166,443			76,968	87,067			2,408		
Reliability	Guard rails	34,592			34,592						
Infrastructure	Pole replacement 44 kV	36,938			19,553	17,385					
Infrastructure	Pole replacement 25th SR	28,387			7,343	21,044					
Cust Demand	Emmanual Church u/g primary service	32,402			1,854	1,766			15,853	12,929	
Metering	Miscellaneous customer metering	71,008									71,008
Cust Demand	Miscellaneous customer demand	456,246			38,191	86,813		36,178	147,345	147,719	
Infrastructure	Miscellaneous infrastucture	182,274			38,191	86,813		4,020	36,837	16,413	
Substation	Substation investments	4,506		4,506							
	Total Distribution Plant Expenditures	**1,012,796**	**-**	**4,506**	**216,692**	**300,888**	**-**	**40,198**	**202,443**	**177,061**	**71,008**

2005 General Plant Expenditures

Category	Project Description	Total Project	Acct 1908	Acct 1915	Acct 1920	Acct 1925	Acct 1930	Acct 1935	Acct 1940	Acct 1945	Acct 1980
Facilities	Building fixtures & renos	7,923	7,923								
Facilities	Office equip-copier, mailing mach	25,524		25,524							
Computer	Hardware-pc's & printers	20,739			20,739						
Computer	Software-Great Plains & GIS upgrades etc	102,254				102,254					
Transportation	2 Truck	69,628					69,628				
Communicaton	Scada programming & updates	34,022									34,022
Tools & Equip	Miscellaneous stores equipment	1,360						1,360			
Tools & Equip	Miscellaneous tools & shop equipment	948							948		
Tools & Equip	Miscellaneous testing equipment	427								427	
	Total Distribution Plant Expenditures	**262,825**	**7,923**	**25,524**	**20,739**	**102,254**	**69,628**	**1,360**	**948**	**427**	**34,022**
	Total 2005 Capital Expenditures	**1,275,621**									

2006 Distribution Plant Expenditures

Category	Project Description	Total Project	Acct 1806	Acct 1820	Acct 1830	Acct 1835	Acct 1840	Acct 1845	Acct 1850	Acct 1855	Acct 1860
Cust Demand	Thor School u/g primary service	29,051				4,937			19,452	4,409	253
Infrastructure	Pole replacement	183,057			113,402	59,567			10,088		
Infrastructure	Alcona Voltage Conversion	156,695			19,542	92,196			42,984	1,973	
Capacity	Install LeFroy DS F3 feeder	36,406				9,939		26,467			
Cust Demand	Royal Distributing u/g primary service	38,954			3,655	4,846			17,949	12,222	282
Cust Demand	44 kV line extension	73,540			9,463	56,494			278	7,007	298
Cust Demand	Capitalized Subdivison Assets Transferred	498,556					121,238	179,083	91,306	106,929	
Substation	New Distribution Station	1,301,539		1,301,539							
	UG Conduit accout setup						1,565,089	(1,565,089)			
	Whole meters classification correction	0		127,800							(127,800)
Metering	Miscellaneous customer metering	66,265									66,265
Cust Demand	Miscellaneous customer demand	615,902	472		85,202	74,589	40,767	22,454	226,053	166,365	
Infrastructure	Miscellaneous infrastucture	237,441	158		85,202	74,589		2,495	56,513	18,484	
	Total Distribution Plant Expenditures	**3,237,406**	**630**	**1,429,339**	**316,466**	**377,157**	**1,727,094**	**- 1,334,590**	**464,623**	**317,389**	**- 60,702**

2006 General Plant Expenditures

Category	Project Description	Total Project	Acct 1908	Acct 1915	Acct 1920	Acct 1925	Acct 1930	Acct 1935	Acct 1940	Acct 1945	Acct 1980
Facilities	Paving	33,900	33,900								
Facilities	Building fixtures & renos	16,135	16,135								
Facilities	Office equip-cabinets, furniture	6,629		6,629							
Computer	Hardware-servers, pc's & printers	65,316			65,316						
Computer	Software-Bar coding, Filenexus upgrades e	72,091				72,091					
Transportation	1 Truck	35,827					35,827				
Communicaton	Scada programming & updates	6,522									6,522
Tools & Equip	Miscellaneous stores equipment	672						672			
Tools & Equip	Miscellaneous tools & shop equipment	8,127							8,127		
Tools & Equip	Miscellaneous testing equipment	0								0	
	Total Distribution Plant Expenditures	**245,219**	**50,035**	**6,629**	**65,316**	**72,091**	**35,827**	**672**	**8,127**	**-**	**6,522**
	Total 2006 Capital Expenditures	**3,482,625**									

2007 Distribution Plant Expenditures

Category	Project Description	Total Project	Acct 1806	Acct 1820	Acct 1830	Acct 1835	Acct 1840	Acct 1845	Acct 1850	Acct 1855	Acct 1860
Capacity	9M3 &9M6 double circuit 44 kV extension	35,179			3,531	31,648					
Cust Demand	Pole relocate for entrance into subdivision	50,011			19,701	30,310					
Reliability	Extend 44000 volt subtransmission	210,551			46,335	158,911			5,305		
Cust Demand	Private primary service	19,639			1,819	836			10,065	6,796	123
Cust Demand	Town booster station for water supply	36,905			4,381	4,381			23,762	4,381	
Infrastructure	Alcona voltage conversion	315,260			45,217	173,462			90,987	5,594	
Cust Demand	Road relocate 9 double circuit	131,068			51,018	73,307		2,906	3,837		
Cust Demand	Town Admin building u/g primary service	39,834							28,390	11,143	301
Cust Demand	Subaru car dealership u/g primary service	38,099							33,281	4,601	217
Cust Demand	Mercedez car dealership u/g primary serv	36,023							32,669	3,138	216
Cust Demand	Shell and Tim's u/g primary service	30,250				1,927			23,668	4,366	289
Cust Demand	Woodland Park subdivision	27,152					3,817	10,770	534	12,031	
Metering	Miscellaneous customer metering	43,048									43,048
Cust Demand	Miscellaneous customer demand	444,473	2,881		71,527	107,228	16,586	28,420	52,049	165,782	
Infrastructure	Miscellaneous infrastucture	214,307	960		71,527	107,229		3,158	13,013	18,420	
Substation	Substation investments	28,376		28,376							
	Total Distribution Plant Expenditures	**1,700,175**	**3,841**	**28,376**	**315,056**	**689,239**	**20,403**	**45,254**	**317,560**	**236,252**	**44,194**

2007 General Plant Expenditures

Category	Project Description	Total Project	Acct 1908	Acct 1915	Acct 1920	Acct 1925	Acct 1930	Acct 1935	Acct 1940	Acct 1945	Acct 1980
Facilities	Miscellaneous building fixtures	28,536	28,536								
Facilities	Windows-Customer Service building	14,500	14,500								
Facilities	Office equip-cabinets, furniture	13,875		13,875							
Computer	Hardware-servers, pc's & printers	108,353			108,353						
Computer	Software-Harris, payroll, upgrades etc	173,995				173,995					
Transportation	1 Truck	34,820					34,820				
Communicaton	BD distribution station	5,294									5,294
Communicaton	Scada wide screen	4,198									4,198
Communicaton	Scada programming & updates	30,719									30,719
Tools & Equip	Miscellaneous stores equipment	561						561			
Tools & Equip	Miscellaneous tools & shop equipment	6,541							6,541		
Tools & Equip	Miscellaneous testing equipment	6,275								6,275	
	Total Distribution Plant Expenditures	**427,667**	**43,036**	**13,875**	**108,353**	**173,995**	**34,820**	**561**	**6,541**	**6,275**	**40,211**
	Total 2007 Capital Expenditures	**2,127,842**									

2008 Distribution Plant Expenditures

Category	Project Description	Total Project	Acct 1806	Acct 1820	Acct 1830	Acct 1835	Acct 1840	Acct 1845	Acct 1850	Acct 1855	Acct 1860
Regulatory	Line Ext 15th line	81,900	700		31,100	34,100			16,000		
Security	44 kV line ext BBP	360,400			223,600	128,000			8,800		
Regulatory	Line rebuild Hwy 27	125,800			82,000	36,600			7,200		
Reliability	Guard rails	170,000			170,000						
Cust Demand	Road widening	750,000						750,000			
Reliability	44 kV mechanized Altdi-Ruptor Scada	192,950			16,700	172,600			3,650		
Reliability	27.6 kV mechanized Scada-mate switch	132,750			7,750	125,000					
Infrastructure	Pole replacement	236,510			133,160	67,450			34,100	1,800	
Metering	Industrial Park Road TX	27,000									27,000
Metering	Miscellaneous customer metering	53,000									53,000
Cust Demand	Miscellaneous customer demand	950,055	11,100		123,025	124,525	20,850	77,085	364,960	228,510	
Infrastructure	Miscellaneous infrastucture	376,445	3,700		123,025	124,525		8,565	91,240	25,390	
Substation	Substation investments	58,850		58,850							
	Total Distribution Plant Expenditures	**3,515,660**	**15,500**	**58,850**	**910,360**	**812,800**	**20,850**	**835,650**	**525,950**	**255,700**	**80,000**

2008 General Plant Expenditures

Category	Project Description	Total Project	Acct 1908	Acct 1915	Acct 1920	Acct 1925	Acct 1930	Acct 1935	Acct 1940	Acct 1945	Acct 1980
Facilities	Misc building fixtures and fencing	25,000	25,000								
Facilities	2 Portables	60,000	60,000								
Facilities	Office furniture	19,600		19,600							
Computer	Hardware-servers, pc's & printers	60,500			60,500						
Computer	Software-HR module, upgrades etc	90,400				90,400					
Transportation	1 Trucks	38,000					38,000				
Communicaton	44 kV line ext on BBP	19,600									19,600
Communicaton	44 kV mechanized Altdi-Ruptor Scada	51,000									51,000
Communicaton	27.6 kV mechanized Scada mate switch	9,300									9,300
Communicaton	27.6 kV radio repeated fault indicator	27,000									27,000
Communicaton	Scada programming & updates	17,000									17,000
Tools & Equip	Miscellaneous stores equipment	3,500						3,500			
Tools & Equip	Miscellaneous tools & shop equipment	9,000							9,000		
Tools & Equip	Miscellaneous testing equipment	2,000								2,000	
	Total Distribution Plant Expenditures	**431,900**	**85,000**	**19,600**	**60,500**	**90,400**	**38,000**	**3,500**	**9,000**	**2,000**	**123,900**
	Total 2008 Capital Expenditures	**3,947,560**									

2009 Distribution Plant Expenditures

Category	Project Description	Total Project	Acct 1806	Acct 1820	Acct 1830	Acct 1835	Acct 1840	Acct 1845	Acct 1850	Acct 1855	Acct 1860
Infrastructure	Pole Replacement	271,500			154,000	83,300			34,200		
Reliability	44 kV Load Interrupters	290,540			28,640	261,900					
Infrastructure	Industrial Park Rd Transformer replac	52,200							52,200		
Security	9M4 ext-20 SR 10th line	198,900			68,300	123,550			5,550	1,500	
Reliability	Reclosurer automation	133,900		93,700		40,200					
Cust Demand	Utility relocates	266,900			119,800	117,300			14,600	15,200	
Reliability	27.6 SCADA mates	149,600			11,000	138,600					
Capacity	44 kV line ext 20th SR	389,300			20,900	355,800			7,400	5,200	
Metering	Wholesale meters	140,000									140,000
Reliability	Guard rails	132,900			132,900						
Cust Demand	Road widening	788,800						788,800			
Infrastructure	27 kV voltage conver 20 SR 5th & 6th	184,100			59,000	60,900			64,200		
Capacity	27 kV voltage extension 20 SR 7th & 4th	714,550			399,300	291,900			15,700	7,650	
Infrastructure	Betterment	184,700			13,700	156,000			15,000		
Reliability	Hydro One build double circuit	500,000				500,000					
Reliability	9M3 9M6 extension	853,186	6,500		404,736	406,507			35,443		
Cust Demand	Miscellaneous customer demand	985,860	11,250		116,180	78,575	23,000	71,415	421,600	263,840	
Infrastructure	Miscellaneous infrastucture	341,156	3,750		116,180	78,575		7,935	105,400	29,316	
Substation	Substation investments	2,200		2,200							
Metering	Miscellaneous customer metering	4,000			0						4,000
	Total Distribution Plant Expenditures	**6,584,292**	**21,500**	**95,900**	**1,644,636**	**2,693,107**	**23,000**	**868,150**	**771,293**	**322,706**	**144,000**

2009 General Plant Expenditures

Category	Project Description	Total Project	Acct 1908	Acct 1915	Acct 1920	Acct 1925	Acct 1930	Acct 1935	Acct 1940	Acct 1945	Acct 1980
Facilities	Miscellaneous building fixtures	25,000	25,000								
Facilities	Office equip-copier, scanner etc	15,000		15,000							
Computer	Hardware-servers, pc's & printers	95,000			95,000						
Computer	Software-autocad, upgrades etc	107,500				107,500					
Transportation	2 Trucks	76,000					76,000				
Communicaton	27.6 kV radio fault indicators	38,800									38,800
Communicaton	44 kV load interruptors	33,900									33,900
Communicaton	Recloser automation & replacement	2,500									2,500
Communicaton	Utility relocates	2,500									2,500
Communicaton	27.6kV SCADA mates	10,200									10,200
Communicaton	44 kV line ext	17,200									17,200
Communicaton	New fault indicating & switch devices	18,700									18,700
Communicaton	Scada programming & updates	22,000									22,000
Tools & Equip	Miscellaneous stores equipment	3,700						3,700			
Tools & Equip	Miscellaneous tools & shop equipment	9,500							9,500		
Tools & Equip	Miscellaneous testing equipment	8,000								8,000	
	Total Distribution Plant Expenditures	**485,500**	**25,000**	**15,000**	**95,000**	**107,500**	**76,000**	**3,700**	**9,500**	**8,000**	**145,800**
	Total 2009 Capital Expenditures	**7,069,792**									

CAPITAL EXPENDITURES BY KEY CATEGORY 2006 TO 2009

Table 2

Description	2005 Actual	2006 Actual	2007 Actual	2008 Bridge Year	2009 Test Year
Distribution Plant Projects					
Customer Demand	488,649	1,256,003	853,455	1,700,055	2,041,560
Infrastructure Replace & Betterments	414,041	577,193	529,566	612,955	1,033,656
Security	0	0	0	360,400	198,900
Capacity	0	36,406	35,179	0	1,103,850
Reliability	34,592	0	210,551	495,700	2,060,126
Regulatory Requirements	0	0	0	207,700	0
Substations	4,506	1,301,539	28,376	58,850	2,200
Customer Connections and Metering	71,008	66,265	43,048	80,000	144,000
Sub Total-Distribution Plant Projects	**1,012,796**	**3,237,406**	**1,700,175**	**3,515,660**	**6,584,292**
General Plant Projects					
Facilities	33,447	56,665	56,911	104,600	40,000
Other Computer Hardware and Software	122,993	137,407	282,348	150,900	202,500
Transportation and Related Equipment	69,628	35,827	34,820	38,000	76,000
Communications Equipment	34,023	6,522	40,211	123,900	145,800
Tools and Equipment	2,734	8,798	13,377	14,500	21,200
Sub Total-General Plant Projects	**262,825**	**245,219**	**427,667**	**431,900**	**485,500**
Contributions					
Contributions	(248,034)	(1,020,015)	(642,594)	(505,000)	(571,900)
Sub Total-Contributions	**(248,034)**	**(1,020,015)**	**(642,594)**	**(505,000)**	**(571,900)**
GROSS ASSET TOTAL	**1,027,587**	**2,462,610**	**1,485,248**	**3,442,560**	**6,497,892**

Materiality Analysis on Capital Additions

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:

Capital Additions Materiality

Table 1

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Bridge Year	2009 Test Year
Gross Fixed Assets	$35,058,164	$ 38,960,919	$40,409,084	$43,766,331	$50,177,741
Accumulated Depreciation	$18,087,071	$ 21,759,867	$23,388,379	$25,078,321	$26,972,674
Net Book Value	$16,971,093	$ 17,201,051	$17,020,706	$18,688,011	$23,205,068
Variance calc 1% NBV		$ 172,011	$170,207	$186,880	$232,051

Innisfil Hydro has selected the lowest materiality threshold of $170,000 to allow for the most detailed review of capital additions. Major capital projects from 2005 to 2009 Test Year exceeding the materiality threshold of $170,000 are presented in Exhibit 2, Tab 3, Schedule 2. Costing of each of these capital projects is broken down by key category.

ANALYSIS OF THE CAPITAL EXPENDITURES:

Table 2 –Capital Expenditures by Key Category 2005

2005 Distribution Plant Expenditures

Category	Project Description	Total Project	Customer Demand	Infrastruct	Security	Capacity	Reliability	Regulatory	Substations	Metering
Infrastructure	Pole replacement 10 SR to Hwy 11	166,443		166,443						
Reliability	Guard rails	34,592					34,592			
Infrastructure	Pole replacement 44 kV	36,938		36,938						
Infrastructure	Pole replacement 25th SR	28,387		28,387						
Cust Demand	Emmanual Church u/g primary service	32,402	32,402							
Metering	Miscellaneous customer metering	71,008								71,008
Cust Demand	Miscellaneous customer demand	456,246	456,246							
Infrastructure	Miscellaneous infrastucture	182,274		182,274						
Substation	Substation investments	4,506							4,506	
	Total Distribution Plant Expenditures	**1,012,796**	**488,648**	**414,042**	**-**	**-**	**34,592**	**-**	**4,506**	**71,008**

2005 General Plant Expenditures

Category	Project Description	Total Project	Facilities	Computer Hardware & Software	Transport	Communicate Equipment	Tools
Facilities	Building fixtures & renos	7,923	7,923				
Facilities	Office equip-copier, mailing mach	25,524	25,524				
Computer	Hardware-pc's & printers	20,739		20,739			
Computer	Software-Great Plains & GIS upgrades etc	102,254		102,254			
Transportation	2 Truck	69,628			69,628		
Communicaton	Scada programming & updates	34,022				34,022	
Tools & Equip	Miscellaneous stores equipment	1,360					1,360
Tools & Equip	Miscellaneous tools & shop equipment	948					948
Tools & Equip	Miscellaneous testing equipment	427					427
	Total Distribution Plant Expenditures	**262,825**	**33,447**	**122,993**	**69,628**	**34,022**	**2,735**
	Total Contributions	**(248,034)**					
	Total 2005 Capital Expenditures	**1,027,587**					

The materiality threshold used to analyze the 2005 Capital projects is based on the 1% net asset materiality table of $170k. The 2005 Project exceeding $170k materiality level by key category is:

1. **Customer Demand**: Innisfil Hydro is obligated under the DSC to connect new customer services. These new services or service upgrades may be for new subdivisions, infilling lots, town houses or apartment, commercial and industrial buildings.

Miscellaneous Customer Demand projects – The miscellaneous customer demand projects are the ongoing connections to the distribution system for new or service upgrades for customer services. In 2005 a total of $456k was spent on many various projects relating to this category.

2. **Infrastructure Replacement and Betterments:** These projects involve the replacement of deteriorated or damaged distribution structures and electrical equipment.

Pole replacements - Each year, 1/8th of Innisfil Hydro wood poles are tested and rated to determine when they should be replaced or retested. In 2005, Innisfil Hydro spent $166k replacing 45 poles along highway 89. The project start date was 2005 and the in-service date was 2005. The project scope was to replace substandard pole constructions by today's standards. Phase two of this project was to complete the remainder of the line that spanned from the 10th Side Road of Innisfil on Hwy 89 to County road 11. The poles were in the identical state as the poles replaced the previous year. Approximately 45 poles were replaced, most of which were for the single circuit 44000 Volt sub-transmission line with three phase 8320 Volt underbuild distribution on the poles.

Miscellaneous Infrastructure Replacement and Betterments – The miscellaneous infrastructure projects are the ongoing replacement of deteriorated or damaged distribution structures and electrical equipment. In 2005 $182k was spent on many various projects relating to this category.

Table 3 –2006 Capital Expenditures by Key Category

2006 Distribution Plant Expenditures

Category	Project Description	Total Project	Customer Demand	Infrastruct	Security	Capacity	Reliability	Regulatory	Substations	Metering
Cust Demand	Thor School u/g primary service	29,051	29,051							
Infrastructure	Pole replacement	183,057		183,057						
Infrastructure	Alcona Voltage Conversion	156,695		156,695						
Capacity	Install LeFroy DS F3 feeder	36,406				36,406				
Cust Demand	Royal Distributing u/g primary service	38,954	38,954							
Cust Demand	44 kV line extension	73,540	73,540							
Cust Demand	Capitalized Subdivison Assets Transferred	498,556	498,556							
Substation	New Distribution Station	1,301,539							1,301,539	
Metering	Miscellaneous customer metering	66,265								66,265
Cust Demand	Miscellaneous customer demand	615,902	615,902							
Infrastructure	Miscellaneous infrastucture	237,441		237,441						
	Total Distribution Plant Expenditures	**3,237,406**	**1,256,003**	**577,193**	**-**	**36,406**	**-**	**-**	**1,301,539**	**66,265**

2006 General Plant Expenditures

Category	Project Description	Total Project	Facilities	Computer Hardware & Software	Transport	Communicate Equipment	Tools
Facilities	Paving	33,900	33,900				
Facilities	Building fixtures & renos	16,135	16,135				
Facilities	Office equip-cabinets, furniture	6,629	6,629				
Computer	Hardware-servers, pc's & printers	65,316		65,316			
Computer	Software-Bar coding, Filenexus upgrades e	72,091		72,091			
Transportation	1 Truck	35,827			35,827		
Communicaton	Scada programming & updates	6,522				6,522	
Tools & Equip	Miscellaneous stores equipment	672					672
Tools & Equip	Miscellaneous tools & shop equipment	8,127					8,127
Tools & Equip	Miscellaneous testing equipment	0					
	Total Distribution Plant Expenditures	**245,219**	**56,664**	**137,407**	**35,827**	**6,522**	**8,799**
	Total Contributions	**(1,020,015)**					
	Total 2006 Capital Expenditures	**2,462,610**					

The materiality threshold used to analyze the 2006 Capital projects is based on the 1% net asset materiality table of $170k. The 2006 Projects exceeding $170k materiality level by key category are:

1. **Customer Demand**: Innisfil Hydro is obligated under the DSC to connect new customer services. These new services or service upgrades may be for new subdivisions, infilling lots, town houses or apartment, commercial and industrial buildings.

   Economic Evaluation - Innisfil Hydro assumed the Previn Court subdivision with an asset cost of $498k. Through the economic evaluation process, $179k was paid to the developer present valuing the net of the revenue and maintenance expenses. The $319k was the balance of the asset cost value Innisfil Hydro is assuming which is offset to contributions. The net asset impact is $179k. The project starting date was 2004 and in-service date was 2006.

Miscellaneous Customer Demand projects – The miscellaneous customer demand projects are the ongoing connections to the distribution system for new or service upgrades for customer services. In 2006 a total of $616k was spent on many various projects relating to this category.

2. **Infrastructure Replacement and Betterments:** These projects involve the replacement of deteriorated or damaged distribution structures and electrical equipment.

Pole replacements - Each year, 1/8th of Innisfil Hydro wood poles are tested and rated to determine when they should be replaced or retested. In 2006, Innisfil Hydro spent $183k replacing 65 poles. The project start date was 2006 and the in-service date was 2006. The project scope was to replace substandard pole constructions by today's standards. The majority of the poles replaced were for the double circuit 44000 Volt sub-transmission with a three phase 8320 Volt under-build distribution on the poles.

Voltage conversion - A business case study was completed by Innisfil Hydro staff and it was determined that converting the town of Alcona from its 8320 Volt system to a 27600 Volt system would save the company losses based on the operating efficiency of the higher Voltage. Phase 1 of this project was the Voltage conversion costing $157k. With a pending road widening eminent to occur in the near future in front of the 44000 to 8320 Volt substation running the 8320 Volt system, there would not be a safe distance to the front of the station being it resided close to the existing road allowance.

Miscellaneous Infrastructure Replacement and Betterments – The miscellaneous infrastructure projects are the ongoing replacement of deteriorated or damaged distribution structures and electrical equipment. In 2006 $237k was spent on many various projects relating to this category.

3. **Substations:** Substation investments are undertaken to improve or maintain reliability to large numbers of customers and to maintain security and safety at the substations.

Bob Deugo Distribution Station - The scope and focus of this project was to construct a 44000 Volt to 27600 Volt distribution station to back up an islanded 44000 Volt to 27600 station called the Brian Wilson Distribution Station in Alcona at a cost of $1,301k. The Brian Wilson station was the first station in Innisfil that operated at the more efficient 27600 Volt system. The only foreseeable drawback to this was that a back up redundancy was not in place or available. The Bob Deugo station would provide security for the Brian Wilson station should a catastrophic fault occur in that station, now decreasing outage duration and decreasing restoration times. The new station also provided future capacity growth for the Highway 400 industrial corridor, which in the near future will start to expand. The project start date was 2006 and the in-service date was 2006. A capital contribution of $278k is also recognized for this project. This amount was transferred form a Development Charges Fund account which included monies received for development charges post 1999.

Table 4 –2007 Capital Expenditures by Key Category

2007 Distribution Plant Expenditures

Category	Project Description	Total Project	Customer Demand	Infrastruct	Security	Capacity	Reliability	Regulatory	Substations	Metering
Capacity	9M3 &9M6 double circuit 44 kV extension	35,179				35,179				
Cust Demand	Pole relocate for entrance into subdivision	50,011	50,011							
Reliability	Extend 44000 volt subtransmission	210,551					210,551			
Cust Demand	Private primary service	19,639	19,639							
Cust Demand	Town booster station for water supply	36,905	36,905							
Infrastructure	Alcona voltage conversion	315,260		315,260						
Cust Demand	Road relocate 9 double circuit	131,068	131,068							
Cust Demand	Town Admin building u/g primary service	39,834	39,834							
Cust Demand	Subaru car dealership u/g primary service	38,099	38,099							
Cust Demand	Mercedez car dealership u/g primary serv	36,023	36,023							
Cust Demand	Shell and Tim's u/g primary service	30,250	30,250							
Cust Demand	Woodland Park subdivision	27,152	27,152							
Metering	Miscellaneous customer metering	43,048								43,048
Cust Demand	Miscellaneous customer demand	444,473	444,473							
Infrastructure	Miscellaneous infrastucture	214,307		214,307						
Substation	Substation investments	28,376							28,376	
	Total Distribution Plant Expenditures	**1,700,175**	**853,454**	**529,567**	**-**	**35,179**	**210,551**	**-**	**28,376**	**43,048**

2007 General Plant Expenditures

Category	Project Description	Total Project	Facilities	Computer Hardware & Software	Transport	Communicate Equipment	Tools
Facilities	Miscellaneous building fixtures	28,536	28,536				
Facilities	Windows-Customer Service building	14,500	14,500				
Facilities	Office equip-cabinets, furniture	13,875	13,875				
Computer	Hardware-servers, pc's & printers	108,353		108,353			
Computer	Software-Harris, payroll, upgrades etc	173,995		173,995			
Transportation	1 Truck	34,820			34,820		
Communicaton	BD distribution station	5,294				5,294	
Communicaton	Scada wide screen	4,198				4,198	
Communicaton	Scada programming & updates	30,719				30,719	
Tools & Equip	Miscellaneous stores equipment	561					561
Tools & Equip	Miscellaneous tools & shop equipment	6,541					6,541
Tools & Equip	Miscellaneous testing equipment	6,275					6,275
	Total Distribution Plant Expenditures	**427,667**	**56,911**	**282,348**	**34,820**	**40,211**	**13,377**
	Total Contributions	**(642,594)**					
	Total 2007 Capital Expenditures	**1,485,248**					

The materiality threshold used to analyze the 2007 Capital projects is based on the 1% net asset materiality table of $170k. The 2007 Projects exceeding $170k materiality level by key category are:

1. **Customer Demand**: Innisfil Hydro is obligated under the DSC to connect new customer services. These new services or service upgrades may be for new subdivisions, infilling lots, town houses or apartment, commercial and industrial buildings.

Road relocate – The Town of Innisfil initiated a road relocate for the new recreation centre. Approximately 9 double circuit 44 kV sub and service poles were relocated. Innisfil Hydro was responsible for 50% of the internal and external labour and equipment costs and 100% of the material costs. The net cost to Innisfil Hydro was $130k. The project starting date was 2007 and in-service date was 2007.

Miscellaneous Customer Demand projects – The miscellaneous customer demand projects are the ongoing connections to the distribution system for new or service upgrades for customer services. In 2007 a total of $444k was spent on many various projects relating to this category.

2. **Infrastructure Replacement and Betterments:** These projects involve the replacement of deteriorated or damaged distribution structures and electrical equipment.

Voltage conversion - A business case study was completed by Innisfil Hydro staff and it was determined that converting the town of Alcona from its 8320 Volt system to a 27600 Volt system would save the company losses based on the operating efficiency of the higher Voltage. Phase 2 of this project was to complete the Voltage conversion of 8320 Volt to 27600 Volt in Alcona, decommission and remove from service the existing 8320 Volt power transformer costing $315k. The project starting date was 2007 and in-service date was 2007.

Miscellaneous Infrastructure Replacement and Betterments – The miscellaneous infrastructure projects are the ongoing replacement of deteriorated or damaged distribution structures and electrical equipment. In 2007 $214k was spent on many various projects relating to this category.

3. **Reliability and System Automation:** The main driver for these investments is an analysis of what measures could be undertaken to improve Innisfil Hydro

reliability performance as measured by SAIDI, SAIFI and CAIDI indices. These indices are indicators of the reliability of Innisfil Hydro distribution system. These activities will support maintenance of or improvement to the Service Quality Indices measured and submitted to the OEB each year by each Utility.

Extend 44000 Volt sub-transmission - The scope and focus of this job was to extend the current 44000 Volt sub-transmission to create an internal tie point within Innisfil Hydro system for redundancy purposes and future accommodation of two new 44000 Volt feeders that are to enter Innisfil Hydro territory at a costs of $210k. No tie point at this location was present to be able to back up one of two feeders in that location. With the onset of this job, SCADA (remote) controlled switches were installed to maximize restoration times and lower SAIDI and CAIDI reportable times. Approximately 10 poles were required for this job. The project starting date was 2007 and in-service date was 2007.

Table 5 –2008 Capital Expenditures by Key Category

2008 Distribution Plant Expenditures

Category	Project Description	Total Project	Customer Demand	Infrastruct	Security	Capacity	Reliability	Regulatory	Substations	Metering
Regulatory	Line Ext 15th line	81,900						81,900		
Security	44 kV line ext BBP	360,400			360,400					
Regulatory	Line rebuild Hwy 27	125,800						125,800		
Reliability	Guard rails	170,000					170,000			
Cust Demand	Road widening	750,000	750,000							
Reliability	44 kV mechanized Altdi-Ruptor Scada	192,950					192,950			
Reliability	27.6 kV mechanized Scada-mate switch	132,750					132,750			
Infrastructure	Pole replacement	236,510		236,510						
Metering	Industrial Park Road TX	27,000								27,000
Metering	Miscellaneous customer metering	53,000								53,000
Cust Demand	Miscellaneous customer demand	950,055	950,055							
Infrastructure	Miscellaneous infrastucture	376,445		376,445						
Substation	Substation investments	58,850							58,850	
	Total Distribution Plant Expenditures	**3,515,660**	**1,700,055**	**612,955**	**360,400**	**-**	**495,700**	**207,700**	**58,850**	**80,000**

2008 General Plant Expenditures

Category	Project Description	Total Project	Facilities	Computer Hardware & Software	Transport	Communicate Equipment	Tools
Facilities	Misc building fixtures and fencing	25,000	25,000				
Facilities	2 Portables	60,000	60,000				
Facilities	Office furniture	19,600	19,600				
Computer	Hardware-servers, pc's & printers	60,500		60,500			
Computer	Software-HR module, upgrades etc	90,400		90,400			
Transportation	1 Trucks	38,000			38,000		
Communicaton	44 kV line ext on BBP	19,600				19,600	
Communicaton	44 kV mechanized Altdi-Ruptor Scada	51,000				51,000	
Communicaton	27.6 kV mechanized Scada mate switch	9,300				9,300	
Communicaton	27.6 kV radio repeated fault indicator	27,000				27,000	
Communicaton	Scada programming & updates	17,000				17,000	
Tools & Equip	Miscellaneous stores equipment	3,500					3,500
Tools & Equip	Miscellaneous tools & shop equipment	9,000					9,000
Tools & Equip	Miscellaneous testing equipment	2,000					2,000
	Total Distribution Plant Expenditures	**431,900**	**104,600**	**150,900**	**38,000**	**123,900**	**14,500**
	Total Contributions	**(505,000)**					
	Total 2008 Capital Expenditures	**3,442,560**					

The materiality threshold used to analyze the 2008 Capital projects is based on the 1% net asset materiality table of $170k. The 2008 Projects exceeding $170k materiality level by key category are:

1. **Customer Demand**: Innisfil Hydro is obligated under the DSC to connect new customer services. These new services or service upgrades may be for new

subdivisions, infilling lots, town houses or apartment, commercial and industrial buildings.

Road relocate – The Town of Innisfil initiated overhead to underground relocate and urbanization of Innisfil Beach Road section one. Preliminary engineering and design plans in combination with overhead lines that will need to be relocated and buried between the 25th Side Road and St. John's Padmounted Switchgears and transformers will be installed with buried primary and secondary cables for two feeders out of the Brian Wilson station. This will accommodate the Town of Innisfil's road widening and urbanization plans. This project is staged over four years from 2008 to 2011. Innisfil Hydro was responsible for 50% of the internal and external labour and equipment costs and 100% of the material costs. It is estimated this will cost $750k. The first phase of the project starting date and in-service date is 2008.

Miscellaneous Customer Demand projects – The miscellaneous customer demand projects have increased from 2007 of $444k to 2008 of $950k. The cost drivers driving this increase are increases to raw materials such as copper, aluminum and steel that make up a vast majority of hydro materials, an increase in build to standards efficiency to fully meet compliance under O. REG 22/04 from the Electrical Safety Authority, seasonal timing of the project planning of the capital budget and an instrumental change of line crew contractor. The line crew contractor services that had been utilized has been sold effective June 2008. Innisfil Hydro requested RFQ by April 2008 which resulted in new market pricing to base estimates for 2008 and 2009 project costs on. Innisfil Hydro has no internal line crew so this staffing is 100% relied on external sources.

2. **Infrastructure Replacement and Betterments:** These projects involve the replacement of deteriorated or damaged distribution structures and electrical equipment.

Pole Replacement - Each year, 1/8th of Innisfil Hydro wood poles are tested and rated to determine when they should be replaced or retested. This test includes resistograph boring into the base of the pole to detect internal decay and dry rot. A visual inspection of the pole with notes and recommendations is also included with this test. It is estimated there will be a 4% failure rate which will result with the replacement of 60 poles including any hardware required for these replacements. The cost is estimated at $237k. The project start date and the in-service date is estimated to be 2008.

Miscellaneous Infrastructure Replacement and Betterments – The miscellaneous customer demand projects have increased from 2007 of $214k to 2008 of $376k. The cost drivers driving this increase are increases to raw materials such as copper, aluminum and steel that make up a vast majority of hydro materials, an increase in build to standards efficiency to fully meet compliance under O. REG 22/04 from the Electrical Safety Authority, seasonal timing of the project planning of the capital budget and an instrumental change of line crew contractor. The line crew contractor services that had been utilized has been sold effective June 2008. Innisfil Hydro requested RFQ by April 2008 which resulted in new market pricing to base estimates for 2008 and 2009 project costs on. Innisfil Hydro has no internal line crew so this staffing is 100% relied on external sources.

3. **Security:** There are some areas of the distribution system where failure of equipment may cause large outages, which cannot be restored through switching to alternate supplies. The probability and impact of asset failure are considered at peak load to determine the risk the failure creates. In these cases, projects are developed to add switching devices or create a backup feeder supply to reduce the risk to typical restoration times for Innisfil Hydro and its surround utilities.

44 kV Line Extension – This project is a line extension of the 44000 Volt sub-transmission scheduled in two phases. The Barrie 13M3 feeder is currently a radial feed from Lockhart Road north on the 25th Side Road of Innisfil. This radial section has one (1) distribution station (Big Bay Point DS) with approximately 1600 hydro accounts off it and 1-44000 Volt private station (Kempenfelt Center). Upon the completion of this project, redundancy for both the Kempenfelt Center and the Big Bay Point D.S will be available. The line extension will loop these stations together for better reliability, should problems occur in the 44kV circuit north of Lockhart Road. This will dramatically reduce restoration times in the event of an emergency. The 2008 phase of the capital project will consist of framing and installing approximately eight one (81) poles within a four (4) KM stretch of the 20th Side Road north to Big Bay Point Road then east to the 44000 Volt fairway Road tap, including the transfer of the existing three (3) phase line for approximately 2.4 KM to new poles and completing half of the guying and anchoring locations. This project is a two phase project and the first phase is estimated to costs $360k. Phase one's starting date is 2008 and in-service date is 2008.

4. **Reliability and System Automation:** The main driver for these investments is an analysis of what measures could be undertaken to improve Innisfil Hydro reliability performance as measured by SAIDI, SAIFI and CAIDI indices. These indices are indicators of the reliability of Innisfil Hydro distribution system. These activities will support maintenance of or improvement to the Service Quality Indices measured and submitted to the OEB each year by Innisfil Hydro.

Guard Rail Installments - The purpose of this capital expenditure is to protect Innisfil Hydro's investments of motorized SCADA equipment with five (5) guard rails at the base of hydro poles where the 44000 Volt switches reside. As Innisfil Hydro progresses with automation of it SCADA system, the cost of replacement and damage caused by vehicular accidents can be mitigated by the installation of guard rails. Anywhere from 6 to 10 poles a year are damaged or broke by vehicular accidents in Innisfil, creating power outages and replacements to fix these problems. With the capital investment costs of the motors and electronics at the base of the pole the possibility of a prolonged outage due to the fact it is an isolating device that has been damaged, guard rails in higher vehicular traffic is necessary for protection. Innisfil hydro has approximately 22 SCADA controlled motorized switches in it distribution area with only three (3) currently protected by guard rails. The scope and focus of this expenditure is to protect the pole with the switch apparatus mounted on it and also to reduce the SAIDI, SAIFI and CAIDI reporting should one of these poles be targeted.. The estimated cost of this project is $170k. The project starting date is 2008 and in-service date is 2008.

Install Four 44kV mechanized Altdi-Ruptor Scada Switches – The purpose of this capital expenditure is to install four (4) SCADA controlled load interrupting 44000 Volt switches into its sub-transmission system. Three (3) of these switches shall replace an aging and obsolete airbreak switch. Innisfil Hydro has approximately 34 air break style, gang operated switches in its system, all of which will not break load in the 44,000 Volt system. The three replacements will be the boarder entry point locations were Hydro One meets Innisfil Hydro. It is essential to have a 44000 Volt switch that can break load at these locations for emergency switching and/or pick up or drop out in brownout or blackout conditions. The fourth motorized switch location will be a new installation into the sub-transmission that runs parallel along highway 400. The prompt for this new switch was the related weather issues of salt and other debris from the highway. In Feb of 2007 a 44000 Volt conductor burned to the ground knocking out power to 4200 hydro accounts until alternate switching could be done. Salt contaminants were found to be part of the root cause of the problem. This new switch will give the flexibility to isolate faults of that nature immediately. All the new switches will be able to break load and be designed using SCADA remote switching technology to faster isolate faulted locations in the 44000 Volt sub-transmission system greatly reducing SAIDI, SAIFI and CAIDI figures. The estimated cost is $193k. The project starting date is 2008 and in-service date is 2008.

Install 27.6 kV mechanized Scada-Mate Switches – The scope and focus of this project is to install 4 switches. The installation of the 27.6 kV switches is to provide redundancy back up feeds for the Yonge Street/Innisfil Beach Road area and the Industrial Park areas. The estimated cost is $133k. The project starting date is 2008 and in-service date is 2008.

5. **Regulatory Requirements:** These projects are system capital investments which are being driven by regulatory requirements. These may include, among others, directions from the OEB, the IESO, the Ministry of Energy or the Ministry of Environment.

Line Rebuild on Highway 27 - The scope and focus of this project is to construct the line to eliminate the load transfer issues south of Cookstown on County Road 27. Presently Hydro One services Innisfil Hydro customers' two spans south of Kidds Lane to the Innisfil Hydro boarder. The estimated cost is $126k. The project starting and in-service date is estimated 2008.

Table 6 –2009 Capital Expenditures by Key Category

2009 Distribution Plant Expenditures

Category	Project Description	Total Project	Customer Demand	Infrastruct	Security	Capacity	Reliability	Regulatory	Substations	Metering
Infrastructure	Pole Replacement	271,500		271,500						
Reliability	44 kV Load Interrupters	290,540					290,540			
Infrastructure	Industrial Park Rd Transformer replac	52,200		52,200						
Security	9M4 ext-20 SR 10th line	198,900			198,900					
Reliability	Reclosurer automation	133,900					133,900			
Cust Demand	Utility relocates	266,900	266,900							
Reliability	27.6 SCADA mates	149,600					149,600			
Capacity	44 kV line ext 20th SR	389,300				389,300				
Metering	Wholesale meters	140,000								140,000
Reliability	Guard rails	132,900					132,900			
Cust Demand	Road widening	788,800	788,800							
Infrastructure	27 kV voltage conver 20 SR 5th & 6th	184,100		184,100						
Capacity	27 kV voltage extension 20 SR 7th & 4th	714,550				714,550				
Infrastructure	Betterment	184,700		184,700						
Reliability	Hydro One build double circuit	500,000					500,000			
Reliability	9M3 9M6 extension	853,186					853,186			
Cust Demand	Miscellaneous customer demand	985,860	985,860							
Infrastructure	Miscellaneous infrastucture	341,156		341,156						
Substation	Substation investments	2,200							2,200	
Metering	Miscellaneous customer metering	4,000								4,000
	Total Distribution Plant Expenditures	**6,584,292**	**2,041,560**	**1,033,656**	**198,900**	**1,103,850**	**2,060,126**	**-**	**2,200**	**144,000**

2009 General Plant Expenditures

Category	Project Description	Total Project	Facilities	Computer Hardware & Software	Transport	Communicate Equipment	Tools
Facilities	Miscellaneous building fixtures	25,000	25,000				
Facilities	Office equip-copier, scanner etc	15,000	15,000				
Computer	Hardware-servers, pc's & printers	95,000		95,000			
Computer	Software-autocad, upgrades etc	107,500		107,500			
Transportation	2 Trucks	76,000			76,000		
Communicaton	27.6 kV radio fault indicators	38,800				38,800	
Communicaton	44 kV load interruptors	33,900				33,900	
Communicaton	Recloser automation & replacement	2,500				2,500	
Communicaton	Utility relocates	2,500				2,500	
Communicaton	27.6kV SCADA mates	10,200				10,200	
Communicaton	44 kV line ext	17,200				17,200	
Communicaton	New fault indicating & switch devices	18,700				18,700	
Communicaton	Scada programming & updates	22,000				22,000	
Tools & Equip	Miscellaneous stores equipment	3,700					3,700
Tools & Equip	Miscellaneous tools & shop equipment	9,500					9,500
Tools & Equip	Miscellaneous testing equipment	8,000					8,000
	Total Distribution Plant Expenditures	**485,500**	**40,000**	**202,500**	**76,000**	**145,800**	**21,200**
	Total Contributions	**(571,900)**					
	Total 2009 Capital Expenditures	**6,497,892**					

The materiality threshold used to analyze the 2009 Capital projects is based on the 1% net asset materiality table of $170k. The 2009 Projects exceeding $170k materiality level by key category are:

1. **Customer Demand**: Innisfil Hydro is obligated under the DSC to connect new customer services. These new services or service upgrades may be for new subdivisions, infilling lots, town houses or apartment, commercial and industrial buildings.

Road relocate – The Town of Innisfil initiated overhead to underground relocate and urbanization of Innisfil Beach Road phase two. Preliminary engineering and design plans in combination with overhead lines that will need to be relocated and buried between St. John's Road and Jans Blvd in Innisfil. It is a section of road approximately one (1) KM long. The scope of this project would include such things as the removal of all overhead conductors and devices, installation of padmounted switchgears and transformers along with buried primary and secondary cables for two (2) feeders out of the Brian Wilson Station. Consideration has also been given to motorize some of the new buried infrastructure so that outage times can be reduced utilizing the Innisfil Hydro SCADA system at the same time as increasing reliability to its customers. This project is staged over four years from 2008 to 2011. Innisfil Hydro is responsible for 50% of the internal and external labour and equipment costs and 100% of the material costs. It is estimated the second phase will cost $789k. The second phase of the project starting date and in-service date is 2009.

Utility Relocates – The County of Simcoe has indicated construction in five designated areas of Innisfil. These projects range from road widening to traffic signal installations. The county draft proposals indicate the work is to be complete in 2009. Two (2) of the five (5) draft plans received to date have been reviewed, of which the one located at Innisfil Beach Road and 20th Side Road has a large scope of work, including relocating approximately 8 spans (seven poles) of double circuited 44,000 Volt sub-transmission with two (2) locations having 44,000 Volt mechanized SCADA load interrupter switches on them. Also within that scope, four (4) poles for guying and servicing are included and all related activity such as transferring of primary and/or secondary underground and overhead wires, transformer relocation if required, anchor installations and lead replacement. The second plan reviewed consisted of relocating eight (8) poles on the Seventh line and 20th Side Road of Innisfil intersection. Approximately three (3) of these poles have the 44000 Volt sub-transmission on them while the remainder have single and three phase circuits on them. All work such as transferring of primary and/or secondary underground and overhead wires, transformer relocation if required, anchor installations and lead replacement are included and it is estimated to cost $267k. The starting and in-service date is 2009. The remaining three plans, although confirmed by the County, have not yet been issued or included in the 2009 Test Year projects.

Miscellaneous Customer Demand projects – The miscellaneous customer demand projects have increased from 2008 of $950k to 2009 of $986k. This is mainly due to the change of line crew contractor. The line crew contractor services that had been utilized has been sold effective June 2008. Innisfil Hydro requested RFQ by April 2008 which resulted in new market pricing to base estimates for 2008 and 2009 project costs on. Innisfil Hydro has no internal line crew so this staffing is 100% relied on external sources.

2. **Infrastructure Replacement and Betterments:** These projects involve the replacement of deteriorated or damaged distribution structures and electrical equipment.

Pole Replacement - Each year, 1/8th of Innisfil Hydro wood poles are tested and rated to determine when they should be replaced or retested. This test includes resistograph boring into the base of the pole to detect internal decay and dry rot. A visual inspection of the pole with notes and recommendations is also included with this test. It is estimated there will be a 4% failure rate which will result with the replacement of 60 poles including any activity such as transferring of primary and /or secondary underground and overhead wires, transformer relocation if required, anchor installations and lead replacement. The cost is estimated at $272k. The project start date and the in-service date is estimated to be 2009.

27kV Voltage Conversion – This project is a second phase of Innisfil Hydro's Infrastructure Betterments listed below. Upon completion of the Infrastructure Betterment, Innisfil Hydro intends on utilizing the new, more efficient 27600/16000 Volt system now in the vicinity of the 6th and 5th lines of Innisfil. At the present time, the two concessions are feed from an 8320/4800 Volt system from Lefroy. The intention of this project is to lower the line losses from converting to the higher Voltage and increase reliability to the customers on those concession roads. The project entails reframing poles where adequate height exists and replacing approximately thirty (30) poles that are not high enough to meet present day ESA standards. When this project is complete, Innisfil Hydro will have converted approximately 3.5 KM of distribution line. The cost is estimated at $184k. The project start date and the in-service date is estimated to be 2009.

Infrastructure Betterments – This capital expenditure justifies the ongoing need to maintain the reliability of the distribution system for whatever such reason resembling defects, wear or safety issues to the distributor's assets. The main concern here is not only outage reporting but also public and staff safety. The scope of this project is actually broke out into several categories of betterment replacements. The first is the replacement of 100 porcelain 27600/16000 Volt and 8320/4800 Volt distribution class cutout switches. Over the past several years, these switches have begun to fail prompting replacement programs where hundreds of suspect, cracked and defective switches have been replaced. Not always visible from the ground, it can happen when the switch is being operated causing an even greater problem and danger for utility staff. Approximately 30 spans of secondary buss replacement have been budgeted to replace. The old buss works that is known starting to lose its insulation from UV and other weather related factors is becoming a danger to working utility staff. The old secondary buss is removed from service and the new larger, to today standards buss is installed, thus handling higher capacities and lower line loses. Approximately 24 porcelain dead end bell style 44000 Volt insulators are scheduled for replacement. These dead end insulators are noted to have cracking issues in the porcelain due to weather elements or manufactures' defect (cement growth). Approximately 4000 customers (approximatly10000 residents) lost power when a failure of one of these units in 2005 happened on a Hydro one piece of line that was shared by Innisfil Hydro. Of recent in June of 2008, another of these units failed during a storm causing an approximate 8500 customers (22000 customers) to lose power in Innisfil. Innisfil Hydro's intention is to start replacing these porcelain dead end insulators with polymeric dead end insulators. The last portion of this project is to start by replacing 50 porcelain dead end insulators in the 27600/16000 Volt 8320/4800. These porcelain dead end insulators have the same issues as the 44000 Volt dead ends however, they tend to cause more damage than outage compared to the 44000 Volt problem. The typical process when a lower voltage dead end fails is to burn through the pole before causing an outage becoming an even bigger danger to staff and/or the public. Often a pole replacement is needed in the aftermath of this situation. The cost is estimated at $185k. The project start date and the in-service date is estimated to be 2009.

Miscellaneous Infrastructure Replacement and Betterments – The miscellaneous customer demand projects have decreased from 2008 of $376k to 2009 of $341k due to resources being utilized on the above noted projects.

3. **Security:** There are some areas of the distribution system where failure of equipment may cause large outages, which cannot be restored through switching to alternate supplies. The probability and impact of asset failure are considered at

peak load to determine the risk the failure creates. In these cases, projects are developed to add switching devices or create a backup feeder supply to reduce the risk to typical restoration times for Innisfil Hydro and its surround utilities.

9M4 Extension – This 44kV line extension is designed to allow the backup of the recently completed 13M3 extension on the 20th Side Road north of Lockhart Road (project number IHDSL 2009 DO008). No internal tie point within Innisfil Hydro's system is present there. This project will consist of replacing an existing pole line for one and one half (11/2) KM and will assist switching within the 44000 Volt sub-transmission to supply and sectionalize at a much faster rate and back up the 13M3 feeder out of Barrie with the 9M4 out of Alliston. Therefore, this capital expenditure of 9M4-13M3 44kV feeder tie will significantly reduce the SAIDI/SAIFI/CAIDI reporting in outage conditions, create new alternatives for scheduled switching, and work protection. Besides having the capability to back up the Barrie 13M3 at this location it will also have the potential in the future for dividing loads, pending the two (2) new incoming feeders from Alliston (project number IHDSL 2009 DO017). The cost is estimated at $199k. The project start date and the in-service date is estimated to be 2009.

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

44 kV Line Extension – This project is phase 2 of the Barrie M3 line extension (CDP2008-2) from 2008. The completion of this project will provide redundancy for both the Kempenfelt Center and the Big Bay Point DS 44,000 Volt stations that are presently radial fed from Lockhart Road north. This line upon completion will loop these stations together for better reliability, should problems occur in the

44kV north of Lockhart Road. This will dramatically reduce restoration times in the event of an emergency. The 2009 portion of this capital project will consist of framing and installing approximately four (4) KM of 556.6 MCM 44000 Volt sub-transmission three (3) phase line, transferring approximately 1.6 KM of three phase distribution to new poles, completing guying and anchoring locations, installation of two (2) SCADA controlled 44 KV load interrupting switches for fast isolation and significantly reduce the SAIDI/SAIFI/CAIDI reporting in outage conditions as well as create new alternatives for scheduled switching, and work protection. This project is a two phase project and the second phase is estimated to costs $389k. The 2009 planning consist of stringing conductors and switching components to complete the phase. Phase two's starting date is 2009 and in-service date is 2009.

27/6 kV Line Extension – A line extension of the 27600 Volt system out of the Brian Wilson Station in Alcona will need to be constructed for the LSAMI development, which is a subdivision with an approximate 1200 new Hydro customer accounts and possible 1450 accounts if an extension is approved in Lefroy. This project is predicted to start deep servicing toward the end of 2009. Currently Lefroy is feed off a 44000 Volt to 8320 Volt substation that is near capacity and will not be able to supply the needs of electricity for the entire development. The line extension will replace an approximate 4.8 KM of existing pole line that currently only has the 44000 Volt sub-transmission on them. The scope of this project has several key ambitions one of which is not only to extend the 27600 Volt system to Lefroy for the LSAMI project but the new 27600 Volt line will serve as a back up to the Brian Wilson Station when in 2010, a new substation, 44000 Volt to 27600 Volt will be constructed in Lefroy as identified in Innisfil Hydro's five year business plan. When the new 27600 Volt station is in service it will be the backup between the two stations and avoid islanding the new station. What will also make this project more feasible is the replacement of aged poles that over the past several years have been spot replaced due to rot or infestation and are approximately the same vintage in the 4.8 KM stretch. Lastly, the completion of this project will set in motion project number IHDSL 2009 DO013, which is to covert portions of the fifth and sixth lines of Innisfil to the more efficient 27600 Voltage. This project is estimated to costs $715k. The estimated starting date is 2009 and in-service date is 2009.

5. **Reliability and System Automation:** The main driver for these investments is an analysis of what measures could be undertaken to improve Innisfil Hydro's reliability performance as measured by SAIDI, SAIFI and CAIDI indices. These indices are indicators of the reliability of Innisfil Hydro's distribution system. These activities will support maintenance of or improvement to the Service Quality Indices measured and submitted to the OEB each year by Innisfil Hydro.

Install Four Load Interruptors – The purpose of this capital expenditure is to install four (4) SCADA controlled load interrupting 44000 Volt switches into its sub-transmission system. Each of these switches shall replace an aging and obsolete airbreak or midspan opener location. Innisfil Hydro has approximately 34 air break style, gang operated switches and approximately thirty (30) Mid-span Opener (MSO) locations in its system, all of which neither the airbreak nor midspan opener installations are not equipped to break load in the 44,000 Volt system. The new switches will be able to break load and be designed using SCADA remote switching technology to faster isolate faulted locations in the 44000 Volt sub-transmission system greatly reducing SAIDI, SAIFI and CAIDI reporting. The estimated cost is $291k. The project starting date is 2009 and in-service date is 2009.

Hydro One Built Double Circuit 44kV – The scope and focus of this project is Hydro One is building double circuit 9M3/9M6 feeders for Innisfil Hydro's supply. These two feeders will provide future load growth as well as back up for the other 44kV feeders in Innisfil. The estimated contribution required by Hydro One is $500k. The project starting date is 2009 and in-service date is 2009.

9M3 9M6 Extension – A line extension of double circuit 44000 Volt sub-transmission is the scope and focus of this project. Two available feeder positions have come available from Hydro One out of the Alliston Transformer Station, and with the anticipated load growth for Innisfil Hydro it was determined that the two (2) feeders would be utilized by Innisfil Hydro, not only for growth but for back up to the other three (3) sub-transmission feeders into Innisfil. An approximate four (4) KM of double circuit 44,000 Volt sub-transmission will be built from the 10 Side Road of Essa south on Highway 27 and across the 5th Line of Innisfil to the 5 Side Road. The two (2) new incoming feeders should provide enough capacity for Innisfil until 2022, at which point a Transformer Station of 27600 Volts will need to be constructed for further anticipated growth. Approximately sixty-five (65) poles will replace existing smaller single phase and three phase poles in order to accommodate for the sub-transmission circuits. Within the scope of this project three (3) 44000 Volt SCADA load break switches are to be installed; two (2) at the Innisfil Hydro/Hydro One border and a third as a paralleling point within Innisfil Hydro's system. The estimated cost of this project is $853k. The project starting date is 2009 and in-service date is 2009.

CAPITAL CONTRIBUTIONS:

The following table sets out historical capital contributions for 2006 and 2007 Actual, the 2008 Bridge Year and the 2009 Test Year.

Capital Contributions 2004-2009 ($000's)

Table 1

	2006 EDR (04Act)	2005 Actual	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Total	(359)	(248)	(1,020)	(643)	(505)	(572)

Capital Contribution Methodology:

- **Industrial or Commercial Customer Substation Projects:**

These projects are installations in which Innisfil Hydro will install equipment to connect a new commercial or industrial customer.

As noted above, Innisfil Hydro performs an economic evaluation (prepared in accordance with the OEB's prescribed valuation methodologies) of service projects that require new facilities to be built on the distribution system or those that require an increase in capacity of the distribution system.

- **Subdivision Development:**

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 DSC and described above are applied to residential expansions. The capital budget amounts reflect those expansion costs that are not recovered through capital contributions. The work predicted for this category for 2009 is derived from a combination of historical spending and anticipated projects.

- **Roadway Reconstruction:**

The primary drivers for these projects are requests by municipalities and road authorities for plant relocation and/or modifications. These projects generally occur due to road widening, resurfacing, and or realignment. The *Public Service Works on Highways Act* provides for a cost sharing arrangement whereby the road authority contributes 50% of the cost of labour and equipment for the project. Innisfil Hydro is responsible for the remaining 50% of the labour and equipment cost, and 100% of the cost of material for the project.

Projects that fall into this category are requested by customers and/or municipalities and road authorities throughout the year. The work predicted for this category for 2009 is derived from advance notice on Town projects as well as anticipated projects. Innisfil Hydro currently has 2 roadway reconstruction projects planned for the 2009 Test Year.

CAPITALIZATION POLICY:

Innisfil Hydro 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. Innisfil Hydro does not currently capitalize interest on funds for 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.

WORKING CAPITAL CALCULATION

OVERVIEW:

Innisfil Hydro's working capital allowance is forecast to be $3,142,827 for 2009 and is based on the "15% of specific O&M accounts formula approach" referred to at page 15 of the Board's Filing Requirements. Innisfil Hydro has provided its calculations by account for each of 2006 Actual, 2007 Actual, the 2008 Bridge Year and the 2009 Test Year in Table 1 on the following page.

Working Capital Calculation by Account

Table 1

Description	2006 Actual	Allowance for Working Capital	2007 Actual	Allowance for Working Capital	2008 Bridge	Allowance for Working Capital	2009 Test	Allowance for Working Capital
Rate used for Working Capital Allowance		15%		15%		15%		15%
Operation								
5005-Operation Supervision and Engineering	54,587	8,188	56,710	8,507	70,525	10,579	72,325	10,849
5010-Load Dispatching	3,985	598	5,531	830	5,800	870	6,050	908
5012-Station Buildings and Fixtures Expense	38,576	5,786	37,632	5,645	38,450	5,768	40,400	6,060
5014-Transformer Station Equipment - Operation Labour	0	0	0	0	0	0	0	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0	0	0	0	0	0	0	0
5016-Distribution Station Equipment - Operation Labour	5,111	767	6,712	1,007	7,100	1,065	7,400	1,110
5017-Distribution Station Equipment - Operation Supplies and Expenses	1,360	204	1,703	256	1,850	278	2,000	300
5020-Overhead Distribution Lines and Feeders - Operation Labour	11,733	1,760	28,806	4,321	36,850	5,528	40,850	6,128
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	27,713	4,157	31,471	4,721	32,400	4,860	36,600	5,490
5030-Overhead Sub transmission Feeders - Operation	2,158	324	2,610	392	2,950	443	3,250	488
5035-Overhead Distribution Transformers- Operation	2,244	337	2,097	315	3,350	503	3,650	548
5040-Underground Distribution Lines and Feeders - Operation Labour	25,914	3,887	24,542	3,681	25,800	3,870	27,000	4,050
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	4,314	647	5,868	880	8,600	1,290	8,950	1,343
5050-Underground Sub transmission Feeders - Operation	0	0	0	0	0	0	0	0
5055-Underground Distribution Transformers - Operation	0	0	0	0	250	38	250	38
5060-Street Lighting and Signal System Expense	0	0	0	0	0	0	0	0
5065-Meter Expense	33,479	5,022	46,196	6,929	59,900	8,985	67,750	10,163
5070-Customer Premises - Operation Labour	60,633	9,095	42,833	6,425	45,000	6,750	47,200	7,080
5075-Customer Premises - Materials and Expenses	7,687	1,153	7,363	1,104	9,000	1,350	9,500	1,425
5085-Miscellaneous Distribution Expense	317,078	47,562	335,850	50,377	382,175	57,326	401,700	60,255
5090-Underground Distribution Lines and Feeders - Rental Paid	0	0	0	0	0	0	0	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	3,803	570	3,351	503	3,700	555	3,700	555
5096-Other Rent	0	0	0	0	0	0	0	0
Sub-Total	**600,374**	**90,056**	**639,277**	**95,891**	**733,700**	**110,055**	**778,575**	**116,786**
Maintenance								
5105-Maintenance Supervision and Engineering	11,127	1,669	9,824	1,474	11,100	1,665	11,950	1,793
5110-Maintenance of Buildings and Fixtures - Distribution Stations	0	0	0	0	0	0	0	0
5112-Maintenance of Transformer Station Equipment	0	0	0	0	0	0	0	0
5114-Maintenance of Distribution Station Equipment	36,652	5,498	36,343	5,451	35,100	5,265	39,300	5,895
5120-Maintenance of Poles, Towers and Fixtures	(2,229)	(334)	35,716	5,357	39,600	5,940	44,680	6,702
5125-Maintenance of Overhead Conductors and Devices	89,027	13,354	89,178	13,377	121,200	18,180	143,500	21,525
5130-Maintenance of Overhead Services	50,358	7,554	49,445	7,417	57,150	8,573	67,700	10,155
5135-Overhead Distribution Lines and Feeders - Right of Way	118,543	17,781	166,170	24,925	179,050	26,858	188,100	28,215
5145-Maintenance of Underground Conduit	0	0	0	0	0	0	0	0
5150-Maintenance of Underground Conductors and Devices	6,588	988	3,449	517	10,950	1,643	13,050	1,958
5155-Maintenance of Underground Services	47,563	7,134	39,169	5,875	53,850	8,078	64,550	9,683
5160-Maintenance of Line Transformers	30,037	4,506	31,786	4,768	42,100	6,315	50,250	7,538
5165-Maintenance of Street Lighting and Signal Systems	0	0	0	0	0	0	0	0
5170-Sentinel Lights - Labour	0	0	0	0	0	0	0	0
5172-Sentinel Lights - Materials and Expenses	0	0	0	0	0	0	0	0
5175-Maintenance of Meters	29,255	4,388	28,498	4,275	30,000	4,500	34,000	5,100
5178-Customer Installations Expenses- Leased Property	0	0	0	0	0	0	0	0
5185-Water Heater Rentals - Labour	0	0	0	0	0	0	0	0
5186-Water Heater Rentals - Materials and Expenses	0	0	0	0	0	0	0	0
5190-Water Heater Controls - Labour	0	0	0	0	0	0	0	0
5192-Water Heater Controls - Materials and Expenses	0	0	0	0	0	0	0	0
5195-Maintenance of Other Installations on Customer Premises	0	0	0	0	0	0	0	0
Sub-Total	**416,921**	**62,538**	**489,578**	**73,437**	**580,100**	**87,015**	**657,080**	**98,562**
Billing and Collections								
5305-Supervision	40,412	6,062	39,851	5,978	42,400	6,360	44,900	6,735
5310-Meter Reading Expense	145,366	21,805	145,829	21,874	142,800	21,420	153,200	22,980
5315-Customer Billing	338,215	50,732	350,047	52,507	367,100	55,065	383,950	57,593
5320-Collecting	281,076	42,161	311,898	46,785	322,000	48,300	345,200	51,780
5325-Collecting- Cash Over and Short	149	22	72	11	50	8	50	8
5330-Collection Charges	(32,558)	(4,884)	(37,069)	(5,560)	0	0	0	0
5335-Bad Debt Expense	28,353	4,253	64,729	9,709	29,000	4,350	30,000	4,500
5340-Miscellaneous Customer Accounts Expenses	28,580	4,287	47,819	7,173	47,600	7,140	53,300	7,995
Sub-Total	**829,594**	**124,439**	**923,175**	**138,476**	**950,950**	**142,643**	**1,010,600**	**151,590**

Description	2006 Actual	Allowance for Working Capital	2007 Actual	Allowance for Working Capital	2008 Bridge	Allowance for Working Capital	2009 Test	Allowance for Working Capital
Rate used for Working Capital Allowance		15%		15%		15%		15%
Community Relations								
5405-Supervision	0	0	0	0	0	0	0	0
5410-Community Relations - Sundry	6,767	1,015	9,350	1,402	8,500	1,275	8,100	1,215
5415-Energy Conservation	45,333	6,800	35,204	5,281	0	0	0	0
5420-Community Safety Program	0	0	2,815	422	0	0	1,000	150
5425-Miscellaneous Customer Service and Informational Expenses	8,113	1,217	2,521	378	2,100	315	2,600	390
5505-Supervision	0	0	0	0	0	0	0	0
5510-Demonstrating and Selling Expense	0	0	0	0	0	0	0	0
5515-Advertising Expense	0	0	0	0	0	0	0	0
5520-Miscellaneous Sales Expense	0	0	0	0	0	0	0	0
Sub-Total	**60,213**	**9,032**	**49,890**	**7,483**	**10,600**	**1,590**	**11,700**	**1,755**
Administrative and General Expenses								
5605-Executive Salaries and Expenses	334,839	50,226	108,380	16,257	197,050	29,558	214,350	32,153
5610-Management Salaries and Expenses	40,988	6,148	149,479	22,422	152,225	22,834	165,525	24,829
5615-General Administrative Salaries and Expenses	172,079	25,812	343,969	51,595	424,725	63,709	519,170	77,876
5620-Office Supplies and Expenses	63,479	9,522	67,198	10,080	71,750	10,763	82,450	12,368
5625-Administrative Expense Transferred Credit	0	0	0	0	0	0	0	0
5630-Outside Services Employed	86,849	13,027	57,371	8,606	54,500	8,175	56,800	8,520
5635-Property Insurance	15,058	2,259	40,670	6,101	42,500	6,375	44,200	6,630
5640-Injuries and Damages	24,135	3,620	32,834	4,925	39,000	5,850	40,600	6,090
5645-Employee Pensions and Benefits	(32,050)	(4,807)	0	0	0	0	9,400	1,410
5650-Franchise Requirements	0	0	0	0	0	0	0	0
5655-Regulatory Expenses	60,884	9,133	46,686	7,003	28,310	4,247	90,690	13,604
5660-General Advertising Expenses	0	0	0	0	0	0	0	0
5665-Miscellaneous General Expenses	85,133	12,770	70,765	10,615	67,705	10,156	72,930	10,940
5670-Rent	323	49	323	49	330	50	350	53
5675-Maintenance of General Plant	129,342	19,401	142,926	21,439	144,580	21,687	150,600	22,590
5680-Electrical Safety Authority Fees	8,158	1,224	10,819	1,623	14,500	2,175	16,100	2,415
5685-Independent Market Operator Fees and Penalties	0	0	0	0	0	0	0	0
Sub-Total	**989,218**	**148,383**	**1,071,420**	**160,713**	**1,237,175**	**185,576**	**1,463,165**	**219,475**
Property Taxes								
6105 - Property Taxes	9,751	1,463	9,979	1,497	10,300	1,545	10,600	1,590
Sub-Total	**9,751**	**1,463**	**9,979**	**1,497**	**10,300**	**1,545**	**10,600**	**1,590**
Cost of Power								
4705-Power Purchased	13,690,204	2,053,531	13,817,222	2,072,583	12,877,467	1,931,620	12,997,753	1,949,663
4708-Charges-WMS	1,176,077	176,412	1,202,229	180,334	1,228,676	184,301	1,240,153	186,023
4710-Cost of Power Adjustments	(417,525)	(62,629)	(820,526)	(123,079)	0	0	0	0
4712-Charges-One-Time	0	0	0	0	0	0	0	0
4714-Charges-NW	1,200,338	180,051	1,294,575	194,186	1,212,942	181,941	1,223,657	183,549
4716-Charges-CN	953,083	142,962	861,634	129,245	816,010	122,402	823,277	123,492
4730-Rural Rate Assistance	0	0	0	0	236,284	35,443	238,491	35,774
4750-LV Charges	205,237	30,786	331,411	49,712	495,642	74,346	497,129	74,569
Sub-Total	**16,807,414**	**2,521,112**	**16,686,544**	**2,502,982**	**16,867,021**	**2,530,053**	**17,020,460**	**2,553,069**
WORKING CAPITAL ALLOWANCE TOTAL	**19,713,485**	**2,957,023**	**19,869,862**	**2,980,479**	**20,389,846**	**3,058,477**	**20,952,180**	**3,142,827**

OVERVIEW OF OPERATING REVENUE:

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

Distribution revenues for 2008 and 2009 have been calculated using the rates approved in the OEB's 2008 rate adjustment proceeding in respect of Innisfil Hydro. In particular, delivery rates are based on the OEB's Decision and Order in EB-2007-0845, dated April 21, 2008. Distribution revenue does not include revenue from commodity sales or other pass through costs.

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

Distribution Revenue:

Information related to Innisfil Hydro'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 within Exhibit 3, Tab 2.

Other Revenue:

Other revenues include (for example) Late Payment Charges, Miscellaneous Service Revenues and Retail Services Revenues. 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, Innisfil Hydro 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 (new rates)	Variance from 2008 Bridge
Residential	4,915,132	4,755,054	(160,078)	5,090,883	335,829	5,217,402	126,519	6,131,368	913,966
GS<50	595,079	611,529	16,450	654,721	43,192	681,366	26,645	650,633	(30,733)
GS>50	609,081	603,442	(5,639)	632,138	28,696	635,690	3,552	694,206	58,516
Street Light	35,495	35,477	(18)	39,420	3,943	43,434	4,014	209,262	165,827
Sentinel	5,301	4,808	(493)	4,996	188	4,318	(678)	18,059	13,741
Unmetered Scattered Load	36,198	13,309	(22,889)	24,078	10,769	24,573	495	46,906	22,334
Premarket Opening Variance	-	760,982	760,982	-	(760,982)	-	-	-	-
Total Distribution Revenue	6,196,286	6,784,601	588,315	6,446,236	(338,365)	6,606,782	160,546	7,750,434	1,143,652
Other Revenue									
Late Payment Charges	71,282	86,955	15,673	92,218	5,263	89,542	(2,676)	89,542	-
Specific Service Charges	243,095	222,675	(20,420)	203,893	(18,782)	254,698	50,805	281,143	26,445
Other Revenue	124,484	356,070	231,586	234,467	(121,603)	203,373	(31,094)	120,572	(82,801)
Total Other Revenue	438,861	665,700	226,839	530,578	(135,122)	547,613	17,035	491,257	(56,356)
Total Operating Revenue	6,635,147	7,450,301	815,154	6,976,814	(473,487)	7,154,395	177,581	8,241,691	1,087,296

DISTRIBUTION REVENUE AND VARIANCE ANALYSIS:

Innisfil Hydro's distribution revenue has been calculated using its most recently approved rates. In particular, delivery rates are based on the EB-2007-0845 Rate Order, dated April 21, 2008. As noted above, distribution revenue does not include commodity-related revenue.

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

2006 Board Approved:

Innisfil Hydro's 2006 Board Approved operating revenue was forecast to be $6,635,147, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totaled $6,196,286 or 93.4% of total revenues. Other revenue accounts for the remaining revenue of $438,861.

2006 Actual:

Innisfil Hydro's operating revenue in fiscal 2006 was $7,450,301, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totaled $6,784,601 or 91.1% of total revenues. Other revenue accounts for the remaining revenue of $665,700.

Comparison to 2006 Board Approved:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue was $815,154 higher than the 2006 Board Approved level forecasted. This increase resulted from the setup of the Premarket Opening Variance (PMOV) of $760,982, for the period Jan 2001 to April 2002. The loss was not setup on the balance sheet until 2006 when the 2006 EDR approval verified the collection of this regulatory asset as direction provided by Innisfil Hydro's auditors and further disclosed on Note 6 on the 2006 Audited financial statements. In the Other Revenue category, carrying charges resulting from the regulatory asset accounts from 2002 to present were recorded ($230k).

2007 Actual:

Innisfil Hydro's operating revenue in fiscal 2006 was $6,976,814, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totaled $6,446,236 or 92.4% of total revenues. Other revenue accounts for the remaining revenue of $530,953.

Comparison to 2006 Actual:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue was $473,487 lower than the 2006 Actual revenue. This decrease resulted from the one time revenue of PMOV and several years of carrying charges recognized in 2006, offset by a full year of the 2006 EDR approved rates and increased consumption levels in the residential and general services rate classes.

2008 Bridge Year:

Innisfil Hydro's operating revenue is forecast to be $7,154,395 in fiscal 2008, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $6,606,782 or 92.3% of total revenues. Other revenues accounts for the remaining revenue of $547,613.

Comparison to 2007 Actual:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is expected to be $177,581 above the actual year level in fiscal 2007. This increase is the result of forecasted normalized growth in customers and consumption, which has a positive effect on distribution revenue. In the Other Revenue category, Innisfil Hydro is reclassifying the Collection of account charge from account 5330 to account 4225 in the Specific Service Charges category ($35k) effective January 2008 and reclassified Returned Cheque charge from the Other Revenue category ($12k). The Other Revenue has decreased due to a lower than prior year interest rates ($15k) and reclassifying Returned Cheque charge to the Specific Service charge category ($12k).

2009 Test Year:

Innisfil Hydro's operating revenue is forecast to be $8,241,691 in fiscal 2009, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $7,750,434 or 94.0% of total revenues. Other revenue accounts for the remaining revenue of $491,257.

Comparison to 2008 Bridge Year:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is expected to be $1,143,652 above the bridge year level in fiscal 2008. This increase is the result of new distribution rates factoring the revenue deficiency Exhibit 7, Tab 1, Schedule 1, of $1,071,765 and forecasted load and customer growth $71,000. This is offset by reduced other revenue due to decreased interest income $61,000 and lost net margin $30,000 from Innisfil Hydro's affiliate Innisfil Energy Services for customer service services partially offset by the increase of the Account set up charge from $15 to the standard rate of $30 showing in the Specific service charges category $25,000.

DISTRIBUTION REVENUE DATA BY CLASS:

2006 Board Approved	**Customers (Year end)**	**Consumption/Demand (kWh/kW)**	**Distribution Revenues $**	**Unit Revenues $/kWh/kW**
Residential	12,670	159,677,128	4,915,132	0.0139
GS<50	771	25,166,664	595,079	0.0106
GS>50	74	107,903	609,081	2.7878
Street Light	2,309	3,929	35,495	0.0105
Sentinel	183	325	5,301	6.6053
Unmetered Scattered Load	117	736,355	36,198	4.6121
Total	16,124		6,196,286	

2006 Actual	**Customers (Year end)**	**Consumption/Demand (kWh/kW)**	**Distribution Revenues $**	**Unit Revenues $/kWh/kW**
Residential	12,949	147,617,301	4,755,054	0.0139
GS<50	903	27,543,435	611,529	0.0106
GS>50	67	118,220	603,442	2.7878
Street Light	2,490	4,028	35,477	0.0105
Sentinel	184	367	4,808	6.6053
Unmetered Scattered Load	-	-	13,309	4.6121
Total	16,593		6,023,619	

2007 Actual	**Customers (Year end)**	**Consumption/Demand (kWh/kW)**	**Distribution Revenues $**	**Unit Revenues $/kWh/kW**
Residential	13,132	152,967,169	5,090,883	0.0140
GS<50	831	28,694,771	654,721	0.0107
GS>50	72	118,203	632,138	2.8129
Street Light	2,588	4,157	39,420	0.0106
Sentinel	188	349	4,996	6.6647
Unmetered Scattered Load	85	562,039	24,078	4.6536
Total	16,896		6,446,236	

2008 Bridge	**Customers (Year end)**	**Consumption/Demand (kWh/kW)**	**Distribution Revenues $**	**Unit Revenues $/kWh/kW**
Residential	13,321	152,989,159	5,217,402	0.0140
GS<50	829	29,753,563	681,366	0.0107
GS>50	72	115,822	635,690	2.8045
Street Light	2,697	4,688	43,434	4.6396
Sentinel	190	347	4,318	6.6447
Unmetered Scattered Load	85	562,039	24,573	0.0106
Total	17,194		6,606,782	

2009 Test	**Customers (Year end)**	**Consumption/Demand (kWh/kW)**	**Distribution Revenues $**	**Unit Revenues $/kWh/kW**
Residential	13,512	153,846,698	6,131,368	0.0196
GS<50	827	31,019,894	650,633	0.0101
GS>50	72	115,534	694,206	3.4070
Street Light	2,810	4,924	209,262	21.9540
Sentinel	193	344	18,059	22.1992
Unmetered Scattered Load	85	562,039	46,906	0.0413
Total	17,499		7,750,434	

LOAD FORECAST AND METHODOLOGY

Innisfil Hydro weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on multifactor regression model that incorporates historical load, weather, and economic data. Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Finally, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression model. The forecast of customers by rate class is determined using time-series econometric methodologies. For those rate classes that use kW for the distribution volumetric billing determinant an adjustment factor is applied to class energy forecast based on the historical relationship between kW and kWh. The following will explain the forecasting process in more detail.

Purchased KWh Load Forecast

The forecast of total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (heating and cooling degree days), economic output (GDP growth), load characteristics (peak hours per month) and calendar variables (days in month, seasonal). The regression model uses monthly kWh and monthly values of independent variables from January 2002 to December 2007 to determine the monthly regression coefficients.

Data for Innisfil Hydro's total system load is available as far back as January 2002 which provides 72 data monthly data points and this is a reasonable data set for use in a multiple regression analysis. Based on the recent global activity surrounding climate change historical weather data is showing that there is a warming of the global climate system. In this regard it is Innisfil Hydro’s view that it is appropriate to review the impact of weather since 2002 on the energy usage and then determine the average weather conditions from 2002 to 2007 which would be applied in the forecasting process to determine a weather normalized forecast.

The multifactor regression model has determined primary driver of year-over-year changes in Innisfil Hydro's load growth are economic conditions and weather. Both of these effects are captured within the multifactor regression model.

Economic growth – which encompasses both growth in the Innisfil Hydro's customer base as well as general economic conditions is captured in the model using population statistic and an index of economic output, Ontario Real Gross Domestic Product ("GDP").

Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both Heating Degree Days (i.e. a measure of coldness in winter) and Cooling Degree Days i.e. a measure of summer heat) are modeled.

The third main factor determining energy use in the monthly model can be classified as "calendar factors". For example, the number of days in a particular month will impact energy use. The modeling of purchased energy uses number of days in the month, hours of peak load in a month, and two "flag" variables – one to capture the typically lower usage in the spring and fall months, and the other to capture the impact of the 2003 August blackout on energy use in that month.

The process of developing a model of energy usage involves estimating multifactor models using different input variables to determine the best fit. Using stepwise regression techniques different explanatory variables were tested with the ultimate model being determined both by model statistics and by forecast accuracy. The model chosen as the best predictor of kWh purchased by Innisfil Hydro is as follows

Innisfil Hydro Monthly Predicted kWh Purchases

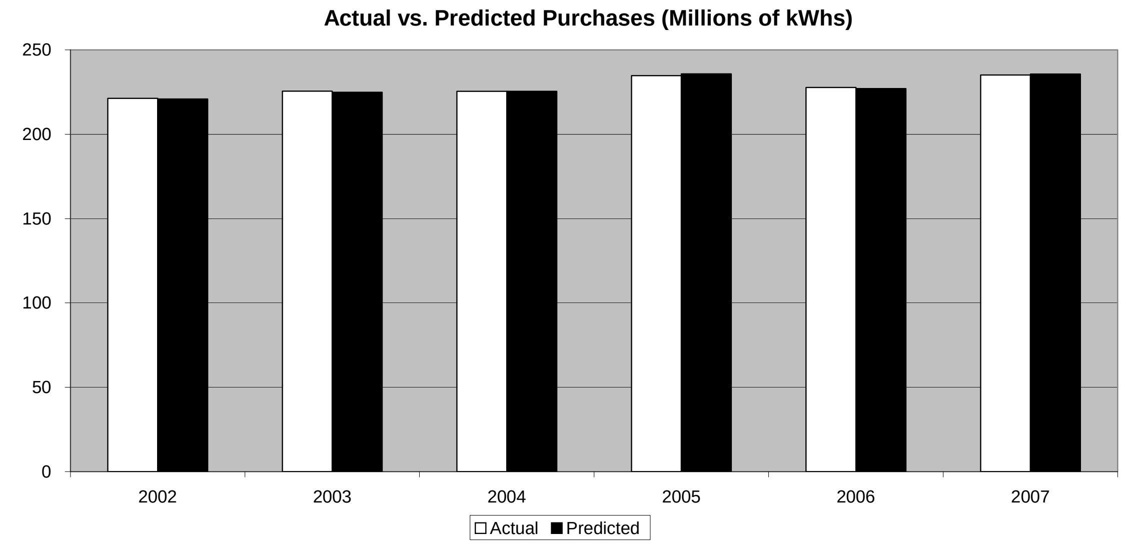
= Heating Degree Days * 14,142
+ Cooling Degree Days * 27,726
+ Ontario Real GDP Monthly Index * 18795
+ Number of Peak Hours * (3,879)
+ Number of Days in the Month * 565,454
+ Population * 260
+ Spring Fall Flag * (909,299)
+ Aug 03 Blackout Flag * (1,183,260)
+ Constant of (12,154,736).

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix A.

The sources of data for the various data points are:

a) Environment Canada website for monthly heating degree day and cooling degree information. From 2002 to 2007, data from the Pearson Airport weather stations was used.
b) The 2008, 2009 and 2010 rate application (EB-2007-0680) for Toronto Hydro Electric System Ltd provided the Ontario real GDP monthly index and;.
c) Population data was provided from the Town of Innisfil census
d) The calendar provided information related to number of days in the month, number of peak hours and the spring/fall flag.

The annual results of the above prediction formula compared to the actual annual purchases from 2002 to 2007 are shown in the chart below. The prediction formula has a statistical R^2 of 98.5% which generally indicates the formula has a very good fit to the actual data set.



The following table outlines the data that supports the above chart. In addition, the weather normalized forecast of total system purchases for Innisfil Hydro in provided for 2008 and 2009.

Table 4
IHDSL's Total System Purchases

	Actual	Predicted	% Difference
2002	221	221	-0.16%
2003	226	225	-0.32%
2004	225	225	0.00%
2005	235	236	0.45%
2006	228	227	-0.25%
2007	235	236	0.25%
2008 (WN)		238	
2009 (WN)		240	

The forecasted weather normalized amount for 2008 and 2009 is determined by using a forecast of the dependent variables in the prediction formula on a monthly basis. In order to incorporate weather normal conditions, the average monthly heating degree days and cooling degree days which has occurred from 2002 to 2007 is applied in the prediction formula. The details on the average monthly heating degree days and cooling degree days is shown in Appendix A.

Billed KWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by a historical loss factor. As outlined in the table below, historically the IHDSL loss factor on average has been 5.8%

Table 5
Historical Loss Factor

(GWh)	Actual Purchases	Actual Billed	Loss Factor
2002	221	200	10.9%
2003	226	213	5.9%
2004	225	217	3.9%
2005	235	225	4.2%
2006	228	216	5.2%
2007	235	224	4.9%
Average			5.8%

With this average loss factor the total weather normalized billed energy will be 225.1 (GWh) for 2008 (i.e. 238.2/1.058) and 227.2 (GWh) for 2009 (i.e. 240.4/1.058)

Billed KWh Load Forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed energy amount is known this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available as shown in the following table.

Table 6
Historical Customer/Connection Data

	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Number of Customers/Connection							
2002	12,227	841	73	2,107	177	0	15,425
2003	12,409	880	73	2,196	181	0	15,739
2004	12,670	888	74	2,309	183	0	16,124
2005	12,821	890	82	2,371	189	0	16,353
2006	12,949	903	67	2,490	184	0	16,593
2007	13,132	831	72	2,588	188	85	16,896

From the historical customer/connection data the growth rate in customer/connection can be evaluated which is provided on the following table. For applicable classes, the geometric mean growth rate has also been shown.

Table 7
Growth Rate in Customer/Connections

	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Loads
Growth Rate in Customer/Connection						
2002						
2003	1.49%	4.64%	0.00%	4.22%	2.26%	
2004	2.10%	0.91%	1.37%	5.15%	1.10%	
2005	1.19%	0.23%	10.81%	2.69%	3.28%	
2006	1.00%	1.46%	-18.29%	5.02%	-2.65%	
2007	1.41%	-7.97%	7.46%	3.94%	2.17%	
Geometric Mean	1.44%	-0.24%	-0.28%	4.20%	1.21%	N/A

In most cases where the geometric mean is determined, the resulting geometric mean is applied to the 2007 customer/connection numbers to determine the forecast of customer/connections in 2008 and 2009. However, for Unmetered Loads the number of connections for 2008 and 2008 is held constant at the 2007 level.

Table 8
Customer/Connection Forecast

	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Forecast number of Customers/Connection							
2008	13,321	829	72	2,697	190	85	17,194
2009	13,512	827	72	2,810	193	85	17,499

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. The following table provides the average annual usage per customer by rate class from 1996 to 2007 where data is available.

Table 9
Historical Annual Usage per Customer

	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Loads
Annual kWh Usage Per Customer/Connection						
2002	11,270	25,662	532,424	556	745	0
2003	11,944	28,508	528,275	432	751	0
2004	12,008	30,692	489,601	537	739	0
2005	12,130	31,577	487,645	620	697	0
2006	11,400	30,502	591,776	582	716	0
2007	11,648	34,530	560,031	579	669	6,612

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed which is provided on the following table. The geometric mean growth rate has also been shown.

Table 10
Growth Rate in Usage Per Customer/Connection

	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Loads
Growth Rate in Usage Per Customer/Connection						
2002						
2003	5.97%	11.09%	-0.78%	-22.17%	0.75%	
2004	0.54%	7.66%	-7.32%	24.26%	-1.64%	
2005	1.02%	2.88%	-0.40%	15.38%	-5.62%	
2006	-6.02%	-3.40%	21.35%	-6.07%	2.69%	
2007	2.18%	13.21%	-5.36%	-0.66%	-6.47%	
Geometric Mean	0.66%	6.12%	1.02%	0.81%	-2.12%	N/A

For the forecast of usage per customer/connection the historical geometric mean was used for all classes except Unmetered Load. For the Unmetered Load class the 2007 usage per customer/connection was assumed to be held constant for 2008 and 2009.

Table 11
Forecast Annual kWh Usage per Customer/Connection

	Residential	Service < 50 kW	Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Loads
Forecast Annual kWh Usage per Customers/Connection						
2008	11,726	36,642	565,721	583	655	6,612
2009	11,803	38,884	571,470	588	641	6,612

With regards to reflecting CDM savings in the forecast, it is interesting to note in Table 9, the 2006 usage per customer in the Residential class is the second lowest usage per customer over the period 2002 to 2007. The 2006 value is significantly impacting the growth rate in residential usage per customer to be only 0.66%. Since most of Innisfil Hydro's CDM programs have been targeted to the Residential class it appears that the programs are impacting on usage, particularly in 2006, and this suggest by using usage per customer in the forecast, the forecast will reflect the impacts of CDM.

With the preceding information the non-normalized weather billed energy forecast can be determine by applying the forecast number of customer/connection from Table 8 by the forecast of annual usage per customer/connection from Table 11. The resulting non-normalized weather billed energy forecast is shown in the following table.

Table 12
Non-normalized Weather Billed Energy Forecast

	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Non-normalized Weather Billed Energy Forecast (GWh)							
2008	156.2	30.4	40.6	1.6	0.1	0.6	229.5
2009	159.5	32.2	40.9	1.7	0.1	0.6	234.9

The non-normalized weather billed energy forecast has been determined but this needs to be adjusted in order to be aligned with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast is 225.1 (GWh) for 2008 and 227.2 (GWh) for 2009.

The difference between the non-normalized and normalized forecast is 4.4 GWh in 2008 (i.e. 229.5 – 225.1) and 7.7 GWh in 2009 (i.e. 234.9 – 227.1). This difference will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One for Innisfil Hydro for the cost allocation study, which has been used to support this rate application, it was determined the weather sensitivity by rate classes is as follows.

Table 13
Weather Sensitivity by Rate Class

Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Loads
Weather Sensitivity					
100%	100%	65%	0%	0%	0%

As a result, the difference between to the non-normalized and normalized forecast has been assigned on a prorate basis to each rate classes based on the above level of weather sensitivity. The following table outlines how the weather sensitive rate classes have been adjusted to align the non-normalized forecast with the normalized forecast.

Table 14
Alignment of Non-normal to Weather Normal Forecast

	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Non-normalized Weather Billed Energy Forecast (GWh)							
2008	156.2	30.4	40.6	1.6	0.1	0.6	229.5
2009	159.5	32.2	40.9	1.7	0.1	0.6	234.9
Adjustment for Weather							
2008	-3.2	-0.6	-0.5	0.0	0.0	0.0	-4.4
2009	-5.6	-1.1	-0.9	0.0	0.0	0.0	-7.7
Weather Normalized Billed Energy Forecast							
2008	153.0	29.8	40.1	1.6	0.1	0.6	225.1
2009	153.8	31.0	40.0	1.7	0.1	0.6	227.2

Billed KW Load Forecast

There three rate classes that charge volumetric distribution on per kW basis. These include General Service > 50 kW, Streetlights and Sentinel Lights. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these classes is based on a review of the historical ratio of kW to kWhs and applying the average ratio to the forecasted kWh to produce the required kW.

The following table outlines the annual demand units by applicable rate class.

Table 15
Historical Annual kW per Applicable Rate Class

	General Service > 50 kW	Streetlights	Sentinel Lights
2002	91,181	3,267	369
2003	118,027	3,652	378
2004	113,538	3,750	376
2005	115,408	3,925	365
2006	118,220	4,028	367
2007	118,203	4,157	349

The following is the historical ratio of kW/kWh as well as the average ratio.

Table 16
Historical kW/KWh Ratio per Applicable Rate Class

	General Service > 50 kW	Streetlights	Sentinel Lights
2002	0.2346%	0.2790%	0.2797%
2003	0.3061%	0.3845%	0.2781%
2004	0.3134%	0.3022%	0.2782%
2005	0.2886%	0.2670%	0.2771%
2006	0.2982%	0.2777%	0.2787%
2007	0.2931%	0.2776%	0.2773%
Average	0.2890%	0.2980%	0.2782%

The average ratio was applied to the weather normalized billed energy forecast in Tables 14 to provide the forecast of kW by rate class as shown below. The following outlines the forecast of kW for the applicable rate classes.

Table 17
kW Forecast by Applicable Rate Class

	General Service > 50 kW	Streetlights	Sentinel Lights
2008	115,822	4,688	347
2009	115,534	4,924	344

Summary of Forecast Data

	2006 Board Approved	2006 Actual	2007 Actual	2008 Weather Normal	2009 Weather Normal
Actual kWh Purchases		227,671,082	235,121,981		
Predicted kWh Purchases	212,499,854	227,100,692	235,700,826	238,209,375	240,434,436
% Difference		-0.25%	0.25%		
Billed kWh	212,499,854	216,391,743	224,169,495	225,080,268	227,182,694
By Class					
Residential					
Customers	12,670	12,949	13,132	13,321	13,512
kWh	147,659,838	147,617,301	152,967,169	152,989,159	153,846,698
General Service < 50 kW					
Customers	771	903	831	829	827
kWh	24,497,971	27,543,435	28,694,771	29,753,563	31,019,894
General Service > 50 kW					
Customers	74	67	72	72	72
kWh	38,328,393	39,648,974	40,322,203	40,077,819	39,978,179
kW	107,765	118,220	118,203	115,822	115,534
Streetlights					
Connections	2,309	2,490	2,588	2,697	2,810
kWh	1,172,763	1,450,335	1,497,459	1,573,009	1,652,371
kW	3,713	4,028	4,157	4,688	4,924
Sentinel Lights					
Connections	183	184	188	190	193
kWh	136,591	131,698	125,854	124,678	123,512
kW	360	367	349	347	344
Unmetered Loads					
Connections	117	0	85	85	85
kWh	704,298	0	562,039	562,039	562,039
Total					
Customer/Connections	16,124	16,593	16,896	17,194	17,499
kWh	212,499,854	216,391,743	224,169,495	225,080,268	227,182,694
kW from applicable classes	111,838	122,615	122,709	120,857	120,802

Appendix A

Monthly Data Used in Regression Analysis

	Purchased kWh without losses	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring Fall Flag	Population	Number of Peak Hours	Blackout Flag	Predicted Purchases
Jan-02	21,291,130	572.2	0	122.60	31	0	27,293	352	0	21,500,868
Feb-02	19,257,284	540.2	0	123.20	28	0	27,434	320	0	19,524,356
Mar-02	19,877,128	545.6	0	123.80	31	1	27,576	320	0	20,435,663
Apr-02	16,620,835	329.5	8.3	124.00	30	1	27,717	352	0	16,960,113
May-02	16,408,007	227.5	7.8	124.20	31	1	27,859	352	0	16,110,461
Jun-02	15,901,100	36.2	70	124.40	30	0	28,000	320	0	15,639,241
Jul-02	18,859,131	0	192.4	124.90	31	0	28,142	352	0	19,007,671
Aug-02	17,578,685	0.2	142.7	125.40	31	0	28,283	336	0	17,739,278
Sep-02	15,578,678	21.8	87.6	125.90	30	1	28,425	320	0	15,152,856
Oct-02	17,377,963	292.2	10	126.10	31	1	28,566	352	0	17,306,078
Nov-02	19,397,298	445	0	126.20	30	1	28,708	336	0	18,723,666
Dec-02	23,067,357	619.4	0	126.40	31	0	28,849	320	0	22,768,581
Jan-03	25,336,272	814.5	0	126.80	31	0	28,991	352	0	25,447,785
Feb-03	22,647,764	699	0	127.20	28	0	29,132	320	0	22,286,691
Mar-03	21,590,452	581.1	0	127.50	31	1	29,274	336	0	21,385,194
Apr-03	17,966,170	372.5	2.4	127.40	30	1	29,415	336	0	17,971,445
May-03	15,547,303	177.9	0	127.20	31	1	29,557	336	0	15,751,244
Jun-03	15,421,454	43.4	52.9	127.00	30	0	29,698	336	0	15,693,015
Jul-03	17,138,347	0.2	118.3	126.70	31	0	29,798	352	0	17,420,490
Aug-03	16,676,168	2	128	126.40	31	0	29,898	320	1	16,676,168
Sep-03	14,708,981	54.9	24	126.00	30	1	29,999	336	0	14,204,371
Oct-03	17,244,742	276	0	126.40	31	1	30,099	352	0	17,203,839
Nov-03	18,824,954	398.5	0	126.90	30	1	30,199	320	0	18,531,230
Dec-03	22,467,921	561.5	0	127.30	31	0	30,299	336	0	22,280,184
Jan-04	26,590,240	849.1	0	127.40	31	0	30,399	336	0	26,375,228
Feb-04	21,970,083	631.7	0	127.50	29	0	30,499	320	0	22,260,437
Mar-04	20,655,664	487.3	0	127.70	31	1	30,600	368	0	20,283,098
Apr-04	17,228,367	331.5	0	128.30	30	1	30,700	336	0	17,676,017
May-04	15,828,220	158.9	8.6	128.90	31	1	30,800	320	0	16,139,724
Jun-04	15,165,016	44.2	31.6	129.60	30	0	30,900	352	0	15,413,667
Jul-04	16,840,567	3.6	86.4	130.20	31	0	30,931	336	0	17,004,972
Aug-04	16,501,963	12.8	59.6	130.90	31	0	30,962	336	0	16,413,166
Sep-04	15,502,861	30	41.2	131.50	30	1	30,993	336	0	14,690,954
Oct-04	16,523,670	226.3	1.5	131.90	31	1	31,023	320	0	17,010,499
Nov-04	18,529,386	379.1	0	132.20	30	1	31,054	352	0	18,453,165
Dec-04	24,127,220	643.4	0	132.50	31	0	31,085	336	0	23,740,468
Jan-05	26,157,026	770	0	132.60	31	0	31,116	320	0	25,604,196
Feb-05	21,848,395	616.4	0	132.80	28	0	31,147	320	0	21,747,648
Mar-05	21,979,572	608.6	0	133.00	31	1	31,178	352	0	22,311,868
Apr-05	17,068,753	306.8	0	133.20	30	1	31,208	336	0	17,551,064
May-05	15,947,605	189.4	0.8	133.40	31	1	31,239	336	0	16,490,065
Jun-05	18,108,542	8.9	146.3	133.70	30	0	31,270	352	0	18,268,001
Jul-05	19,717,880	0	188.7	133.90	31	0	31,288	320	0	20,016,304
Aug-05	18,367,504	0.2	140.7	134.20	31	0	31,305	352	0	18,574,301
Sep-05	15,759,038	22.6	52.1	134.50	30	1	31,323	336	0	15,030,711
Oct-05	16,932,624	220.2	7.6	134.60	31	1	31,340	320	0	17,226,446
Nov-05	18,862,653	388.4	0	134.70	30	1	31,358	352	0	18,710,534
Dec-05	23,957,691	665.3	0	134.90	31	0	31,375	320	0	24,234,181

Residential
General Servi
General Servi

Jan-06	22,669,357	551.8	0	135.20	31	0	31,393	336	0	22,575,791
Feb-06	21,313,440	604.3	0	135.40	28	0	31,410	320	0	21,693,866
Mar-06	21,380,358	516.6	0	135.70	31	1	31,428	368	0	21,063,078
Apr-06	16,821,252	293.3	0	136.00	30	1	31,445	304	0	17,600,020
May-06	16,127,722	136.9	26	136.30	31	1	31,463	352	0	16,498,299
Jun-06	17,113,803	19.5	73.6	136.60	30	0	31,480	352	0	16,511,259
Jul-06	19,766,278	0	167.3	136.90	31	0	31,524	320	0	19,540,799
Aug-06	17,967,203	4.2	101.6	137.20	31	0	31,568	352	0	17,671,464
Sep-06	15,425,394	80.9	12.9	137.40	30	1	31,612	320	0	14,962,231
Oct-06	17,838,576	288.3	1.1	137.70	31	1	31,656	336	0	18,086,091
Nov-06	19,022,965	382.2	0	138.00	30	1	31,700	352	0	18,773,817
Dec-06	22,224,734	500.5	0	138.30	31	0	31,744	304	0	22,123,977
Jan-07	23,677,868	647.1	0	138.60	31	0	31,787	352	0	24,029,442
Feb-07	23,283,721	740.1	0	138.90	28	0	31,831	320	0	23,789,620
Mar-07	21,733,107	546.7	0	139.10	31	1	31,875	352	0	21,732,561
Apr-07	18,120,440	356.4	0	139.40	30	1	31,919	320	0	18,618,078
May-07	15,973,436	136.4	22.4	139.70	31	1	31,963	352	0	16,585,462
Jun-07	17,425,817	16.5	99.2	140.00	30	0	32,007	336	0	17,441,020
Jul-07	18,060,431	3.2	106.1	140.20	31	0	32,060	336	0	18,027,145
Aug-07	18,759,168	5.2	141	140.50	31	0	32,114	352	0	18,981,982
Sep-07	16,054,805	36.9	47.5	140.80	30	1	32,167	304	0	15,569,074
Oct-07	16,792,560	137.7	19.8	141.10	31	1	32,220	352	0	16,624,952
Nov-07	20,294,980	462.5	0	141.40	30	1	32,274	352	0	20,122,547
Dec-07	24,945,649	630.7	0	141.60	31	0	32,327	304	0	24,178,941
Jan-08		701	0	141.90	31	0	32,380	352	0	25,004,446
Feb-08		639	0	142.20	29	0	32,434	320	0	23,138,066
Mar-08		548	0	142.50	31	1	32,487	304	0	22,154,846
Apr-08		332	2	142.70	30	1	32,540	352	0	18,415,877
May-08		171	11	143.00	31	1	32,594	336	0	17,046,891
Jun-08		28	79	143.30	30	0	32,647	336	0	17,272,716
Jul-08		1	143	143.60	31	0	32,701	352	0	19,196,677
Aug-08		4	119	143.90	31	0	32,756	320	0	18,709,265
Sep-08		41	44	144.10	30	1	32,810	336	0	15,643,095
Oct-08		240	7	144.40	31	1	32,865	352	0	17,938,344
Nov-08		409	0	144.70	30	1	32,919	304	0	19,786,355
Dec-08		603	0	145.00	31	0	32,974	336	0	23,902,796
Jan-09		701	0	145.30	31	0	33,028	336	0	25,298,795
Feb-09		639	0	145.50	28	0	33,082	304	0	22,865,364
Mar-09		548	0	145.80	31	1	33,137	352	0	22,199,561
Apr-09		332	2	146.10	30	1	33,191	320	0	18,773,151
May-09		171	11	146.40	31	1	33,246	320	0	17,342,367
Jun-09		28	79	146.70	30	0	33,300	352	0	17,444,315
Jul-09		1	143	146.90	31	0	33,354	352	0	19,428,476
Aug-09		4	119	147.20	31	0	33,409	320	0	18,941,063
Sep-09		41	44	147.50	30	1	33,463	336	0	15,876,773
Oct-09		240	7	147.80	31	1	33,518	336	0	18,234,101
Nov-09		409	0	148.10	30	1	33,572	320	0	19,957,953
Dec-09		603	0	148.30	31	0	33,627	352	0	24,072,516

SUMMARY OF OTHER DISTRIBUTION REVENUE

Other Distribution Revenue	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 Actual
4080-SSS Admin	42,122	42,727	605	43,173	446	42,950	(223)	42,950	-
4082-Retail Services Revenues	13,345	14,261	916	21,475	7,214	24,909	3,434	24,909	-
4084-Service Transaction Requests (STR)	40	1,300	1,260	1,420	120	1,360	(60)	1,360	-
4090-Electric Services Incidental to Energy	-	-	-	-	-	-	-	-	-
4205-Interdepartmental Rents	-	-	-	-	-	-	-	-	-
4210-Rent from Electric Property	126,456	145,439	18,983	144,984	(455)	145,208	224	145,208	-
4215-Other Utility Operating Income	-	-	-	-	-	-	-	-	-
4220-Other Electric Revenues	-	-	-	-	-	-	-	-	-
4225-Late Payment Charges	71,282	86,955	15,673	92,218	5,263	89,542	(2,676)	89,542	-
4230-Sales of Water and Water Power	-	-	-	-	-	-	-	-	-
4235-Miscellaneous Service Revenues	116,639	77,236	(39,403)	58,898	(18,338)	109,490	50,592	135,935	26,445
4375-Revenues from Non-Utility Operations	52,380	52,672	292	209,732	157,060	212,597	2,865	169,431	(43,166)
4380-Expenses of Non-Utility Operations	(30,628)	(30,456)	172	(177,925)	(147,469)	(190,096)	(12,171)	(169,431)	20,665
4385-Non-Utility Rental Income	-	-	-	-	-	-	-	-	-
4390-Miscellaneous Non-Operating Income	17,008	10,360	(6,648)	19,468	9,108	7,053	(12,415)	7,053	-
4405-Interest and Dividend Income	30,217	265,206	234,989	117,510	(147,696)	104,600	(12,910)	44,300	(60,300)
Total	438,861	665,700	226,839	530,953	(134,747)	547,613	16,660	491,257	(56,356)

MATERIALITY ANALYSIS ON OTHER DISTRIBUTION REVENUE:

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 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	$4,455,005	$4,848,122	$5,298,080	$5,912,554
Materiality Threshold	$44,550	$48,481	$52,980	$59,126

To allow for the most detailed review of materiality on Other Distribution Revenue, Innisfil Hydro has selected the lowest materiality threshold of $44,550. Innisfil 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
4235. Miscellaneous Service Revenues	$116,639	$77,236	($39,403)
4405. Interest and Dividend Income	$30,217	$265,206	$234,989

Explanation:

The variance resulting from account 4235 Miscellaneous Service Revenues is due to the Collection of account charge is being recorded in the APH account 5330 until 2008. The variance resulting from account 4405 Interest Income is due to carrying charges being recorded for regulatory assets from 2002 to 2006 in 2006.

2006 ACTUAL TO 2007 ACTUAL

Account	2006 Actual	2007 Actual	Variance
4375. Revenues from Non-Utility Operations	$52,672	$209,732	$157,060
4380. Expenses from Non-Utility Operations	($30,456)	($177,925)	($147,469)
4405. Interest and Dividend Income	$265,206	$117,510	($147,696)

Explanation:

The variance resulting in account 4375 and 4380 Non-Utility Operations is due to account 4375 includes funds received from the Ontario Power Authority for OPA-funded Conservation and Demand Management Programs introduced and delivered in 2007. The revenues in USoA Account 4375 are offset by expenses in the amount of $(152,827) booked to USoA Account 4380.

The variance resulting in account 4405 Interest and Dividend Income is due to onetime catch up of carrying charges from regulatory accounts that was recorded in 2006, see variance note above and the declining regulatory asset account balance due to the ongoing recovery.

2007 ACTUAL TO 2008 ACTUAL

Account	2007 Actual	2008 Bridge	Variance
4235. Miscellaneous Service Revenues	$58,898	$109,490	$50,592

Explanation:

The variance resulting in account 4235 is due to Collection Account ($35k) and Returned Cheque ($12k) charge being reclassified from accounts 5330 and 4390 respectively to 4235 effective January 2008.

2008 BRIDGE TO 2009 TEST YEAR

Account	2008 Bridge	2009 Test	Variance
4235. Miscellaneous Service Revenues	$109,490	$135,935	$26,445
4375. Revenues from Non-Utility Operations	$212,597	$169,431	($43,166)
4380. Expenses from Non-Utility Operations	($190,096)	($169,431)	$20,665
4405. Interest and Dividend Income	$104,600	$44,300	($60,300)

Explanation:

The variance resulting in account 4235 is due to increasing the Account set up charge from $15 to $30 to better reflect the approximate cost based on the standard fee in the 2006 EDR.

The variance resulting in account 4375 and 4380 is due to the discontinuation of providing customer service services to our affiliate Innisfil Energy Services Limited. The services provided by Innisfil Hydro's Customer Service reps is in conflict with the Affiliate Relationship Code and required discontinuation. It is estimated the service will be discontinued by the end of 2008. OPA-funded programming for the 2009 Test Year is estimated based on 2007 and 2008 results. Provision for related revenues and expenses has been made in this Application for $169,431 respectively.

The variance resulting in account 4405 is due to Innisfil Hydro going from a cash position to a debt position to fund the operations and capital expenditures in 2009.

RATE OF RETURN ON OTHER DISTRIBUTION REVENUE:

Other distribution revenues do not include a rate of return.

DESCRIPTION OF REVENUE SHARING:

Innisfil Hydro does not have a revenue sharing practice in place.

Exhibit	Tab	Schedule	Appendix	Contents
4 – Operating Costs				
	1			**Overview**
		1		Overview of Operating Costs
	2			**OM&A Costs**
		1		OM&A Detailed Costs Table
		2		Variance Analysis on OM&A
		3		Materiality Analysis on OM&A
		4		Shared Services
		5		Corporate Cost Allocation
		6		Purchase of Services
		7		Employee Compensation, Pension Expense and Post Retirement Benefits
		8		Depreciation, Amortization and Depletion
		9		Loss Adjustment Factor
	3			**Income Tax, Large Corporation Tax**
		1		Tax Calculations
		2		Interest Expense
		3		Capital Cost Allowance (CCA)

OVERVIEW OF OPERATING COSTS:

Operating Costs:

The operating costs presented in this Exhibit represent the annual expenditures required to sustain Innisfil Hydro's distribution operations. Innisfil Hydro follows the OEB's Accounting Procedures Handbook (the "APH") in distinguishing work performed between operations and maintenance. A summary of Innisfil Hydro's operating costs for the 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Bridge Year and the 2009 Test Year including the determination of the variance amount for analysis, in accordance with the Filing Requirements, is provided in Table 1 below.

Table 1
Determination of Materiality Level based on
OM&A Costs

Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
OM&A					
Operation	494,922	600,374	639,277	733,700	778,575
Maintenance	452,465	416,921	489,578	580,100	657,080
Billing and Collections	808,784	829,594	923,175	950,950	1,010,600
Community Relations	8,290	60,213	49,890	10,600	11,700
Administrative & General Expenses	1,216,272	989,218	1,071,420	1,237,175	1,463,165
Taxes other than income taxes	12,192	9,751	9,979	10,300	10,600
Amortization Expenses	1,454,453	1,548,934	1,664,804	1,775,255	1,980,834
Total OM&A Costs	4,447,378	4,455,005	4,848,122	5,298,080	5,912,554
Determination of Variance Amt (1%)	44,474	44,550	48,481	52,981	59,126

Detailed information with respect to OM&A costs and variances, arranged by USoA account, is provided at Exhibit 4, Tab 2, Schedule 3.

The variance used to determine the OM&A accounts requiring analysis has been prescribed by the Filing Requirements as 1% of total distribution expenses before PILs. Innisfil Hydro has adopted a variance analysis threshold of $44,474, being the lowest of the variances among the years under review.

OM&A Costs:

OM&A costs in this Exhibit represent Innisfil Hydro's integrated set of asset management plan and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and government direction; and to maintain distribution business service quality and reliability at targeted performance levels. OM&A costs also include providing services to customers connected to Innisfil Hydro's distribution system, and meeting the requirements of the OEB's Standard Supply Service Code and Retail Settlement Code.

The proposed OM&A expenditures for the 2009 Test Year are the result of a business planning and work prioritization process that ensures that the most appropriate, cost effective solutions are put in place.

Innisfil Hydro is proposing recovery of 2009 Test Year OM&A costs of $5,912,554 plus PILs of $596,367.

OM&A Budgeting Process Used by Innisfil Hydro:

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

- **Operating Work plans:**

Each department Manager is responsible for the preparation of the departmental budget. The following directives are provided to each manager and director:

- All department budgets are to be built using a "bottom up" approach, which requires each functional area, within Innisfil Hydro, to build work plans that identify resources, including labour, vehicles, materials and other third party costs that are required to execute the work plans. This approach ensures that budgets are developed based on the actual work to be completed during the fiscal year, as opposed to a historical costing approach;
- Where applicable, Activity Based Costing work order methodology is to be used in the creation of work plans; and

- Significant variances from prior years must be explained and documented.

- **Payroll-specific procedure:**

- Each department manager confirms the headcount, projected overtime or pay differentials for each employee;

- Finance consolidated this information into a payroll database where the employee information is fully costed and incorporated into the budget database.

Income Tax, Large Corporation Tax and Ontario Capital Taxes:

Innisfil Hydro is subject to the payment of PILs under Section 93 of the *Electricity Act, 1998*, as amended.

Table 2
Summary of Income Taxes

Description	2006 Board Approved	2008 Bridge	2009 Test
Income Taxes	723,905	435,260	575,915
Large Corporation Tax		0	0
Ontario Capital Tax	37,881	13,304	20,451
Total Taxes	761,786	448,564	596,367

OM&A COSTS TABLE

Expense Description	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
Operation									
5005-Operation Supervision and Engineering	25,564	54,587	29,023	56,710	2,123	70,525	13,815	72,325	1,800
5010-Load Dispatching	4,915	3,985	(930)	5,531	1,546	5,800	269	6,050	250
5012-Station Buildings and Fixtures Expense	31,323	38,576	7,253	37,632	(943)	38,450	818	40,400	1,950
5014-Transformer Station Equipment - Operation Labour	0	0	0	0	0	0	0	0	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0	0	0	0	0	0	0	0	0
5016-Distribution Station Equipment - Operation Labour	4,490	5,111	621	6,712	1,602	7,100	388	7,400	300
5017-Distribution Station Equipment - Operation Supplies and Expenses	2,115	1,360	(755)	1,703	343	1,850	147	2,000	150
5020-Overhead Distribution Lines and Feeders - Operation Labour	13,113	11,733	(1,380)	28,806	17,073	36,850	8,044	40,850	4,000
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	29,991	27,713	(2,278)	31,471	3,757	32,400	929	36,600	4,200
5030-Overhead Subtransmission Feeders - Operation	2,185	2,158	(27)	2,610	452	2,950	340	3,250	300
5035-Overhead Distribution Transformers- Operation	19,572	2,244	(17,328)	2,097	(147)	3,350	1,253	3,650	300
5040-Underground Distribution Lines and Feeders - Operation Labour	13,863	25,914	12,051	24,542	(1,371)	25,800	1,258	27,000	1,200
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	6,561	4,314	(2,247)	5,868	1,554	8,600	2,732	8,950	350
5050-Underground Subtransmission Feeders - Operation	0	0	0	0	0	0	0	0	0
5055-Underground Distribution Transformers - Operation	0	0	0	0	0	250	250	250	0
5060-Street Lighting and Signal System Expense	0	0	0	0	0	0	0	0	0
5065-Meter Expense	34,732	33,479	(1,253)	46,196	12,717	59,900	13,704	67,750	7,850
5070-Customer Premises - Operation Labour	46,752	60,633	13,881	42,833	(17,800)	45,000	2,167	47,200	2,200
5075-Customer Premises - Materials and Expenses	8,976	7,687	(1,289)	7,363	(324)	9,000	1,637	9,500	500
5085-Miscellaneous Distribution Expense	250,411	317,078	66,667	335,850	18,772	382,175	46,325	401,700	19,525
5090-Underground Distribution Lines and Feeders - Rental Paid	0	0	0	0	0	0	0	0	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	359	3,803	3,444	3,351	(452)	3,700	349	3,700	0
5096-Other Rent	0	0	0	0	0	0	0	0	0
Sub-Total	**494,922**	**600,374**	**105,452**	**639,277**	**38,902**	**733,700**	**94,423**	**778,575**	**44,875**
Maintenance									
5105-Maintenance Supervision and Engineering	19,387	11,127	(8,260)	9,824	(1,304)	11,100	1,276	11,950	850
5110-Maintenance of Buildings and Fixtures - Distribution Stations	0	0	0	0	0	0	0	0	0
5112-Maintenance of Transformer Station Equipment	0	0	0	0	0	0	0	0	0
5114-Maintenance of Distribution Station Equipment	38,467	36,652	(1,815)	36,343	(309)	35,100	(1,243)	39,300	4,200
5120-Maintenance of Poles, Towers and Fixtures	14,130	(2,229)	(16,359)	35,716	37,945	39,600	3,884	44,680	5,080
5125-Maintenance of Overhead Conductors and Devices	108,466	89,027	(19,439)	89,178	151	121,200	32,022	143,500	22,300
5130-Maintenance of Overhead Services	54,694	50,358	(4,336)	49,445	(912)	57,150	7,705	67,700	10,550
5135-Overhead Distribution Lines and Feeders - Right of Way	127,652	118,543	(9,109)	166,170	47,627	179,050	12,880	188,100	9,050
5145-Maintenance of Underground Conduit	0	0	0	0	0	0	0	0	0
5150-Maintenance of Underground Conductors and Devices	14,704	6,588	(8,116)	3,449	(3,139)	10,950	7,501	13,050	2,100
5155-Maintenance of Underground Services	30,446	47,563	17,117	39,169	(8,394)	53,850	14,681	64,550	10,700
5160-Maintenance of Line Transformers	34,119	30,037	(4,082)	31,786	1,749	42,100	10,314	50,250	8,150
5165-Maintenance of Street Lighting and Signal Systems	0	0	0	0	0	0	0	0	0
5170-Sentinel Lights - Labour	0	0	0	0	0	0	0	0	0
5172-Sentinel Lights - Materials and Expenses	0	0	0	0	0	0	0	0	0
5175-Maintenance of Meters	10,400	29,255	18,855	28,498	(757)	30,000	1,502	34,000	4,000
5178-Customer Installations Expenses- Leased Property	0	0	0	0	0	0	0	0	0
5185-Water Heater Rentals - Labour	0	0	0	0	0	0	0	0	0
5186-Water Heater Rentals - Materials and Expenses	0	0	0	0	0	0	0	0	0
5190-Water Heater Controls - Labour	0	0	0	0	0	0	0	0	0
5192-Water Heater Controls - Materials and Expenses	0	0	0	0	0	0	0	0	0
5195-Maintenance of Other Installations on Customer Premises	0	0	0	0	0	0	0	0	0
Sub-Total	**452,465**	**416,921**	**(35,544)**	**489,578**	**72,657**	**580,100**	**90,522**	**657,080**	**76,980**

Expense Description	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
Billing and Collections									
5305-Supervision	36,727	40,412	3,685	39,851	(561)	42,400	2,549	44,900	2,500
5310-Meter Reading Expense	141,809	145,366	3,557	145,829	463	142,800	(3,029)	153,200	10,400
5315-Customer Billing	327,243	338,215	10,972	350,047	11,832	367,100	17,053	383,950	16,850
5320-Collecting	268,481	281,076	12,595	311,898	30,823	322,000	10,102	345,200	23,200
5325-Collecting- Cash Over and Short	40	149	109	72	(77)	50	(22)	50	0
5330-Collection Charges	0	(32,558)	(32,558)	(37,069)	(4,512)	0	37,069	0	0
5335-Bad Debt Expense	27,516	28,353	837	64,729	36,376	29,000	(35,729)	30,000	1,000
5340-Miscellaneous Customer Accounts Expenses	6,968	28,580	21,612	47,819	19,239	47,600	(219)	53,300	5,700
Sub-Total	**808,784**	**829,594**	**20,810**	**923,175**	**93,581**	**950,950**	**27,775**	**1,010,600**	**59,650**
Community Relations									
5405-Supervision	0	0	0	0	0	0	0	0	0
5410-Community Relations - Sundry	4,601	6,767	2,166	9,350	2,583	8,500	(850)	8,100	(400)
5415-Energy Conservation	0	45,333	45,333	35,204	(10,129)	0	(35,204)	0	0
5420-Community Safety Program	395	0	(395)	2,815	2,815	0	(2,815)	1,000	1,000
5425-Miscellaneous Customer Service and Informational Expenses	3,294	8,113	4,819	2,521	(5,592)	2,100	(421)	2,600	500
5505-Supervision	0	0	0	0	0	0	0	0	0
5510-Demonstrating and Selling Expense	0	0	0	0	0	0	0	0	0
5515-Advertising Expense	0	0	0	0	0	0	0	0	0
5520-Miscellaneous Sales Expense	0	0	0	0	0	0	0	0	0
Sub-Total	**8,290**	**60,213**	**51,923**	**49,890**	**(10,323)**	**10,600**	**(39,290)**	**11,700**	**1,100**
Administrative and General Expenses									
5605-Executive Salaries and Expenses	348,799	334,839	(13,960)	108,380	(226,459)	197,050	88,670	214,350	17,300
5610-Management Salaries and Expenses	765	40,988	40,223	149,479	108,491	152,225	2,746	165,525	13,300
5615-General Administrative Salaries and Expenses	110,276	172,079	61,803	343,969	171,889	424,725	80,756	519,170	94,445
5620-Office Supplies and Expenses	61,822	63,479	1,657	67,198	3,719	71,750	4,552	82,450	10,700
5625-Administrative Expense Transferred Credit	0	0	0	0	0	0	0	0	0
5630-Outside Services Employed	105,987	86,849	(19,138)	57,371	(29,478)	54,500	(2,871)	56,800	2,300
5635-Property Insurance	15,724	15,058	(666)	40,670	25,612	42,500	1,830	44,200	1,700
5640-Injuries and Damages	32,404	24,135	(8,269)	32,834	8,699	39,000	6,166	40,600	1,600
5645-Employee Pensions and Benefits	17,075	(32,050)	(49,125)	0	32,050	0	0	9,400	9,400
5650-Franchise Requirements	0	0	0	0	0	0	0	0	0
5655-Regulatory Expenses	47,124	60,884	13,760	46,686	(14,198)	28,310	(18,376)	90,690	62,380
5660-General Advertising Expenses	2,551	0	(2,551)	0	0	0	0	0	0
5665-Misc General Expense	366,397	85,133	(281,264)	70,765	(14,368)	67,705	(3,060)	72,930	5,225
5670-Rent	1,106	323	(783)	323	0	330	7	350	20
5675-Maintenance of General Plant	103,574	129,342	25,768	142,926	13,584	144,580	1,654	150,600	6,020
5680-Electrical Safety Authority Fees	2,668	8,158	5,490	10,819	2,660	14,500	3,681	16,100	1,600
5685-Independent Market Operator Fees and Penalties	0	0	0	0	0	0	0	0	0
6205-Charitable Donations	0	0	0	0	0	0	0	0	0
Sub-Total	**1,216,272**	**989,218**	**(227,054)**	**1,071,420**	**82,202**	**1,237,175**	**165,755**	**1,463,165**	**225,990**
Taxes Other Than Income Taxes									
6105-Property Taxes	12,192	9,751	(2,441)	9,979	228	10,300	321	10,600	300
Sub-Total	**12,192**	**9,751**	**(2,441)**	**9,979**	**228**	**10,300**	**321**	**10,600**	**300**
Total OM&A before Amortization	**2,992,925**	**2,906,071**	**(86,854)**	**3,183,319**	**277,247**	**3,522,825**	**339,506**	**3,931,720**	**408,895**
Amortization Expenses									
5705-Amortization Expense - Property, Plant, and Equipment	1,454,453	1,548,934	94,481	1,664,804	115,869	1,775,255	110,451	1,980,834	205,579
Sub-Total	**1,454,453**	**1,548,934**	**94,481**	**1,664,804**	**115,869**	**1,775,255**	**110,451**	**1,980,834**	**205,579**
Total Operation, Maintenance & Admin costs	4,447,378	4,455,005	7,627	4,848,122	393,117	5,298,080	449,958	5,912,554	614,474
Variance - 1% of Total Distribution Exp before Taxes		44,550		48,481		52,981		59,126	

VARIANCE ANALYSIS ON OM&A COSTS:

Innisfil Hydro has provided a detailed OM&A cost table covering the periods from 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Bridge Year and 2009 Test Year including the variances year over year in Exhibit 4, Tab 2, Schedule 1. The variance that triggers the required analysis is $44,474, representing 1% of Innisfil Hydro's total distribution expenses before PILs based on Exhibit 4 Tab 1, Schedule 1, Table 1. The following table is a summary of OM & A expenses (excluding depreciation) analyzing the cost drivers from the 2006 EDR expenses to the 2009 Test Year expenses.

OM & A EXPENSES-VARIANCE ANALYSIS BY COST DRIVER 2006 EDR TO 2009

	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge Yr	2009 Test Yr	Increase from 2006 to 2009 $	%
Total OM & A Expenses	2,992,925	2,906,071	3,183,319	3,522,825	3,931,720		
OM & A Wages & Benefits	1,245,125	1,552,770	1,626,805	1,788,901	1,970,298	725,173	58.2%
OM & A non payroll expenses	1,747,800	1,353,301	1,556,514	1,733,924	1,961,422	213,622	12.2%
Total OM & A Expenses	2,992,925	2,906,071	3,183,319	3,522,825	3,931,720	938,795	31.4%

Analysis increased Wages & Benefits 2006 EDR to 2009	$	%
Staffing Changes		
Operations Supervisor	$ 102,443	8.2%
Engineering Tech vacancy	27,318	2.2%
General Accountant vacancy	28,411	2.3%
Customer Service-part time to full time position	26,523	2.1%
Accounting Student	10,000	0.8%
General Manager-part time to full time position	88,340	7.1%
Information Technologist	74,160	6.0%
Regulatory Analyst	81,250	6.5%
Overtime/On call cost	25,000	2.0%
Total Staffing changes	463,445	37.2%
Decrease in amounts charged to Intercompany	24,000	1.9%
Post retirement benefits	10,000	0.8%
Wages and Benefits Inflation	227,728	18.3%
Total increase of OM & A Wages and Benefits	$ 725,173	58.2%

Analysis increased non payroll expenses 2006 EDR to 2009	$	%
2006 EDR LV adjustment	-$ 314,000	-18.0%
Pole inspection	23,000	1.3%
Tree trimming	48,000	2.7%
Property and Liability Insurance	35,000	2.0%
GIS mapping	27,000	1.5%
Line Contractor change 2008 vs 2007	80,000	4.6%
Line Contractor change 2009 vs 2008	53,000	3.0%
Collection of account chg reclassification	37,000	2.1%
Regulatory expenses	37,000	2.1%
Total identified expense changes before inflation	26,000	1.5%
Inflation	187,622	10.7%
Total increase of OM & A non payroll expensess	$ 213,622	12.2%

MATERIALITY ANALYSIS ON OM&A COSTS:

Innisfil Hydro is providing the expense analysis by USofA accounts that contributed to the variance between the applicable years as submitted on the detailed OM & A table in Exhibit 4, Tab 2, Schedule 1.

2006 Board Approved vs. 2006 Actual:

	2006 EDR	2006 Actual	Variance
Total OM&A Expenses(excl depre)	$ 2,992,925	$ 2,906,071	-$ 86,854

Description	Account	Amount
New Hire-Operations Supervisor	5005 & 5085	$ 70,000
Vacancy-Engineering Technologist	5085	17,000
3rd Tranch CDM funds	5415	45,000
CSR from part time to full time	5340 & 5615	27,000
Vacancy-General Accountant	5605, 5610, 5615	28,000
Accounting Student	5615	10,000
IT Student	5610 & 5615	9,000
OMERS reallocation	5645	(49,000)
Regulatory costs	5655	25,000
LV charges included in 2006 EDR expenses	5665	(314,000)
Software annual maintence fees	5675	26,000

A. 5005 & 5085 – Supervisory & Miscellaneous Distribution Expenses total $96k variance increase:

- variance over 2006 board approved due to the hiring of the Operations Supervisor ($70k). This new position was created to manage the outside contracted line crews, management of SCADA system with backup and succession planning of the Director of Operations & Engineering, who is the main operator of the SCADA system
- 2006 EDR expenses included an Engineering Tech vacancy compared to 2006 actual ($17k)
- balance of the variance in two accounts is inflationary increases ($9k)

B. 5415 - Energy Conservation expense variance of $45k increase:

- variance over 2006 board approved due to the disbursement of 3rd tranche CDM funds for various CDM educational activities

C. 5340, 5605, 5610 & 5615 – Miscellaneous Customer Accounts and various Administrative Salaries & Expenses total $110k variance increase:

- variance over 2006 board approved due to the General Accountant position vacancy in 2006 EDR expenses compared to the position fully occupied in 2006 ($28k)
- a part time CSR was changed to a full time position in 2006 due to increasing demands of billing, collecting and settlements ($27k)
- 4 month year end Accounting student to assist with yearend in 2005 ($10k)

- 4 month IT student to assist with Innisfil Hydro's network, hardware, software and communication demands ($9k)
- balance of the variance in four accounts is two years of inflationary increases ($36k)

D. 5645 – Employee Pensions and Benefits variance of $49k increase:

- variance over 2006 Board Approved due to reallocation of employee OMERs costs to the regulatory account 1508 for the period of January to April 2006

E. 5655 – Regulatory Expense variance of $14k increase:

- variance over 2006 Board Approved due to reserve for intervener costs $25k
- 2006 actual OEB assessment cost are $11k lower than the 2006 EDR

F. 5665 – Misc General Expense variance of $281k decrease:

- variance over 2006 Board Approved due to Low Voltage Charges of $314k included in the 2006 Board Approved account. These charges were actually recorded to account 4750

G. 5675 – Maintenance of General Plant variance of $26k increase:

- variance over 2006 Board Approved due to increased billing software annual maintenance fees ($12k) due to upgrading of software modules, upgrading file imaging software ($4k) and software maintenance fees for new engineering software for job estimating and tracking ($7k).
- balance of the variance is the inflationary increase ($3k)

2007 Actual from 2006 Actual:

	2006 Actual	2007 Actual	Variance
Total OM&A Expenses(excl depre)	$ 2,906,071	$ 3,183,319	$ 277,247

Description	**Account**	**Amount**
Pole inspections	5120	$ 23,000
Account correction	5120	8,000
Tree Trimming	5135	48,000
Software maint, collection and training	5315 & 5320	15,000
Bad Debts	5335	36,000
Retiring employee	5005 & 5605	24,000
On call costs	5005 & 5605	11,000
Insurance	5635 & 5640	35,000
OMERS reallocation	5645	32,000
	Total	$ 232,000

A. 5120 – Maintenance of Poles, Towers and Fixtures variance of $38k increase:

- variance over 2006 Actual due to the contracting of pole inspections in 2007 ($23k)
- 2006 actual expense are in a credit balance due to capital costs that were recorded in 2005 were reallocated to the applicable capital account in 2006. ($8K)
- balance of the variance is the inflationary increase ($3k)

B. 5135 – Overhead Distribution Lines & Feeders variance of $48k increase:

-variance over 2006 Actual due to increased tree trimming costs. The tree trimming schedule was changed to cycle the tree trimming within the distribution territory every 3 years instead of 4 years due to the rural nature of the distribution territory to improve system reliability

C. 5315, 5320 & 5340 – Billing and Collecting Expense variance totalling $62k increase

- customer billing software maintenance in 2007 and not in 2006 ($4k)
- collection fees from collection agencies increased ($6K) due to ongoing collection effort
- increased customer service training for computer software and safety ($5k)
- cost reclassified from account 5615 in 2007 ($15k)
- job evaluations within the customer service area ($8k)
- balance due inflationary increases ($24k)

D. 5335 – Bad Debt Expense variance of $36k increase:

- the variance over 2006 Actual is due to the bankruptcy of a GS >50 kW customer ($16k) and a increase of bad debt reserve due to timing of outstanding customer accounts ($15k). The increase of outstanding accounts in the 181-365 days was a timing issue and reversed in Q1 2008.

E. 5005, 5305, 5330, 5605, 5610, 5615 – Executive, Management and General Admin Salaries total variance increase of $73k:

- Salaries between these 6 accounts were reallocated to better match the OEB APH definitions
-the variance over the 2006 Actual for these accounts is due to the reallocation of the Board of Directors stipends from account 5665 to 5605 ($30k)
- the retiring of the Director of Operations and the final payout of vacation and lieu time due ($24k)
- increase on call costs for the new Director of Operations ($11k)
- decrease of expenses over 2006 due to reclassification of customer service expenses to the billing and collecting expense classification ($15k)
- balance due to inflationary increases ($23k)

F. 5635 & 5640 – Property and Liability Insurance variance of $35k increase:

-variance over 2006 Actual due to updating the distribution station assets being valued and insured to 2006 replacement values and the addition of the Bob Deugo Station. Which was growth related

G. 5645 – Employee Pensions and Benefits variance of $32k increase:

-variance over 2006 Actual due to the OEB allowing the deferral of OMERs' employer costs in 2006 but not in 2007.

2008 Bridge from 2007 Actual:

	2007 Actual	2008 Bridge Year	Variance
Total OM&A Expenses(excl depre)	$ 3,183,319	$ 3,522,825	$ 339,506

Description	Account	Amount
Training and on call costs	5005 & 5085	10,000
GIS mapping	5085	$ 27,000
Line contractor change	5085,5125,5135,5150,5155,5160	74,000
Metering repairs and training	5065	11,000
Collection revenue reclass to acct 4235	5330	37,000
President; not performing town functions	5605	78,000
New Hire-IT	5615	64,000
G&A staff training & education	5615	5,000
	Total	$ 296,000

A. 5005 & 5085 – Miscellaneous Distribution Expense variance of $60k increase:

- additional training and on call costs for the Operations Management staff ($10K)
- variance over the 2007 Actual is due to upgrading the GIS mapping system ($27k). Innisfil Hydro will be integrating the GIS mapping with the Town of Innisfil and the increased costs are Innisfil Hydro portion of developing the GIS system. This will assist with locates and trouble calls in terms of response time and accuracy.
- additional variance over the 2007 Actual is due to the increase contracted line crew costs ($6k). Innisfil Hydro was informed in January 2007 the non union contractor that had been used for the past several years (McG) was being sold to K Line. In March 2007 a Tender for Overhead and Underground Hydro Utility Line works was requested by Innisfil Hydro for any interest contractors. The contract was awarded to K Line which had the lowest price increase. The cost overall of line crew work is expected to increase in excess of 20% in 2008 and 2009. This is reflected in the capital additions and the operations and maintenance costs
- balance due to inflationary increases ($17k)

B. 5065 – Metering Expense variance of $14k increase:

- additional costs for meter repairs ($6K)
- staff is attending a meter apprentice program ($5K)
- balance due to inflationary increases ($4k)

C. 5125, 5135, 5150, 5155, 5160 – Various Maintenance Expenses totalling a variance of $85k increase:

- variance over the 2007 Actual is due to the increase contracted line crew costs ($74k). Innisfil Hydro was informed in January 2007 the non union contractor that had been used for the past several years (McG) was being sold to K Line. In March 2007 a Tender for Overhead and Underground Hydro Utility Line works was requested by Innisfil Hydro for any interest contractors. The contract was awarded to K Line which had the lowest price increase. The cost overall of line crew work is expected to increase by 13% in 2008 and 16% in 2009. This is reflected in the capital additions and the operations and maintenance costs

- balance due to inflationary increases ($11k)

D. 5330 – Collection Charges variance of $37k increase:

- the variance over the 2007 Actual is due to the reclassification of the Collection of account charge to OEB APH account 4235 per Exhibit 3 Tab 3 Schedule 1.

E. 5605 – Executive Salaries and expenses variance of $89k increase:

- the variance over the 2007 Actual is due to a portion of the President's salary no longer being charged to the Town of Innisfil. Effective February 2008, the President no longer is carrying out the duties of the Director of Community Services for the Town of Innisfil. In the past, any time the President spent performing these duties was charged back to the Town fully burdened, and accounted for approximately 50% time or $78k. Due to the increasing demands of both of these positions, it was determined the Town would hire a full time position and the President would return to being a full time hydro employee effective February 2008.
- balance due to inflationary increases ($11k)

F. 5615 – General Administrative Salaries and Expenses variance of $81K increase:

-the variance over 2007 Actual is due to the addition of an Information Technologist headcount in February 2008 ($65k). The position was added to assist with the increasing demands of the SCADA, GIS, network security, hardware and software support

-saftety training and on going staff professional development costs ($5k)

- balance due to inflationary increases ($11k)

2009 Test Year from 2008 Bridge Year:

	2008 Bridge Year	2009 Test Year	Variance
Total OM&A Expenses(excl depre)	$ 3,522,825	$ 3,931,720	$ 408,895

Description	Account	Amount
Line contractor change	5020,5025,5085	10,000
Engineering job evaluation	5085	4,000
Meter reverifying	5065	5,000
Line contractor change	5114,5120,5125,5130,5135,5150,5155,5160	62,000
Metering reading	5310	10,000
CSR negotiated contract	5315,5320,5340	13,000
President; elimination of affiliate	5605	11,000
Management; elimination of affiliate	5610	12,000
Admin staff; elimination of affiliate	5610	6,000
New Hire-Regulatory analyst	5615	70,000
Communications upgrade	5620	7,000
Post retirement benefits	5645	9,000
Regulatory costs	5655	57,000
	Total	$ 276,000

A. 5020, 5025, 5085 – Various Operation Expense totalling a variance of $28k increase:

- variance over the 2008 Bridge Year is due to the increase contracted line crew costs ($10k). Innisfil Hydro was informed in January 2007 the non union contractor that had been used for the past several years (McG) was being sold to K Line. In March 2007 a Tender for Overhead and Underground Hydro Utility Line works was requested by Innisfil Hydro for any interest contractors. The contract was awarded to K Line which had the lowest price increase. The cost overall of line crew work is expected to increase by 13% in 2008 and 16% in 2008. This is reflected in the capital additions and the operations and maintenance costs
- job evaluations within the engineering area ($4k)
- balance due to inflationary increases ($14k)

B. 5065 – Meter Expense variance of $8k increase:

- the variance over the 2008 Bridge Year is due to the costs of reverification of meters ($5k) as required by Measurement Canada
- balance due to inflationary increases ($3k)

C. 5114, 5120, 5125, 5130, 5135, 5150, 5155, 5160 – Various Maintenance Expenses totalling a variance of $72k increase:

- variance over the 2008 Bridge Year is due to the increase contracted line crew costs ($62k). Innisfil Hydro was informed in January 2007 the non union contractor that had been used for the past several years (McG) was being sold to K Line. In March 2007 a Tender for Overhead and Underground Hydro Utility Line works was requested by Innisfil Hydro for any interested contractors. The contract was awarded to K Line which had the lowest price increase. The cost

overall of line crew work is expected to increase by 13% in 2008 and 16% in 2008. This is reflected in the capital additions and the operations and maintenance costs
- balance due to inflationary increases ($10k)

B. 5310 – Meter Reading Expense variance of $10k increase:
- the variance over the 2008 Bridge Year is due to the addition of a two wholesale meters and 6 retail interval meters ($7k)
- balance due to inflationary increases ($3k)

C. 5315, 5320 and 5340 – Customer Billing and Collecting Expense variance of $46k increase:
- the variance over the 2008 Bridge Year is due to the negotiated union wages contract ($10k)
- staff training for safety and software ($3k)
- balance due to inflationary increases ($33k)

D. 5605 – Executive Salaries and Expense variance of $17k increase:
- the variance over the 2008 Bridge Year is due to 11.5 months of the President's salary estimated to incurred ($8k)
- management time being spent on the distribution company's new technological activities opposed to the affiliate, Energy Services, ($4k)
- balance due to inflationary increases ($6k)

E. 5610 – Management Salaries and Expense variance of $13k increase:
- management time being spent on the distribution company's new technological activities opposed to the affiliate, Energy Services, and OPA programs ($9k). This is due to the planned sale of the water heaters from the affiliate and the ease of the new setup, design and reporting systems required by the OPA via the internet.
-balance due to inflationary increases ($4k)

F. 5615 – General Administrative Salaries & Expenses variance of $94k increase:
- the variance over the 2008 Bridge Year is due to the addition of a regulatory analyst to assist with the increasing demands and regulatory interpretations and requirements of the OEB reporting for projects such as rate filings, cost allocation, regulatory accounting, economic evaluations, the OEB quarterly and annual filings and distribution generation ($70k)
- staff time being spent on the distribution company's new technological activities opposed to the affiliate, Energy Services, ($6k)
-balance due to inflationary increases ($18k)

G. 5620 – Office Supplies and Expense variance of $11k increase:
- the variance over the 2008 Bridge Year is due to the cost of internet bandwidth upgrading ($7k)
- balance due to inflationary increases ($4k)

H. 5645 – Employee Pensions and Benefits Expense variance of $9k increase:

- the variance over the 2008 Bridge Year is due to post retirement benefits effective January 2009 ($9k). The estimated costs are based on an actuary's estimated benefit cost and annual benefit costs.

G. 5655 – Regulatory Expenses variance of $62k increase:

- the variance over the 2008 Bridge Year is due to a reversal of cost awards in 2008 ($20k). An estimate of the annual cost awards for $25k was made in 2006 based on the information available at the time. It has been determined the accrual is too high and is reversed in 2008
- also the 2009 test year includes a $37k expense for 1/4 of the costs of preparing the 2009 rate application.

SHARED SERVICES:

Introduction:

Innisfil Hydro currently provides management, customer service and accounts payable services to its affiliate Innisfil Energy Services Ltd it's water heater business. Innisfil Hydro operates under a Services Agreement that is updated on a yearly basis for the provision of any services performed for an affiliate. In order to remain in compliance with the OEB ARC, it was determined Innisfil Hydro could no longer provide customer service services. A tendering process for the sale of the water heaters will be implemented in 2008. It is estimated there will be no services provided to Innisfil Energy Services by Innisfil Hydro in 2009.

Summary of Intercompany Revenues:

A summary of Innisfil Hydro's 2006 Actual, 2007 Actual and projected 2008 and 2009 intercompany revenues is presented in following table:

Innisfil Hydro Intercompany Revenues
Table 1

Activity	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Management Services	31,555	26,328	27,727	-
Billing and Collecting Services	18,624	18,595	19,016	-
AP Services	1,217	1,363	1,358	-
Total	**51,396**	**46,286**	**48,101**	**-**

CORPORATE COST ALLOCATION:

N/A

PURCHASE OF SERVICES

Vdr Name	2007 Actual	2008 Bridge	2009 Test
AEGISYS	15,336	15,800	10,000
Network and IT security support			
Quotation			
Acumen Engineered Solutions	10,425	10,700	11,000
ESA Consulting			
Quotation			
Automated Solutions Inc	26,892	27,700	28,500
Engineering software maint fees & support			
Cost approach			
BDO Dunwoody	21,320	22,000	22,700
Annual accting software maintenance fee			
Cost approach			
Chec	13,942	14,145	14,300
Membership dues			
Cost approach			
DK Engineering Services	15,018	15,500	16,000
PHD engineering services			
Quotation			
Dave Dobinson Excavating	15,018	15,500	16,000
Yard maintenance and snow removal			
Tendering			
EDA	23,200	23,900	24,600
Membership dues			
Cost approach			
Euler Hermes	9,351	9,600	9,900
General Service bad debt insurance			
Quotation			
Grant Thorton	34,000	29,000	30,000
Audit fees			
Tendering approach			
Graham, Wilson and Green	7,037	7,500	8,000
Legal services			
Cost approach			
Harris Computer Systems	59,341	61,100	62,900
Annual software maintanence fee			
Cost approach			
K Line	-	200,600	393,200
Contracted line crew			
Tendering			
K-Teck Electro Services	25,158	25,900	26,700
Distribution Station maintenance			
Tendering			

Vdr Name	**2007 Actual**	**2008 Bridge**	**2009 Test**
Lakeside Tree Experts	107,392	110,600	113,900
Tree trimming			
Tendering			
The Lawn Baron	9,609	9,900	10,200
Property maintenance			
Tendering			
Loris Technologies	18,458	19,000	19,600
Annual software maintanence fees			
Cost approach			
Mc G Pole Line Ltd	240,856	124,000	-
Contracted line crew			
Tendering approach			
M E A R I E	82,664	85,100	87,700
Auto, property and liability Insurance			
Cost approach			
Mike Telus	10,129	10,400	10,700
In territory radio system			
Cost approach			
OEB	46,686	48,100	49,500
Regulator cost assessment			
Cost approach			
Olameter Inc	139,101	143,300	147,600
Meter reading services			
Quotation			
Oshawa PUC Services Inc	20,250	20,900	21,500
Wholesale and retail interval meter reads			
Cost approach			
Polecare International	20,250	20,900	21,500
Pole testing			
Quotation			
Savage Data Systems Ltd	50,133	51,600	53,100
Wholesale settlement data management			
Cost approach			
Solve Environmental	12,025	12,400	12,800
Office Cleaners			
Quotation			
Systrends Inc	30,571	31,500	32,400
EBT Hub Services			
Cost approach			
Annual Total	**1,064,161**	**1,166,645**	**1,254,300**

EMPLOYEE DESCRIPTION:

Innisfil Hydro's employee complement, compensation and benefits are set out in Table 1 below.

Table 1
Employee Information

Number of Employees (FTEs)	2006 EDR	2006	2007	2008	2009
Management	6.1	7.5	7.5	8.0	8.0
Union	13.9	16.3	16.6	17.3	18.3
Total	20	23.8	24.1	25.3	26.3
Number of Part Time Employees	2006 EDR	2006	2007	2008	2009
Management					
Union					
Total	0	0	0	0	0
Total Compensation	2006 EDR	2006	2007	2008	2009
Management	522,912	721,346	780,120	869,530	938,088
Union	787,213	920,584	965,448	1,050,971	1,179,210
Total	1,310,125	1,641,929	1,745,568	1,920,501	2,117,298
Compensation - Average Yearly Base Wages	2006 EDR	2006	2007	2008	2009
Management	71,436	75,080	80,630	84,218	90,994
Union	46,370	44,920	46,471	48,545	51,500
Compensation - Average Yearly Overtime	2006 EDR	2006	2007	2008	2009
Management	-	2,410	4,093	4,332	4,505
Union	825	376	122	121	118
Compensation - Average Yearly Incentive	2006 EDR	2006	2007	2008	2009
Management					
Union					
Compensation - Average Yearly Benefits	2006 EDR	2006	2007	2008	2009
Management	14,287	18,689	19,293	20,142	21,762
Union	9,439	11,181	11,567	12,084	12,819
	2006 EDR	2006	2007	2008	2009
Total Salary, Wages & Benefits Chged to O&M&A	1,245,125	1,552,770	1,626,805	1,788,901	1,970,298

OMERS Pension Expense and Post Retiree Benefits:

- **OMERS Pension**

All Innisfil Hydro employees are members of the Ontario Municipal Employees Retirement System ("OMERS"). Accordingly, Innisfil Hydro has provided the OMERS pension premium information for the 2007 Actual, 2008 Bridge Year and the 2009 Test Year in Table 2 below.

- **Post-Retirement Benefits - OMERS Members:**

Innisfil Hydro post-retirement benefits have been provided to its employees as of Jan 2009. Innisfil Hydro has provided post-retirement benefits accounting information as required in Table 3 below.

- **Post-retirement benefits accounting information:**

Innisfil Hydro pays 50% of the premiums of health, dental and life insurance benefits for early retirees from age 55 to 65 who have a minimum of 15 years of service with Innisfil Hydro.

- **Accounting treatment of post-retirement benefits:**

Employee future benefits are recorded on an accrual basis. The accrued benefit obligations and current service cost are calculated using the projected benefit method prorated on length of service and reflect management's best estimate of certain underlying assumptions by an actuary. The current service cost is for a period equal to the actuarial present value of benefits attributed to that period in which employees rendered their services. Significant assumptions underlying the valuation include management's best estimate of the interest (discount) rate, salary escalation, the average retirement age of employees, employee turnover and expected health and dental care costs.

The actuary has provided an estimate based on current information of a onetime setup charge of $23k and an estimated $2k annual costs for a total of $25K. Innisfil Hydro has only included 1/3 of the onetime charge for $7.5k plus and annual costs of $1.8k totalling $9.4k in account 5645 in this rate filing.

- **Treatment of changes in actuarial value in post-retirement benefits:**

The excess of actuarial gains (losses) over 10% of the accrued benefit obligation is amortized into expense on a straight-line basis over the expected average remaining service life of active employees.

Table 2
Pension Premium Information

Pension	2007 Actual	2008 Bridge Year	2009 Test Year
Pension premiums	98,261	113,001	124,423
Less: amount capitalized	6,780	7,571	8,585
Amount expensed	91,481	105,430	115,838

Table 3
Post-Retirement Benefit Information

Post Retirement Benefits	2007 Actual	2008 Bridge Year	2009 Test Year
Post-retirement Benefits Costs	0	0	22,604
Less: amount capitalized	0	0	0
Amount expensed	0	0	Onetime cost $22,604/3 + Est annual cost $1,797 = 9,400

DEPRECIATION, AMORTIZATION AND DEPLETION:

Innisfil Hydro confirms that it has complied with the APH with respect to the amortization of capital assets.

Amortization on capital assets is calculated as follows:

- Amortization calculated on a straight line basis over the estimated remaining useful life of the assets at the end of the previous year; plus:

- Amortization on capital additions during the current year – ½ rate of amortization commences in the year that the asset is capitalized.

In the Final Report of the Board on the 2006 EDRH, dated May 11, 2005, the OEB considered that the use of the average of the opening and closing balances for calculating amortization offered the most reliable figure without imposing an unreasonable burden on the distributor. In addition, the OEB noted (page 23) that the "object is to arrive at a data set that is more representative of a typical year in the life of the distributor".

Innisfil Hydro submits that its methodology for calculating amortization meets this objective.

Details of Innisfil Hydro's depreciation by asset group are provided in the Accumulated Depreciation Table at Exhibit 2, Tab 2, Schedule 4. Details of Innisfil Hydro's amortization and depletion by asset group are provided in the Fixed Asset Continuity Schedules at Exhibit 2, Tab 2, Schedule 1.

The following is a listing of Fixed Assets APH accounts, the associated estimated useful life and the related depreciation rates:

USAacct	AcctDesc	Useful Life	Depr %
1805	1805-Land	0	0
1806	1806-Land Rights	50	2
1808	1808-Buildings and Fixtures	-	-
1810	1810-Leasehold Improvements	25	4
1815	1815-Transformer Station Equip-Primary above 50 kV	-	-
1820	1820-Distribution Station Equip-Primary below 50 kV	25	4
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	5	20
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

DETERMINATION OF LOSS ADJUSTMENT FACTORS:

- **Total Loss Factor:**

Innisfil Hydro has calculated the Total Loss Factor as 1.0746 for secondary metered customers and 1.0638 for primary metered customers as calculated in Table 1 below.

- **Distribution Loss Factor:**

The Distribution Loss Factor (DLF) to be applied to customers' consumption is based on a three year average using the years 2005 to 2007. The recommended DLF for the 2009 test year is 1.0477 and 1.0372 for secondary and primary metered customers, respectively. The calculations are provided in Table 1 below.

Loss Factor Calculations
Table 1

	Description	2002	2003	2004	2005	2006	2007	Total (3 years)
A	"Wholesale" kWh IESO plus Embedded Generation	***221,214,597***	***225,570,526***	***225,463,256***	***234,717,280***	***227,671,082***	***235,121,981***	697,510,343
B	"Wholesale" kWh for Large Use customer(s)	0	0	0	0	0	0	0
C	Net "Wholesale" kWh (A)-(B)	221,214,597	225,570,526	225,463,256	234,717,280	227,671,082	235,121,981	697,510,343
D	"Retail" kWh (Distributor)	199,552,665	212,944,368	217,001,539	225,211,793	216,391,743	224,169,495	665,773,031
E	"Retail" kWh for Large Use Customer(s)	0	0	0	0	0	0	0
F	Net "Retail" kWh (D)-(E)	199,552,665	212,944,368	217,001,539	225,211,793	216,391,743	224,169,495	665,773,031
G	Loss Factor [(C)/(F)]	1.1086	1.0593	1.0390	1.0422	1.0521	1.0489	1.0477
H	Distribution Loss Adjustment Factor (3 year avg.)							**1.0477**
	Supply Facility Loss Factor	1.0395	1.0395	1.0397	1.0340	1.0296	**1.0257**	

Total Utility Loss Adjustment Factor		LAF
Supply Facility Loss Factor		1.0257
Distribution Loss Factor		
Distribution Loss Factor - Secondary Metered Customer < 5,000kW		1.0477
Distribution Loss Factor - Primary Metered Customer < 5,000kW		1.0372
Total Loss Factor		
Total Loss Factor - Secondary Metered Customer < 5,000kW		1.0746
Total Loss Factor - Primary Metered Customer < 5,000kW		1.0638

- **Supply Facility Loss Factor**

Table 2 provides the calculations of Innisfil Hydro's actual Supply Facility Loss Factor since 2002. Innisfil Hydro used the standard factor of 1.0045 in the 2006 EDR filing because of the information available at the time of filing. The 2002 to 2007 wholesale kWh data from the IESO has been analysed and Innisfil Hydro has determined the loss factor has been downward trending. Innisfil Hydro is therefore recommending the use of the 2007 SFLF value of 1.0257 for the 2009 Test Year.

Supply Facility Loss Factor

Table 2

Description	Full Year 2002	Full Year 2003	Full Year 2004	Full Year 2005	Full Year 2006	Full Year 2007	Total
"Wholesale" kWh IMO With Losses	**229,952,804**	**234,480,796**	**234,412,600**	**242,687,328**	**234,398,899**	**241,154,636**	1,417,087,063
"Wholesale" kWh IMO No Losses	*221,214,597*	*225,570,526*	*225,463,256*	*234,717,280*	*227,671,082*	*235,121,981*	1,369,758,722
Supply Facility Loss Factor	0.03950	0.03950	0.03969	0.03396	0.02955	0.02566	0.03455

- **Materiality Analysis on Distribution Losses:**

Innisfil Hydro's proposed distribution loss factor is 4.77% for 2009 and continues to strive to reduce line losses.

To try to maximize the reduction of line losses at Innisfil Hydro, several key items are considered to achieve the absolute efficiency of the distribution system. What can be one of the largest causes of line losses in a rural distribution setting is poorly maintained forestry programs that allow the growth of foliage into the primary voltage conductors. These trees will conduct electricity to a certain extent and depending on the amount of hydro load through the line, it can cause burring, smoking and eventual fire and outage. All of these factors contribute to the loss of electricity bleeding into the trees along the line. Innisfil Hydro has a strict mandate and corporate directive to trim and cut back all tree growth on a three year cycle as noted in Innisfil Hydro's Asset Management plan. Thus, leaving less chance of not only associated outages, but the reduction of line losses.

Another strategy that Innisfil hydro has undertaken to control line losses is the installation of additional capacitor banks to increase power factor at it's distribution stations throughout Innisfil. The introduction of capacitor banks, introduces load (KVARS) into a three phase circuit where fluctuating unbalanced load conditions exist. This in essence reduces line losses on primary circuits, that as an end result creates a more efficient power factor from the distribution transformer station.

Daily activities within the Innisfil Hydro Engineering and Operations department assures that whenever possible for capital and maintenance works, new design standards are followed to maximize on proper wire sizing and type. Having the proper wire size ensures good load flow through the conductors and is not restricted by resistance in the copper and aluminum wires. Another good utility practice Innisfil Hydro conducts is that it has its own engineered overhead and underground transformer specifications that are sent out to manufactures and constructed to the lowest possible loss factor to ensure optimal performance in the core of the transformer. Proper sizing of transformers are also looked at when considering installations or replacements so that a transformer is not oversized or undersized to mitigate on losses.

Conversion projects when and where possible are conducted by Innisfil Hydro to increase operating efficiency. Programs as recent as 2006 and 2007 and a possible project in 2009 have been done to convert from the 8320/4800 volt system to the more efficient 27600/16000 system. Although these conversions are not always possible to due geographical location, loading conditions and station back up redundancy, it remains a focal point to move toward.

Cooperation with local police authorities is also undertaken to find and stop thief of power diversions due to drug operations and other types of power thefts. Unmetered electricity adds to the losses reported by Innisfil Hydro and stopped at every possible opportunity. To date, many such operations have been stopped, the power diversion removed, and stolen usage collected from the party steeling it.

Reducing or eliminating line losses is a strategic goal at Innisfil Hydro. The benefits reach further than just financial implications, they also serve to make a more efficient, safe and reliable distribution of power to Innisfil Hydro's customers.

TAX CALCULATIONS:

Innisfil Hydro's detailed tax calculations are provided in the following table 1.

Table 1
Tax Calculations

Description	2006 Board Approved	2008 Bridge	2009 Test
Determination of Taxable Income			
Utility Income Before Taxes	881,942	950,250	1,470,445
Book to Tax Adjustments			
Additions to Accounting Income:			
Depreciation and amortization	1,454,453	1,775,255	1,980,834
Income or Loss for tax Purposes-joint ventures or partnerships	3,652	0	0
Interest and penalties on taxes	2,091	0	0
Meals & entertainment / Mileage	2,087	3,276	3,375
Non-deductible club fees and dues		0	0
Taxable Capital Gains	0	0	0
Tax reserves beginning of year	43,357	0	0
Reserves from financial statements -balance at year end	0	0	0
Pensions	55,856	0	0
Non-deductible contributions	359,401	0	0
Total Additions	**1,920,897**	**1,778,531**	**1,984,209**
Deductions from Accounting Income:			
Capital Cost Allowance	950,533	1,400,814	1,681,652
Gain on disposal of assets per financial statements	0	0	0
Cumulative eligible capital deduction	34,379	28,683	27,804
Tax reserves end of year	43,357	0	0
Excess Interest	47,665	0	0
Pensions	56,038	0	0
Deductible contributions	359,401	0	0
Total Deductions	**1,491,373**	**1,429,497**	**1,709,456**
Regulatory Taxable Income	**1,311,466**	**1,299,284**	**1,745,198**
Corporate Income Tax Rate	0	0	0
Subtotal	**473,701**		
Less: R&D ITC (0.3)	11,271		
Regulatory Income Tax	**462,430**	**435,260**	**575,915**
Calculation of Utility Income Taxes			
Income Taxes	462,430	435,260	575,915
Large Corporation Tax	0	0	0
Ontario Capital Tax	37,881	13,304	20,451
Total Taxes	**500,311**	**448,564**	**596,367**
Tax Rates			
Federal Tax	22.12%	19.50%	19.00%
Federal Surtax			
Provincial Tax	14.00%	14.00%	14.00%
Total Tax Rate	**36.12%**	**33.50%**	**33.00%**
Calculation of Large Corporation Tax			
Total Rate Base	22,626,868	20,912,835	24,089,366
Less: Exemption	50,000,000	50,000,000	50,000,000
Taxable Capital	**(27,373,132)**	**(29,087,165)**	**(25,910,634)**
LCT Rate	0.125%	0.125%	0.125%
Subtotal	(34,216)	(36,359)	(32,388)
Federal Surtax	0	0	0
Large Corporation Tax	**0**	**0**	**0**
Calculation of Ontario Capital Tax			
Total Rate Base	22,626,868	20,912,835	24,089,366
Less Exemption	10,000,000	15,000,000	15,000,000
Taxable Capital /Deemed taxable capital	**12,626,868**	**5,912,835**	**9,089,366**
OCT Rate	0.300%	0.225%	0.225%
Ontario Capital Tax	**37,881**	**13,304**	**20,451**

INTEREST EXPENSE

Innisfil Hydro has calculated the deemed interest expense in accordance with the Filing Requirements. Innisfil Hydro's deemed debt rate and deemed interest rate, and based on a 56.67/43.33 debt to equity ratio. Table 1 summarizes the interest calculations.

Table 1
Deemed Interest Expense

	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge Year	2009 Test Year
Long Term	900,561	901,105	915,397	892,761	795,169
Short Term					43,072
Total	900,561	901,105	915,397	892,761	838,240
Deemed debt rate-Long Term	9.19%	9.15%	9.11%	8.00%	6.27%
Deemed debt rate-Short Term	0.00%	0.00%	0.00%	0.00%	4.47%

CAPITAL COST ALLOWANCE:

Innisfil Hydro is providing Capital Cost Allowance continuity schedules for the 2008 Bridge Year and the 2009 Test Year on the following two pages.

2008 Bridge Year
Table 1

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	17,379,585	0	0	17,379,585	0	0	17,379,585	0	17,379,585	4%	695,183	16,684,402
2	Distribution System - pre 1988		0	0	0	0	0	0	0	0	6%	0	0
6	Buildings (No footings below ground)		0	0	0	0	0	0	0	0	10%	0	0
8	General Office/Stores Equip	444,858	0	0	444,858	34,100	0	478,958	17,050	461,908	20%	92,382	386,576
10	Computer Hardware/ Vehicles	126,096	0	0	126,096	38,000	0	164,096	19,000	145,096	30%	43,529	120,567
10.1	Certain Automobiles		0	0	0	0	0	0	0	0	30%	0	0
12	Computer Software	86,998	0	0	86,998	90,400	0	177,398	45,200	132,198	100%	132,198	45,200
13 1	Lease # 1		0	0	0	-	0	0	0	0	20%	0	0
13 2	Lease #2		0	0	0	0	0	0	0	0		0	0
13 3	Lease # 3		0	0	0	0	0	0	0	0		0	0
13 4	Lease # 4		0	0	0	0	0	0	0	0		0	0
14	Franchise		0	0	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs		0	0	0	0	0	0	0	0	8%	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment		0	0	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	61,107	0	0	61,107	0	0	61,107	0	61,107	45%	27,498	33,609
50	Computers & Systems Hardware acq'd post Mar 19/07	61,736	0	0	61,736	60,500	0	122,236	30,250	91,986	55%	50,592	71,644
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)		0	0	0	0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	2,890,872			2,890,872	3,204,060	0	6,094,932	1,602,030	4,492,902	8%	359,432	5,735,500
	SUB-TOTAL - UCC	**21,051,252**	**0**	**0**	**21,051,252**	**3,427,060**	**0**	**24,478,312**	**1,713,530**	**22,764,782**		**1,400,814**	**23,077,498**

CEC	Goodwill		0	0	0
CEC	Land Rights	398,131	0	0	398,131
CEC	FMV Bump-up		0	0	0
	SUB-TOTAL - CEC	**398,131**	**0**	**0**	**398,131**

Cumulative Eligible Capital Calculation

Cumulative Eligible Capital				398,131
Additions:				
Cost of Eligible Capital Property Acquired during the year	15500			
Other Adjustments	0			
Subtotal	15500	x 3/4 =	11625	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
			11625	409,756
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				409,756
Deductions:				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	409,756
Cumulative Eligible Capital Balance				409,756
CEC Deduction	7%	**Input the CEC deduction rate**		28,683
Cumulative Eligible Capital - Closing Balance				381,073

2009 Test Year

Table 2

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	**Distribution System - 1988 to 22-Feb-2005**	16,684,402	0	0	16,684,402	0	0	16,684,402	0	16,684,402	4%	667,376	16,017,026
2	**Distribution System - pre 1988**	0	0	0	0	0	0	0	0	0	6%	0	0
6	**Buildings (No footings below ground)**	0	0	0	0	0	0	0	0	0	10%	0	0
8	**General Office/Stores Equip**	386,576	0	0	386,576	36,200	0	422,776	18,100	404,676	20%	80,935	341,841
10	**Computer Hardware/ Vehicles**	120,567	0	0	120,567	76,000	0	196,567	38,000	158,567	30%	47,570	148,997
10.1	**Certain Automobiles**	0	0	0	0	0	0	0	0	0	30%	0	0
12	**Computer Software**	45,200	0	0	45,200	107,500	0	152,700	53,750	98,950	100%	98,950	53,750
13 1	**Lease # 1**	0	0	0	0	0	0	0	0	0	20%	0	0
13 2	**Lease #2**	0	0	0	0	0	0	0	0	0		0	0
13 3	**Lease # 3**	0	0	0	0	0	0	0	0	0		0	0
13 4	**Lease # 4**	0	0	0	0	0	0	0	0	0		0	0
14	**Franchise**	0	0	0	0	0	0	0	0	0		0	0
17	**New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs**	0	0	0	0	0	0	0	0	0	8%	0	0
43.1	**Certain Energy-Efficient Electrical Generating Equipment**	0	0	0	0	0	0	0	0	0	30%	0	0
45	**Computers & Systems Hardware acq'd post Mar 22/04**	33,609	0	0	33,609	0	0	33,609	0	33,609	45%	15,124	18,485
50	**Computers & Systems Hardware acq'd post Mar 19/07**	71,644	0	0	71,644	95,000	0	166,644	47,500	119,144	55%	65,529	101,115
46	**Data Network Infrastructure Equipment (acq'd post Mar 22/04)**	0	0	0	0	0	0	0	0	0	30%	0	0
47	**Distribution System - post 22-Feb-2005**	5,735,500			5,735,500	6,183,191	0	11,918,691	3,091,596	8,827,095	8%	706,168	11,212,523
	SUB-TOTAL - UCC	**23,077,498**	**0**	**0**	**23,077,498**	**6,497,891**	**0**	**29,575,389**	**3,248,946**	**26,326,443**		**1,681,652**	**27,893,736**

CEC	**Goodwill**	381,073	0	0	381,073
CEC	**Land Rights**	0	0	0	0
CEC	**FMV Bump-up**	0	0	0	0
	SUB-TOTAL - CEC	**381,073**	**0**	**0**	**381,073**

Cumulative Eligible Capital Calculation

Cumulative Eligible Capital				381,073
Additions:				
Cost of Eligible Capital Property Acquired during the year	21500			
Other Adjustments	0			
Subtotal	21500	x 3/4 =	16125	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
			16125	397,198
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				397,198
Deductions:				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	397,198
Cumulative Eligible Capital Balance				397,198
CEC Deduction	7%			27,804
Cumulative Eligible Capital - Closing Balance				369,394

Exhibit	Tab	Schedule	Appendix	Contents
5 – Deferral and Variance Accounts				
	1	1		Calculation of DVA Balances by Account
		2		Methods of Disposition of DVA Balances

CALCULATION OF DVA BALANCES BY ACCOUNT

Table 1

	1-Jan-2005 to 31-Dec-2005						1-Jan-2006 to 31-Dec-2006						1-Jan-2007 to 31-Dec-2007						Balance 31-Dec-2007			1-Jan-08 to 30-Apr-08		1-May-08 to 31-Dec-08		1-Jan-09 to 30-Apr-09	
Deferral / Variance Account	**Beg Bal**	**Chges**	**End Bal**	**Beg Int**	**Chges**	**End Int**	**Beg Bal**	**Chges**	**End Bal**	**Beg Int**	**Chges**	**End Int**	**Beg Bal**	**Chges**	**End Bal**	**Beg Int**	**Chges**	**End Int**	**Principal**	**Interest**	**Total**	**Interest**	**Balance**	**Interest**	**Balance**	**Interest**	**Balance**
1508-Other Regulatory Assets	44,717	110,288	155,005	256	2,725	2,981	155,005	-1,928	153,077	2,981	5,817	8,798	153,077		153,077	8,798	6,474	15,272	153,077	15,272	168,349	1,709	170,058	3,419	173,477	1,709	175,186
1550-LV Variance Account								67,718	67,718		732	732	67,718	162,256	229,974	732	6,826	7,558	229,974	7,558	237,532	2,568	240,100	5,136	245,236	2,568	247,804
TOTAL	**44,717**	**110,288**	**155,005**	**256**	**2,725**	**2,981**	**155,005**	**65,790**	**220,795**	**2,981**	**6,549**	**9,530**	**220,795**	**162,256**	**383,051**	**9,530**	**13,300**	**22,830**	**383,051**	**22,830**	**405,881**	**4,277**	**410,158**	**8,555**	**418,713**	**4,277**	**422,991**

METHODS OF DISPOSITION OF DVA BALANCES:

Innisfil Hydro is proposing to dispose of those Deferral Variance Accounts recommended for disposition by the OEB. The RSVA and RCVA accounts are therefore not included in the calculation of the proposed rate rider at this time and will be dealt with in a future proceeding. The methods proposed to dispose of the DVA balances, together with a summary of proposed rates and bill impacts, are set out in this Schedule.

1550 Low Voltage Variance Account

Disposal of December 31, 2007 balance plus interest to April 30, 2009 over a two-year period is requested.

Method of recovery: Allocation of costs in this account to rate classes on basis of transmission revenue.

1508 Other Regulatory Assets- Sub-account OMERS contributions

Disposal of December 31, 2007 balance plus interest to April 30, 2009 over a two-year period is requested.

Method of recovery: Allocation of costs in this account to rate classes on basis of kWh consumed.

1508 Other Regulatory Assets - Sub-account OEB Cost Assessments

Disposal of December 31, 2007 balance plus interest to April 30, 2009 over a two-year period is requested.

Method of recovery: Allocation of costs in this account to rate classes on basis of kWh consumed.

Proposed Rates ad Bill Impacts:

The total of the costs allocated to each customer class from the Method of Recovery discussed above is divided by either kW or kWh to arrive at the proposed customer class rate rider. The rate rider results and bill impacts that result from the disposal of the DVA balances, as requested, are set out in the table below.

PROPOSED RATES AND BILL IMPACTS
Table 1

RATE CLASS	PROPOSED RATE	BILL IMPACTS
Residential-1000 kWh	\$0.0010 / kWh	0.77%
GS<50 kW-4000 kWh	\$0.0008 / kWh	0.76%
GS>50 kW-30000 kWh 100 kW	\$0.2730 / kW	0.79%
Street Lighting-62 kWh .17 kW	\$0.2832 / kW	0.37%
Sentinel Lighting-135 kWh .30 kW	\$0.3517 / kW	0.46%
Unmetered Scattered Load-250 kWh	\$0.0011 / kWh	0.46%

OVERVIEW:

The purpose of this evidence is to summarize the method and cost of financing Innisfil Hydro's capital requirements for the 2009 test year.

Deemed Capital Structure:

Innisfil Hydro has a current a current deemed capital structure of 53.3% debt, 46.7%, and a return on equity of 9.00%, consistent with the capital structure and return specified in the OEB's Decision in EB-2007-0845, dated 21st April, 2008. Innisfil Hydro is requesting Board approval of a capital structure of 56.67% debt, 43.33% equity including an equity return of 8.57%.

Innisfil Hydro 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/40% equity ratio. Details are provided in Exhibit 6, Tab 1, Schedule 2. Innisfil Hydro believes the requested capital structure and equity return will provide continued access to long-term debt at reasonable rates.

Return on Equity:

Cost of Debt:

The details of Innisfil Hydro's forecast long-term debt cost of 6.27% for 2009 is provided in Exhibit 6 Tab 1, Schedule 3. Long-term debt cost information for the 2006 Board Approved, 2006 and 2007 Actual, 2008 Bridge Year are also provided in Exhibit 6, Tab 1, Schedule 3.

Return on Equity:

Innisfil Hydro 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 3. Innisfil Hydro understands that the OEB will be finalizing the return on equity for 2009 rates based on January 2009 market interest rate information. Innisfil Hydro'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.

DEEMED CAPITAL STRUCTURE

Table 1

2006 Board Approved

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	9,799,359	50.00%	9.19%	900,561.09
Unfunded Short Term Debt				
Total Debt	9,799,359	50.00%		900,561.09
Common Share Equity	9,799,359	50.00%	9.00%	881,942.31
Total equity	9,799,359	50.00%		881,942.31
Total Rate Base	19,598,718	100%	9.10%	1,782,503.40

2006

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	9,850,618	50.00%	9.15%	901,104.73
Unfunded Short Term Debt				
Total Debt	9,850,618	50.00%		901,104.73
Common Share Equity	9,850,618	50.00%	9.00%	886,555.64
Total equity	9,850,618	50.00%		886,555.64
Total Rate Base	19,701,236	100%	9.07%	1,787,660.37

2007

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	10,045,679	50.00%	9.11%	915,396.67
Unfunded Short Term Debt				
Total Debt	10,045,679	50.00%		915,396.67
Common Share Equity	10,045,679	50.00%	9.00%	904,111.11
Total equity	10,045,679	50.00%		904,111.11
Total Rate Base	20,091,358	100%	9.06%	1,819,507.78

2008 Bridge Year

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	11,152,815	53.33%	8.00%	892,761.09
Unfunded Short Term Debt				
Total Debt	11,152,815	53.33%		892,761.09
Common Share Equity	9,760,020	46.67%	9.00%	878,401.81
Total equity	9,760,020	46.67%		878,401.81
Total Rate Base	20,912,835	100%	8.47%	1,771,162.91

2009 Test Year

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	12,687,869	52.67%	6.27%	795,168.50
Unfunded Short Term Debt	963,575	4.00%	4.47%	43,071.79
Total Debt	13,651,444	56.67%		838,240.29
Common Share Equity	10,437,922	43.33%	8.57%	894,529.95
Total equity	10,437,922	43.33%		894,529.95
Total Rate Base	24,089,366	100%	7.19%	1,732,770.24

RETURN ON EQUITY

The calculations used to determine the ROE and the debt are determined in accordance with 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 Cost of Debt table provides the details of Innisfil Hydro's historical, current and projected debt requirements.

COST OF DEBT

Weighted Debt Cost

Description	Debt Holder	Affliated with LDC?	Date of Issuance	Principal	Term (Years)	Rate%	Year Applied to	Interest Cost
Note payable	Town of Innisf	Yes	December 31, 2003	2,107,444	4	7.25%	2006	152,790
				2,107,444		7.25%	2007	152,790
			December 31, 2007	2,107,444	2	3.35%	2008	70,599
				2,107,444		3.35%	2009	70,599
Debentures	Town of Innisf	No	April 1, 1995	6,640,000	20	9.75%	2006	647,400
				6,155,000		9.75%	2007	600,113
				5,621,000		9.75%	2008	548,048
				5,032,000		9.75%	2009	490,620
Bank Loan	Infastructure C	No	May 1, 2009	3,950,000	25	5.08%	2009	133,773
								0
								0
								0
								0
								0
								0
								0
								0
								0
								0
								0
								0
								0
								0

Total Long Term Debt Outstanding at end of 2006	8,747,444	**Total Interest Cost for 2006**	800,190
		Weighted Debt Cost Rate for 2006	9.15%
Total Long Term Debt Outstanding at end of 2007	8,262,444	**Total Interest Cost for 2007**	752,902
		Weighted Debt Cost Rate for 2007	9.11%
Total Long Term Debt Outstanding at end of 2008	7,728,444	**Total Interest Cost for 2008**	618,647
		Weighted Debt Cost Rate for 2008	8.00%
Total Long Term Debt Outstanding at end of 2009	11,089,444	**Total Interest Cost for 2009**	694,993
		Weighted Debt Cost Rate for 2009	6.27%

Debt Rate Calculations:

Innisfil Hydro's calculations of its debt rate for the years 2006 to 2009 are as follows:

	2006 Board Approved	2006	2007	2008 Bridge	2009 Test
Debt Service Costs	900,562	800,190	752,902	618,647	694,993
Average Debt Outstanding	9,586,444	8,747,444	8,262,444	7,728,444	11,089,444
Effective Debt Rate-LT -Short Term	**9.19%**	**9.15%**	**9.11%**	**8.00%**	**6.27% 4.47%**

2009 Return on Equity

	Deemed Portion	Effective Rate	Rate of Return
Cost of Capital-Long Term	56.67%	6.27%	3.30%
Cost of Capital-Short Term	4.00%	4.47%	0.18%
Equity	43.33%	8.57%	3.71%
Return on Equity			**7.19%**

REVENUE DEFICIENCY - OVERVIEW:

Innisfil Hydro projects that it will need to recover $ 8,241,691 in total revenue in the 2009 Test Year through distribution rates and other regulated charges. This includes:

$7,750,434 recovered through fixed and variable distribution rates (exluding Transformer allowance of $10,284 and LV charges of $497,129);

$491,257 recovered through Administration, Specific Service Charges and Other Miscellaneous Revenue.

At the existing distribution rates, Innisfil Hydro's 2009 Test Year gross revenue deficiency is calculated as $1,071,765 as shown on the following Calculation of Revenue efficiency.

Calculation of Revenue Deficiency

	2009 Test Existing Rates	2009 Test Proposed Rates
Revenue		
Suff/ Def From Below.		$1,071,765
Distribution Revenue	$6,678,669	$6,678,669
Other Operating Revenue (Net)	$491,257	$491,257
Total Revenue	$7,169,926	$8,241,691
Distribution Costs		
Operation, Maintenance, and Administration	$3,921,120	$3,921,120
Depreciation & Amortization	$1,980,834	$1,980,834
Property & Capital Taxes	$31,051	$31,051
Interest- Deemed Interest	$838,240	$838,240
Total Costs and Expenses	$6,771,245	$6,771,245
Utility Income Before Income Taxes	$398,681	$1,470,445
Net Adjustments per 2008 Pils	$274,753	$274,753
Taxable Income	$673,434	$1,745,198
Income Tax (Tax Rate 33.0%)	$222,233	$575,915
Utility Income	$176,448	$894,530
Rate Base	$24,089,366	$24,089,366
Equity	43.33%	43.33%
Equity Component Rate Base	$10,437,922	$10,437,922
Income / Equity Rate Base %	1.69%	8.57%
Target Return -Equity on Rate Base	8.57%	8.57%
Return- Equity on Rate Base	$894,530	$894,530
Revenue Deficiency	$718,082	
Revenue Deficiency (Gross-up)	$1,071,765	

COST ALLOCATION OVERVIEW:

<u>Introduction:</u>

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. Innisfil Hydro prepared a cost allocation information filing consistent with Innisfil Hydro's understanding of the Directions, the Guidelines, the Model and the Instructions. Innisfil Hydro submitted this filing to the OEB on January 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 Innisfil Hydro's cost data that supported its 2006 OEB-approved distribution rates. Consistent with the Guidelines, Innisfil Hydro 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 Innisfil Hydro on January 2007. In addition, the dollar amount by which each rate classification is being subsidized or over-contributing is provided. The calculations are based on Innisfil Hydro's OEB-approved 2006 electricity distribution rates.

Table 1
Revenue to Cost Ratios as Filed in Innisfil Hydro
Cost Allocation Informational Filing

Rate Classification	Revenue to Cost Ratio	$(Being Subsidized)/ $Over-Contributing
Residential	101.62%	$84,662
GS <50 kW	130.98%	$150,608
GS>50 kW	146.58%	$202,554
Street Lighting	9.45%	$(395,408)
Sentinel Lighting	16.97%	$(29,507)
Unmetered Scattered Load	78.89%	$(12,909)
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, Innisfil Hydro Cost Allocation Filing Results, only the Residential and GS >50kW are the customer classes currently falling within the revenue to cost ratio ranges established by the OEB. The table also provides the Proposed 2009 R/C 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 & Innisfil Hydro Results

Customer Class	OEB Low	OEB High	Innisfil Hydro Cost Allocation Filing Results	Innisfil Hydro Proposed 2009 Revenue to Cost Ratios
Residential	85%	115%	101.6%	101.2%
GS <50 kW	80%	120%	131.0%	116.2%
GS>50 kW	80%	180%	146.6%	135.8%
Street Lighting	70%	120%	9.5%	40.0%
Sentinel Lighting	70%	120%	17.0%	43.0%
Unmetered Scattered Load	80%	120%	78.9%	80.0%

Innisfil Hydro is proposing to re-align its revenue to cost ratios in this application by adjusting the allocations of revenue among its rate classes in order to reduce the cross-subsidization.

In Table 3, Column F, Innisfil Hydro provides the Proportions of 2009 Revenue that would result in customer class revenue to cost ratios (Column L) similar to those calculated by the Cost Allocation Filing (Column M), when compared to the revenue amounts calculated in Column E, which is an estimate of the 2009 revenue assuming a R/C ratios of 100%.

Table 3

Calculation of Revenue to Cost Ratios

Similar to Cost Allocation Informational Filing

	A	B	C	D	**E**	**F**	G	H	I	J	K	**L**	**M**
		Cust Class $ in A / Total $ of A	Cust Class Ratio in B * Total $ of C		**Colum C + Column D**		Column F * Total $ in Column G		Colum G + Column H		Colum G + Column H	**Column K / Column E**	
	2006 CA Rev Requirement Excl Trf All (Sheet O1 Rev Req less TA)	Proportion of Revenue	2009 Serv Rev Req Alloc	Add 2009 Trf All	**Assumed 100% R/C Ratio**	**Revenue Proportion to bring 2009 Revenues to Cot Allocation R/C results**	2009 Base Revenue Requirement	2009 Transformer Allowance	2009 Gross Distribution Revenue	2009 Proposed Misc Revenue	2009 Total Revenue Cost Allocation	**Calculated R/C Ratios**	**Cost Allocation Filing R/C Ratios**
Res	5,231,859	78.37%	6,458,734		**6,458,734**	**79.504%**	6,161,904		6,161,904	402,159	6,564,063	**101.6%**	**101.6%**
<50kW	486,106	7.28%	600,098		**600,098**	**9.541%**	739,487		739,487	46,606	786,092	**131.0%**	**131.0%**
>50kW	424,805	6.36%	524,422	10,284	**534,706**	**9.701%**	751,840	10,284	762,124	21,733	783,857	**146.6%**	**146.6%**
Street L	436,664	6.54%	539,062		**539,062**	**0.574%**	44,499		44,499	6,448	50,946	**9.5%**	**9.5%**
Sent L	35,538	0.53%	43,872		**43,872**	**0.086%**	6,628		6,628	818	7,446	**17.0%**	**17.0%**
USL	61,161	0.92%	75,503		**75,503**	**0.595%**	46,077		46,077	13,493	59,570	**78.9%**	**78.9%**
Total	6,676,133		8,241,691	10,284	**8,251,975**	**100.000%**	7,750,434	10,284	7,760,718	491,257	8,251,975		

Innisfil Hydro 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, Innisfil Hydro is proposing to move both of those classes half way to the lower revenue to cost band of 70% in this application and proposes to move to 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 the calculations showing a comparison of the 2009 Proposed Revenue to Cost rations in Column L, based on the Proposed 2009 Revenue Proportions in Column F, compared to the Revenue to Cost Ratios from the Cost Allocation Filing in column M. As noted earlier the R/C ratio for all customer classes are moving in the direction of a R/C ratio of 100%. For information purposes, the 2009 Proposed Miscellaneous Revenue in column J has been allocated to the customer classes on the same proportion as the Miscellaneous Revenue in the Cost Allocation Filing. The information in columns A to E in Table 4 is consistent with the information provided in column A to E in Table 3. The movement in revenue to cost ratios shown in column L compared to column M of Table 4 is a result of moving the proportion of revenues by rate class from the proportions shown in column G of Table 3 to the proportions shown in column G of Table 4.

Table 4

Calculation of 2009 Proposed Revenue to Cost Ratios

With Comparison to Cost Allocation Informational Filing Ratios

	A	B	C	D	E	**F**	G	H	I	J	K	**L**	**M**
		Cust Class $ in A / Total $ of A	Cust Class Ratio in B * Total $ of C		Colum C + Column D		Column F * Total $ in Column G		Colum G + Column H		Colum G + Column H	**Column K / Column E**	
	2006 CA Rev Requirement Excl Trf All (Sheet O1 Rev Req less TA)	Proportion of Revenue	2009 Serv Rev Req Alloc	Add 2009 Trf All	Assumed 100% R/C Ratio	**2009 Proposed Revenue Proportion**	2009 Base Revenue Requirement	2009 Transformer Allowance	2009 Gross Distribution Revenue	2009 Proposed Misc Revenue	2009 Total Revenue Cost Allocation	**2009 Proposed R/C Ratio**	**Cost Allocation Filing R/C Ratios**
Res	5,231,859	78.37%	6,458,734		6,458,734	**79.110%**	6,131,368		6,131,368	402,159	6,533,527	**101.2%**	**101.6%**
<50kW	486,106	7.28%	600,098		600,098	**8.395%**	650,633		650,633	46,606	697,238	**116.2%**	**131.0%**
>50kW	424,805	6.36%	524,422	10,284	534,706	**8.957%**	694,206	10,284	704,490	21,733	726,223	**135.8%**	**146.6%**
Street L	436,664	6.54%	539,062		539,062	**2.700%**	209,262		209,262	6,448	215,709	**40.0%**	**9.5%**
Sent L	35,538	0.53%	43,872		43,872	**0.233%**	18,059		18,059	818	18,877	**43.0%**	**17.0%**
USL	61,161	0.92%	75,503		75,503	**0.605%**	46,906		46,906	13,493	60,400	**80.0%**	**78.9%**
Total	6,676,133		8,241,691	10,284	8,251,975	**100.000%**	7,750,434	10,284	7,760,718	491,257	8,251,975		

Cost Allocation Summary:

The discussion and tables above support Innisfil Hydro'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. Innisfil Hydro 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 25% reallocation to the Street and Sentinel Lighting customer classes continue in 2010 and 2011 with proposed offsets to the GS<50 kW and GS>50 kW customer classes.

RATE DESIGN OVERVIEW:

This exhibit documents the calculation of Innisfil Hydro's proposed distribution rates by rate class for the 2009 test year, based on rate design as proposed in this Exhibit.

Innisfil Hydro has determined its total 2009 service revenue requirement to be $8,241,691. The total revenue offsets in the amount of $491,257 reduce Innisfil Hydro's total service revenue requirement to a base revenue requirement to $7,750,434, which is used to determine the proposed distribution rates. The base revenue requirement is derived from Innisfil Hydro's 2009 capital and operating forecasts, weather normalized usage, forecasted customer counts, and Innisfil Hydro's regulated return on rate base. The revenue requirement is summarized in the table below:

Calculation of Base Revenue Requirement

Table 1

OM&A Expenses	3,931,720
Amortization Expenses	1,980,834
Total Distribution Expenses	5,912,554
Regulated Return On Capital	1,732,770
PILs	596,367
Service Revenue Requirement	8,241,691
Less: Revenue Offsets	-491,257
Base Revenue Requirement	**7,750,434**

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.

Proposed Apportionment of Revenue to Rate Classes

Table 2

Rate Classification	Proposed Proportion of Revenue
Residential	79.110%
General Service Less Than 50 kW	8.395%
General Service Greater Than 50 kW	8.957%
Street Lights	2.700%
Sentinel Lights	0.233%
Unmetered Scattered Loads	0.605%
Total	100.0%

The following table outlines the results of this allocation.

Allocation of Outstanding Base Revenue Requirement

Table 3

Rate Classification	Proposed Revenue
Residential	$6,131,368
General Service Less Than 50 kW	$650,633
General Service Greater Than 50 kW	$694,206
Street Lights	$209,262
Sentinel Lights	$18,059
Unmetered Scattered Load	$46,906
Total	$7,750,434

Determination of Monthly Fixed Charges:

Innisfil Hydro's current OEB-approved monthly fixed charges based on its 2008 IRM application by customer class are summarized in the table below.

Current Monthly Fixed Charges

Table 4

Rate Class	Current Monthly Fixed Charge
Residential	$19.24
General Service Less Than 50 kW	$36.49
General Service Greater Than 50 kW	$359.80
Street Lights	$0.67
Sentinel Lights	$1.34
Unmetered Scattered Load	$18.25

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.

Table 5

Rate Class	Fixed Revenue Proportion	Variable Revenue Proportion
Residential	59.16%	40.84%
General Service Less Than 50 kW	52.18%	47.82%
General Service Greater Than 50kW	48.96%	51.04%
Street Lights	49.72%	50.28%
Sentinel Lights	57.59%	42.41%
Unmetered Scattered Load	75.76%	24.24%

Innisfil Hydro submits that it is appropriate for 2009 to shift the weighting of fixed vs. variable to increase the variable proportion to be aligned with the conservation movement.

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.

Innisfil Hydro confirms that it is proposing changes to the current fixed and variable proportions of its rates for the customer classes to go from a 57/43% fixed/variable mix to a 50/50% fixed/variable mix overall. The following Table provides Innisfil Hydro's calculations of its proposed monthly fixed distribution charges for the 2009 Test Year assuming the fixed/variable split supporting the current approved rates.

Proposed Fixed Distribution Charge

Table 6

Customer Class	Total Base Revenue Requirement	Fixed Revenue Proportion	2009 Test Year Customers	Proposed Fixed Distribution Charge
Residential	$6,131,368	50.88%	13,512	$19.24
General Service Less Than 50 kW	$650,633	51.86%	827	$34.00
General Service Greater Than 50 kW	$694,206	44.78%	72	$359.80
Street Lights	$209,262	48.34%	2,810	$3.00
Sentinel Lights	$18,059	57.71%	193	$4.50
Unmetered Scattered Loads	$46,906	50.54%	85	$23.24
Total	$7,750,434		17,499	

Proposed Volumetric Charges:

The variable distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate 2009 Test Year usage, kWh or kW, as the class charge determinant.

The following Table provides Innisfil Hydro'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 7

Customer Class	Total Base Revenue Requirement	Variable Revenue Proportion	Transformer Allowance	2009 Test Volumetric Billing Determinant		Proposed Volumetric Distribution Charge
Residential	$6,131,368	49.12%		153,846,698	kWh	$0.0196
General Service Less Than 50 kW	$650,633	48.14%		31,019,894	kWh	$0.0101
General Service Greater Than 50 kW	$694,206	55.22%	$10,284	115,534	kW	$3.4070
Street Lights	$209,262	51.66%		4,924	kW	$21.9540
Sentinel Lights	$18,059	42.29%		344	kW	$22.1992
Unmetered Scattered Loads	$46,906	49.46%		562,039	kWh	$0.0413
Total	$7,750,434					

Proposed Adjustment to Transformer Allowance:

Currently, Innisfil Hydro provides a Transformer Allowance to those customers that own their transformation facilities. Innisfil Hydro proposes to maintain the current approved transformer ownership allowance of $0.60 per kW. The Transformer Allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage level. Since the distributor provides electricity at utilization voltage, the cost of this transformation is captured in and recovered through the distribution rates. Therefore, when a customer provides its own step down transformation from primary to secondary, it should receive a credit of these costs already included in the distribution rates.

The amount of Transformer Allowance expected to be provided to those General Service Greater than 50 kW customers that own their transformers has been included in the General Service Greater Than 50 kW volumetric charge. This means the General Service Greater than 50 kW volumetric charge has been increased by $0.0890 per kW to $3.4070 per kW to recover the amount of the Transformer Allowance over all kWs in the General Service Greater Than 50 kW rate class. Once the Transformer Allowance is applied to this charge the resulting revenue will recover the full base revenue requirement for the General Service Greater than 50 kW rate class.

Recovery of Low Voltage Costs:

Consistent with the approach in the Board's 2006 EDR model, LV costs of $497,129 have been allocated to each rate class based on the proportion of retail transmission connection revenue collected from each class. This calculation is outlined in the following table:

Allocation of LV Costs

Table 8

Customer Class	Retail Transmission Connection Rate ($)		Basis for Allocation ($)	Allocation Percentages	Allocated $
	per KWh	per kW			
Residential	0.0100		1,538,466.98	67.26%	334,349.73
GS<50 (kW)	0.0091		282,281.04	12.34%	61,347.16
GS>50 (kW)		3.6636	423,270.36	18.50%	91,987.89
Street Lights		7.5898	37,372.18	1.63%	8,121.97
Sentinel Lights		2.8187	969.63	0.04%	210.73
Unmetered Scattered Loads	0.0091		5,114.55	0.22%	1,111.53
TOTALS			**2,287,474.74**	**100.00%**	**497,129.00**

These proposed LV costs by rate class are then divided by the projected volumes and this produces the proposed adjustments to the distribution volumetric charges set out in the table below:

LV-Related Adjustments to Volumetric Charges

Table 9

Customer Class	LV Adj. Allocated	Calculated kWh	Calculated kW	Volumetric Rate Type	LV/ Adj. Rates/kWh	LV Adj. Rates/ kW
Residential	334,349.73	153,846,698	0	kWh	0.0022	
GS<50 (kW)	61,347.16	31,019,894	0	kWh	0.0020	
GS>50 (kW)	91,987.89	39,978,179	115,534	kW		0.7962
Street Lights	8,121.97	1,652,371	4,924	kW		1.6495
Sentinel Lights	210.73	123,512	344	kW		0.6126
Unmetered Scattered Loads	1,111.53	562,039	0	kWh	0.0020	
TOTALS	**497,129.00**	**227,182,693**	**120,802**			

Proposed Distribution Rates:

The following table sets out Innisfil Hydo's proposed 2009 electricity distribution rates based on the foregoing calculations, including adjustments for the recovery of transformer allowance and the smart meter rate adder:

Proposed 2009 Electricity Distribution Rates including the LV adder

Table 10

Customer Class	Connection	Customer	kW	kWh
Residential	0.00	19.24	0.0000	0.0218
GS<50 (kW)	0.00	34.00	0.0000	0.0121
GS>50 (kW)	0.00	359.80	4.2032	0.0000
Street Lights	3.00	0.00	23.6035	0.0000
Sentinel Lights	4.50	0.00	22.8118	0.0000
Unmetered Scattered Loads	23.24	0.00	0.0000	0.0433

RATE MITIGATION:

Innisfil Hydro submits that the total bill impacts of its proposed 2009 electricity distribution rates for Residential, General Service<50 and General Service>50 are under 10% and therefore do not require rate mitigation.

The Street and Sentinel Lighting have total bill impacts over 10% due to the cost allocation within these classes determined with the Cost Allocation report that was filed to the OEB in early 2007. Innisfil Hydro has proposed to move these customer classes to the 70% Revenue to Cost ratio over the next 3 years as per Exhibit 8. As a result of very low current Revenue to Cost ratios it is expected these classes would experience higher increases than the other customer classes.

The total bill impact for the Unmetered Scattered Load class is over 10%. This is due to the move in the revenue to cost ratio to get that class into the band as required by the Cost Allocation report dated November 28, 2007 and the load used in the Cost Allocation study. With the pending rate design project, Innisfil Hydro is anticipating a requirement of having to provide an updated Cost Allocation submission. It should be noted Innisfil Hydro proposes to meter all customers in the USL customer class. It is expected most customers will be metered during the implementation of smart meters which is scheduled to take place by December 31, 2010.

RETAIL TRANSMISSION RATES

Although Hydro One has an application before the OEB for an increase in their Transmission Rates, Innisfil Hydro is proposing to maintain its existing Retail Transmission Network and Connection rates for its customer classes until notified by the Board to make a change.

The balances in Innisfil Hydro's related Deferral Variance Accounts are expected to be disposed of through a separate proceeding as indicated by the OEB.

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 single-phase.

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 Greater Than 50 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 greater than 50 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 the required lighting times established in the approved OEB street lighting load shape template.

EXISTING RATE SCHEDULE:

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	19.52
Distribution Volumetric Rate	$/kWh	0.0155
Retail Transmission Rate – Network Service Rate	$/kWh	0.0052
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0035
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	36.77
Distribution Volumetric Rate	$/kWh	0.0121
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0032
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Greater Than 50 kW

Service Charge	$	360.08
Distribution Volumetric Rate	$/kW	3.3571
Retail Transmission Rate – Network Service Rate	$/kW	1.9079
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2701
Retail Transmission Rate – Network Service Rate-Interval Metered	$/kW	1.8479
Retail Transmission Rate – Line and Transformation Connection Service Rate-Interval Metered	$/kW	1.8623
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 connection)	$	18.25
Distribution Volumetric Rate	$/kWh	0.0121
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0032
Wholesale Market Service Rate	/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	1.34
Distribution Volumetric Rate	$/kW	7.0109
Retail Transmission Rate – Network Service Rate	$/kW	1.4462
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0023
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)	$	0.67
Distribution Volumetric Rate	$/kW	5.0513
Retail Transmission Rate – Network Service Rate	$/kW	1.4389
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9818
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
Easement Letter	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special meter reads	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	15.00
Collection of account charge – no disconnection –after regular hours	$	165.00
Disconnect/Reconnect Charge - At Meter during Regular Hours	$	40.00
Disconnect/Reconnect Charge - 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	$	40.00
Install/Remove load control device – after regular hours	$	185.00
Temporary service – installs and remove – overhead – no transformer	$	500.00
Temporary service – installs and remove – underground – no transformer	$	300.00
Temporary service – install and remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Loss Factor

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.05939
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0434
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

PROPOSED RATE CLASSES

Innisfil Hydro is not requesting any changes to the existing rate classes.

Schedule of Proposed Tariff of Rates and Charges

Residential

Service Charge	$	19.52
Distribution Volumetric Rate	$/kWh	0.0218
Regulatory Asset Recovery	$/kWh	0.0010
Retail Transmission Rate – Network Service Rate	$/kWh	0.0052
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0035
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge	$	0.25

General Service Less Than 50 kW

Service Charge	$	34.28
Distribution Volumetric Rate	$/kWh	0.0121
Regulatory Asset Recovery	$/kWh	0.0008
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0032
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge	$	0.25

General Service Greater Than 50 kW

Service Charge	$	360.08
Distribution Volumetric Rate	$/kW	4.2032
Regulatory Asset Recovery	$/kW	0.2730
Retail Transmission Rate – Network Service Rate	$/kW	1.9079
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2701
Retail Transmission Rate – Network Service Rate-Interval Metered	$/kW	1.8479
Retail Transmission Rate – Line and Transformation Connection Service Rate-Interval Metered	$/kW	1.8623
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge	$	23.24
Distribution Volumetric Rate	$/kW	0.0433
Regulatory Asset Recovery	$/kW	0.0011
Retail Transmission Rate – Network Service Rate	$/kW	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.0032
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	3.00
Distribution Volumetric Rate	$/kW	23.6035
Regulatory Asset Recovery	$/kW	0.2832
Retail Transmission Rate – Network Service Rate	$/kW	1.4389
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9818
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per customer)	$	4.50
Distribution Volumetric Rate	$/kW h	22.8118
Regulatory Asset Recovery	$/kW h	0.3517
Retail Transmission Rate – Network Service Rate	$/kW	1.4462
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0023
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears certificate	$	15.00
Easement Letter	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special meter reads	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	15.00
Collection of account charge – no disconnection - after regular hours	$	165.00
Disconnect/Reconnect Charge - At Meter during Regular Hours	$	40.00
Disconnect/Reconnect Charge - 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	$	40.00
Install/Remove load control device – after regular hours	$	185.00
Temporary service – installs and remove – overhead – no transformer	$	500.00
Temporary service – installs and remove – underground – no transformer	$	300.00
Temporary service – install and 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)

Loss Factor

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0746
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0639
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

RECONCILIATION OF RATE CLASS REVENUE:
Table 1

Customer Class	Fixed Distribution Revenue	Variable Distribution Revenue	Transformer Allowance Credit	Total Distribution Revenue	Expected
Residential	$ 3,119,651	$ 3,353,858		$ 6,473,509	$ 6,465,718
GS<50 (kW)	$ 337,416	$ 375,341		$ 712,757	$ 711,980
GS>50 (kW)	$ 310,867	$ 485,613	($10,284)	$ 786,196	$ 786,194
Street Lights	$ 101,160	$ 116,224	$0	$ 217,384	$ 217,384
Sentinel Lights	$ 10,422	$ 7,847	$0	$ 18,269	$ 18,269
Unmetered Scattered Loads	$ 23,705	$ 24,336		$ 48,041	$ 48,018
Total	**$ 3,903,221**	**$ 4,363,218**	**($10,284)**	**$ 8,256,155**	**$ 8,247,563**

Difference Due to Rate Rounding

-$ 8,592

RATE AND BILL IMPACTS:

Appendix A to 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 and Smart Meter Rates.

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.

APPENDIX A

TABLE OF RATE AND BILL IMPACTS BY CUSTOMER CLASS

TABLE OF RATE AND BILL IMPACTS

RESIDENTIAL

Consumption: 100 kWh

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			19.24			19.24	0.00	0.00%	61.06%
Distribution (kWh)	100	0.0155	1.55	100	0.0218	2.18	0.63	40.65%	6.92%
Smart Meter Rider (per			0.28			0.28	0.00	0.00%	0.89%
LRAM & SSM Rider (kWh)	100			100	0.0000	0.00	0.00	0.00%	0.00%
Regulatory Assets (kWh)	100	0.0000	0.00	100	0.0010	0.10	0.10	100.00%	0.32%
Sub-Total			**21.07**			**21.80**	**0.73**	**3.46%**	**69.18%**
Other Charges (kWh)	105	0.0219	2.31	107	0.0219	2.35	0.05	1.97%	7.47%
Cost of Power Commodity	105	0.0545	5.74	107	0.0545	5.86	0.11	1.97%	18.59%
Total Bill Before Taxes			**29.12**			**30.01**	**0.89**	**3.05%**	**95.24%**
GST		5.00%	1.46		5.00%	1.50	0.04	3.05%	4.76%
Total Bill			**30.58**			**31.51**	**0.93**	**3.05%**	**100.00%**

RESIDENTIAL

Consumption: 250 kWh

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			19.24			19.24	0.00	0.00%	40.06%
Distribution (kWh)	250	0.0155	3.88	250	0.0218	5.45	1.58	40.65%	11.35%
Smart Meter Rider (per			0.28			0.28	0.00	0.00%	0.58%
LRAM & SSM Rider (kWh)	250			250	0.0000	0.00	0.00	0.00%	0.00%
Regulatory Assets (kWh)	250	0.0000	0.00	250	0.0010	0.25	0.25	100.00%	0.52%
Sub-Total			**23.40**			**25.22**	**1.83**	**7.80%**	**52.51%**
Other Charges (kWh)	263	0.0219	5.77	269	0.0219	5.88	0.11	1.97%	12.25%
Cost of Power Commodity	263	0.0545	14.36	269	0.0545	14.64	0.28	1.97%	30.48%
Total Bill Before Taxes			**43.52**			**45.75**	**2.22**	**5.10%**	**95.24%**
GST		5.00%	2.18		5.00%	2.29	0.11	5.10%	4.76%
Total Bill			**45.70**			**48.03**	**2.22**	**4.86%**	**100.00%**

RESIDENTIAL

Consumption **500 kWh**

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			19.24			19.24	0.00	0.00%	25.46%
Distribution (kWh)	500	0.0155	7.75	500	0.0218	10.90	3.15	40.65%	14.42%
Smart Meter Rider (per month)			0.28			0.28	0.00	0.00%	0.37%
LRAM & SSM Rider (kWh)	500			500	0.0000	0.00	0.00	0.00%	0.00%
Regulatory Assets (kWh)	500	0.0000	0.00	500	0.0010	0.50	0.50	100.00%	0.66%
Sub-Total			**27.27**			**30.92**	**3.65**	**13.38%**	**40.92%**
Other Charges (kWh)	527	0.0219	11.54	537	0.0219	11.77	0.23	1.97%	15.57%
Cost of Power Commodity (kWh)	527	0.0545	28.72	537	0.0545	29.28	0.56	1.97%	38.75%
Total Bill Before Taxes			**67.53**			**71.97**	**4.44**	**6.58%**	**95.24%**
GST		5.00%	3.38		5.00%	3.60	0.22	6.58%	4.76%
Total Bill			**70.91**			**75.57**	**4.66**	**6.58%**	**100.00%**

RESIDENTIAL

Consumption **600 kWh**

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			19.24			19.24	0.00	0.00%	22.90%
Distribution (kWh)	600	0.0155	9.30	600	0.0218	13.08	3.78	40.65%	15.57%
Smart Meter Rider (per month)			0.28			0.28	0.00	0.00%	0.33%
LRAM & SSM Rider (kWh)	600			600	0.0000	0.00	0.00	0.00%	0.00%
Regulatory Assets (kWh)	600	0.0000	0.00	600	0.0010	0.60	0.60	100.00%	0.71%
Sub-Total			**28.82**			**33.20**	**4.38**	**15.20%**	**39.51%**
Other Charges (kWh)	632	0.0219	13.85	645	0.0219	14.12	0.27	1.97%	16.81%
Cost of Power Commodity (kWh)	600	0.0545	32.70	600	0.0545	32.70	0.00	0.00%	38.92%
Total Bill Before Taxes			**75.37**			**80.02**	**4.65**	**6.17%**	**95.24%**
GST		5.00%	3.77		5.00%	4.00	0.23	6.17%	4.76%
Total Bill			**79.14**			**84.02**	**4.88**	**6.17%**	**100.00%**

RESIDENTIAL

Consumption
750 kWh

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			19.24			19.24	0.00	0.00%	18.66%
Distribution (kWh)	750	0.0155	11.63	750	0.0218	16.35	4.73	40.65%	15.86%
Smart Meter Rider (per			0.28			0.28	0.00	0.00%	0.27%
LRAM & SSM Rider (kWh)	750			750	0.0000	0.00	0.00	0.00%	0.00%
Regulatory Assets (kWh)	750	0.0000	0.00	750	0.0010	0.75	0.75	100.00%	0.73%
Sub-Total			**31.15**			**36.62**	**5.48**	**17.58%**	**35.52%**
Other Charges (kWh)	790	0.0219	17.31	806	0.0219	17.65	0.34	1.97%	17.12%
Cost of Power Commodity	600	0.0545	32.70	600	0.0545	32.70	0.00	0.00%	31.71%
Cost of Power Commodity	190	0.0545	10.38	206	0.0545	11.23	0.85	8.16%	10.89%
Total Bill Before Taxes			**91.53**			**98.20**	**6.66**	**7.28%**	**95.24%**
GST		5.00%	4.58		5.00%	4.91	0.33	7.28%	4.76%
Total Bill			**96.11**			**103.11**	**7.00**	**7.28%**	**100.00%**

RESIDENTIAL

Consumption
1,000 kWh

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			19.24			19.24	0.00	0.00%	14.73%
Distribution (kWh)	1,000	0.0155	15.50	1,000	0.0218	21.80	6.30	40.65%	16.69%
Smart Meter Rider (per			0.28			0.28	0.00	0.00%	0.21%
LRAM & SSM Rider (kWh)	1,000			1,000	0.0000	0.00	0.00	0.00%	0.00%
Regulatory Assets (kWh)	1,000	0.0000	0.00	1,000	0.0010	1.00	1.00	100.00%	0.77%
Sub-Total			**35.02**			**42.32**	**7.30**	**20.85%**	**32.39%**
Other Charges (kWh)	1,054	0.0219	23.08	1,075	0.0219	23.53	0.45	1.97%	18.01%
Cost of Power Commodity	600	0.0545	32.70	600	0.0545	32.70	0.00	0.00%	25.03%
Cost of Power Commodity	454	0.0545	24.74	475	0.0545	25.87	1.13	4.57%	19.80%
Total Bill Before Taxes			**115.54**			**124.42**	**8.88**	**7.69%**	**95.24%**
GST		5.00%	5.78		5.00%	6.22	0.44	7.69%	4.76%
Total Bill			**121.31**			**130.64**	**9.33**	**7.69%**	**100.00%**

RESIDENTIAL

Consumption
1,500 kWh

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			19.24			19.24	0.00	0.00%	10.36%
Distribution (kWh)	1,500	0.0155	23.25	1,500	0.0218	32.70	9.45	40.65%	17.61%
Smart Meter Rider (per			0.28			0.28	0.00	0.00%	0.15%
LRAM & SSM Rider (kWh)	1,500			1,500	0.0000	0.00	0.00	0.00%	0.00%
Regulatory Assets (kWh)	1,500	0.0000	0.00	1,500	0.0010	1.50	1.50	100.00%	0.81%
Sub-Total			**42.77**			**53.72**	**10.95**	**25.60%**	**28.93%**
Other Charges (kWh)	1,581	0.0219	34.62	1,612	0.0219	35.30	0.68	1.97%	19.01%
Cost of Power Commodity	600	0.0545	32.70	600	0.0545	32.70	0.00	0.00%	17.61%
Cost of Power Commodity	981	0.0545	53.46	1,012	0.0545	55.15	1.69	3.17%	29.70%
Total Bill Before Taxes			**163.55**			**176.87**	**13.33**	**8.15%**	**95.24%**
GST		5.00%	8.18		5.00%	8.84	0.67	8.15%	4.76%
Total Bill			**171.72**			**185.72**	**13.99**	**8.15%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
2,000 kWh

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			36.49			34.00	(2.49)	(6.82%)	14.55%
Distribution (kWh)	2,000	0.0121	24.20	2,000	0.0121	24.20	0.00	0.00%	10.36%
Smart Meter Rider (per			0.28			0.28	0.00	0.00%	0.12%
Regulatory Assets (kWh)	2,000	0.0000	0.00	2,000	0.0008	1.60	1.60	100.00%	0.68%
Sub-Total			**60.97**			**60.08**	**(0.89)**	**(1.46%)**	**25.71%**
Other Charges (kWh)	2,108	0.0211	44.47	2,149	0.0211	45.35	0.87	1.97%	19.41%
Cost of Power Commodity	750	0.0545	40.88	750	0.0545	40.88	0.00	0.00%	17.49%
Cost of Power Commodity	1,358	0.0545	74.00	1,399	0.0545	76.26	2.26	3.05%	32.63%
Total Bill Before Taxes			**220.32**			**222.56**	**2.24**	**1.02%**	**95.24%**
GST		5.00%	11.02		5.00%	11.13	0.11	1.02%	4.76%
Total Bill			**231.34**			**233.69**	**2.36**	**1.02%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
4,000 kWh

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			36.49			34.00	(2.49)	(6.82%)	7.88%
Distribution (kWh)	4,000	0.0121	48.40	4,000	0.0121	48.40	0.00	0.00%	11.22%
Smart Meter Rider (per			0.28			0.28	0.00	0.00%	0.06%
Regulatory Assets (kWh)	4,000	0.0000	0.00	4,000	0.0008	3.20	3.20	100.00%	0.74%
Sub-Total			**85.17**			**85.88**	**0.71**	**0.83%**	**19.91%**
Other Charges (kWh)	4,216	0.0211	88.95	4,299	0.0211	90.70	1.75	1.97%	21.02%
Cost of Power Commodity	750	0.0545	40.88	750	0.0545	40.88	0.00	0.00%	9.48%
Cost of Power Commodity	3,466	0.0545	188.88	3,549	0.0545	193.39	4.52	2.39%	44.83%
Total Bill Before Taxes			**403.87**			**410.85**	**6.98**	**1.73%**	**95.24%**
GST		5.00%	20.19		5.00%	20.54	0.35	1.73%	4.76%
Total Bill			**424.06**			**431.39**	**7.33**	**1.73%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
10,000 kWh

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			36.49			34.00	(2.49)	(6.82%)	3.32%
Distribution (kWh)	10,000	0.0121	121.00	10,000	0.0121	121.00	0.00	0.00%	11.81%
Smart Meter Rider (per			0.28			0.28	0.00	0.00%	0.03%
Regulatory Assets (kWh)	10,000	0.0000	0.00	10,000	0.0008	8.00	8.00	100.00%	0.78%
Sub-Total			**157.77**			**163.28**	**5.51**	**3.49%**	**15.94%**
Other Charges (kWh)	10,539	0.0211	222.37	10,746	0.0211	226.75	4.37	1.97%	22.13%
Cost of Power Commodity	750	0.0545	40.88	750	0.0545	40.88	0.00	0.00%	3.99%
Cost of Power Commodity	9,789	0.0545	533.50	9,996	0.0545	544.80	11.30	2.12%	53.18%
Total Bill Before Taxes			**954.52**			**975.70**	**21.18**	**2.22%**	**95.24%**
GST		5.00%	47.73		5.00%	48.78	1.06	2.22%	4.76%
Total Bill			**1,002.24**			**1,024.48**	**22.24**	**2.22%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
12,500 kWh

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			36.49			34.00	(2.49)	(6.82%)	2.67%
Distribution (kWh)	12,500	0.0121	151.25	12,500	0.0121	151.25	0.00	0.00%	11.89%
Smart Meter Rider (per			0.28			0.28	0.00	0.00%	0.02%
Regulatory Assets (kWh)	12,500	0.0000	0.00	12,500	0.0008	10.00	10.00	100.00%	0.79%
Sub-Total			**188.02**			**195.53**	**7.51**	**3.99%**	**15.38%**
Other Charges (kWh)	13,174	0.0211	277.97	13,433	0.0211	283.43	5.47	1.97%	22.29%
Cost of Power Commodity	750	0.0545	40.88	750	0.0545	40.88	0.00	0.00%	3.21%
Cost of Power Commodity	12,424	0.0545	677.09	12,683	0.0545	691.21	14.12	2.09%	54.36%
Total Bill Before Taxes			**1,183.96**			**1,211.05**	**27.10**	**2.29%**	**95.24%**
GST		5.00%	59.20		5.00%	60.55	1.35	2.29%	4.76%
Total Bill			**1,243.15**			**1,271.60**	**28.45**	**2.29%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
15,000 kWh

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			36.49			34.00	(2.49)	(6.82%)	2.24%
Distribution (kWh)	15,000	0.0121	181.50	15,000	0.0121	181.50	0.00	0.00%	11.95%
Smart Meter Rider (per			0.28			0.28	0.00	0.00%	0.02%
Regulatory Assets (kWh)	15,000	0.0000	0.00	15,000	0.0008	12.00	12.00	100.00%	0.79%
Sub-Total			**218.27**			**227.78**	**9.51**	**4.36%**	**15.00%**
Other Charges (kWh)	15,809	0.0211	333.56	16,119	0.0211	340.12	6.56	1.97%	22.40%
Cost of Power Commodity	750	0.0545	40.88	750	0.0545	40.88	0.00	0.00%	2.69%
Cost of Power Commodity	15,059	0.0545	820.69	15,369	0.0545	837.63	16.94	2.06%	55.15%
Total Bill Before Taxes			**1,413.39**			**1,446.41**	**33.01**	**2.34%**	**95.24%**
GST		5.00%	70.67		5.00%	72.32	1.65	2.34%	4.76%
Total Bill			**1,484.06**			**1,518.73**	**34.66**	**2.34%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
30,000 kWh	Monthly Service Charge			359.80			359.80	0.00	0.00%	10.41%
100 kW	Distribution (kWh)	30,000	0.0000	0.00	30,000	0.0000	0.00	0.00	0.00%	0.00%
	Distribution (kW)	100	3.3571	335.71	100	4.2032	420.32	84.61	25.20%	12.16%
	Smart Meter Rider (per month)			0.28			0.28	0.00	0.00%	0.01%
	Regulatory Assets (kW)	100	0.0000	0.00	100	0.2730	27.30	27.30	100.00%	0.79%
	Sub-Total			**695.79**			**807.70**	**111.91**	**16.08%**	**23.37%**
	Other Charges (kWh)	31,617	0.0132	417.34	32,239	0.0132	425.55	8.21	1.97%	12.31%
	Other Charges (kW)	105	3.1780	334.93	105	3.1780	334.93	0.00	0.00%	9.69%
	Cost of Power Commodity (kWh)	31,617	0.0545	1,723.13	31,617	0.0545	1,723.13	0.00	0.00%	49.86%
	Total Bill Before Taxes			**3,171.19**			**3,291.31**	**120.12**	**3.79%**	**95.24%**
	GST		5.00%	158.56		5.00%	164.57	6.01	3.79%	4.76%
	Total Bill			**3,329.75**			**3,455.87**	**126.12**	**3.79%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
75,000 kWh	Monthly Service Charge			359.80			359.80	0.00	0.00%	4.40%
250 kW	Distribution (kWh)	75,000	0.0000	0.00	75,000	0.0000	0.00	0.00	0.00%	0.00%
	Distribution (kW)	250	3.3571	839.28	250	4.2032	1,050.80	211.53	25.20%	12.85%
	Smart Meter Rider (per month)			0.28			0.28	0.00	0.00%	0.00%
	Regulatory Assets (kW)	250	0.0000	0.00	250	0.2730	68.25	68.25	100.00%	0.83%
	Sub-Total			**1,199.36**			**1,479.13**	**279.78**	**23.33%**	**18.08%**
	Other Charges (kWh)	79,043	0.0132	1,043.36	80,597	0.0132	1,063.88	20.52	1.97%	13.01%
	Other Charges (kW)	263	3.1780	837.32	269	3.1780	853.79	16.47	1.97%	10.44%
	Cost of Power Commodity (kWh)	79,043	0.0545	4,307.82	80,597	0.0545	4,392.53	84.72	1.97%	53.71%
	Total Bill Before Taxes			**7,387.86**			**7,789.33**	**401.48**	**5.43%**	**95.24%**
	GST		5.00%	369.39		5.00%	389.47	20.07	5.43%	4.76%
	Total Bill			**7,757.25**			**8,178.80**	**421.55**	**5.43%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption: 200,000 kWh, 500 kW

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			359.80			359.80	0.00	0.00%	1.82%
Distribution (kWh)	200,000	0.0000	0.00	200,000	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	500	3.3571	1,678.55	500	4.2032	2,101.60	423.05	25.20%	10.61%
Smart Meter Rider (per month)			0.28			0.28	0.00	0.00%	0.00%
Regulatory Assets (kW)	500	0.0000	0.00	500	0.2730	136.50	136.50	100.00%	0.69%
Sub-Total			**2,038.63**			**2,598.18**	**559.55**	**27.45%**	**13.12%**
Other Charges (kWh)	210,780	0.0132	2,782.30	214,925	0.0132	2,837.01	54.72	1.97%	14.33%
Other Charges (kW)	527	3.1780	1,674.65	537	3.1780	1,707.58	32.93	1.97%	8.62%
Cost of Power Commodity (kWh)	210,780	0.0545	11,487.51	214,925	0.0545	11,713.42	225.91	1.97%	59.16%
Total Bill Before Taxes			**17,983.08**			**18,856.20**	**873.11**	**4.86%**	**95.24%**
GST		5.00%	899.15		5.00%	942.81	43.66	4.86%	4.76%
Total Bill			**18,882.24**			**19,799.00**	**916.77**	**4.86%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption: 800,000 kWh, 2,000 kW

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			359.80			359.80	0.00	0.00%	0.46%
Distribution (kWh)	800,000	0.0000	0.00	800,000	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	2,000	3.3571	6,714.20	2,000	4.2032	8,406.40	1,692.20	25.20%	10.77%
Smart Meter Rider (per month)			0.28			0.28	0.00	0.00%	0.00%
Regulatory Assets (kW)	2,000	0.0000	0.00	2,000	0.2730	546.00	546.00	100.00%	0.70%
Sub-Total			**7,074.28**			**9,312.48**	**2,238.20**	**31.64%**	**11.93%**
Other Charges (kWh)	843,120	0.0132	11,129.18	859,701	0.0132	11,348.05	218.87	1.97%	14.54%
Other Charges (kW)	2,108	3.1780	6,698.59	2,149	3.1780	6,830.32	131.73	1.97%	8.75%
Cost of Power Commodity (kWh)	843,120	0.0545	45,950.04	859,701	0.0545	46,853.69	903.65	1.97%	60.02%
Total Bill Before Taxes			**70,852.09**			**74,344.54**	**3,492.45**	**4.93%**	**95.24%**
GST		5.00%	3,542.60		5.00%	3,717.23	174.62	4.93%	4.76%
Total Bill			**74,394.70**			**78,061.77**	**3,667.07**	**4.93%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
1,600,000 kWh
4,000 kW

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			359.80			359.80	0.00	0.00%	0.23%
Distribution (kWh)	1,600,000	0.0000	0.00	1,600,000	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	4,000	3.3571	13,428.40	4,000	4.2032	16,812.80	3,384.40	25.20%	10.97%
Smart Meter Rider (per			0.28			0.28	0.00	0.00%	0.00%
Transformer Credit	4,000	(0.6000)	(2,400.00)	4,000	(0.6000)	(2,400.00)	0.00	0.00%	(1.57%)
Regulatory Assets (kW)	4,000	0.0000	0.00	4,000	0.2730	1,092.00	1,092.00	100.00%	0.71%
Sub-Total			**11,388.48**			**15,864.88**	**4,476.40**	**39.31%**	**10.35%**
Other Charges (kWh)	1,686,240	0.0132	22,258.37	1,719,401	0.0132	22,696.10	437.73	1.97%	14.81%
Other Charges (kW)	4,216	3.1780	13,397.18	4,299	3.1780	13,660.64	263.47	1.97%	8.92%
Cost of Power Commodity	1,686,240	0.0545	91,900.08	1,719,401	0.0545	93,707.38	1,807.30	1.97%	61.16%
Total Bill Before Taxes			**138,944.10**			**145,929.00**	**6,984.90**	**5.03%**	**95.24%**
GST		5.00%	6,947.21		5.00%	7,296.45	349.24	5.03%	4.76%
Total Bill			**145,891.31**			**153,225.45**	**7,334.14**	**5.03%**	**100.00%**

Street Lighting

Billing Determinants
2,810 Connections
1,652,371 kWh
4,924 kW

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge	2,810	0.6700	1,882.70	2,810	3.0000	8,430.00	6,547.30	347.76%	3.08%
Distribution (kWh)	1,652,371	0.0000	0.00	1,652,371	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	4,924	5.0513	24,872.60	4,924	23.6035	116,223.63	91,351.03	367.28%	42.53%
Regulatory Assets (kW)	4,924	0.0000	0.00	4,924	0.2832	1,394.48	1,394.48	100.00%	0.51%
Sub-Total			**26,755.30**			**126,048.11**	**99,292.81**	**371.11%**	**46.12%**
Other Charges (kWh)	1,741,434	0.0211	36,744.25	1,775,681	0.0211	37,466.86	722.61	1.97%	13.71%
Other Charges (kW)	5,189	0.0000	0.00	5,291	0.0000	0.00	0.00	#DIV/0!	0.00%
Cost of Power Commodity	750	0.0545	40.88	750	0.0545	40.88	0.00	0.00%	0.01%
Cost of Power Commodity	1,740,684	0.0545	94,867.27	1,774,931	0.0545	96,733.72	1,866.45	1.97%	35.39%
Total Bill Before Taxes			**158,407.70**			**260,289.57**	**101,881.87**	**64.32%**	**95.24%**
GST		5.00%	7,920.38		5.00%	13,014.48	5,094.09	64.32%	4.76%
Total Bill			**166,328.08**			**273,304.05**	**106,975.97**	**64.32%**	**100.00%**

Street Lighting

Billing Determinants
1 Connections
62.47 kWh
0.17 kW

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge	1	0.6700	0.67	1	3.0000	3.00	2.33	347.76%	23.75%
Distribution (kWh)	62	0.0000	0.00	62	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	0.17	5.0513	0.84	0.17	23.6035	3.91	3.07	367.28%	30.93%
Regulatory Assets (kW)	0.17	0.0000	0.00	0.17	0.2832	0.05	0.05	100.00%	0.37%
Sub-Total			**1.51**			**6.95**	**5.45**	**361.71%**	**55.05%**
Other Charges (kWh)	66	0.0211	1.39	67	0.0211	1.42	0.03	1.97%	11.22%
Other Charges (kW)	0.17	0.0000	0.00	0.18	0.0000	0.00	0.00	#DIV/0!	0.00%
Cost of Power Commodity (kWh)	66	0.0545	3.59	67	0.0545	3.66	0.07	1.97%	28.97%
Total Bill Before Taxes			**6.48**			**12.03**	**5.54**	**85.53%**	**95.24%**
GST		5.00%	0.32		5.00%	0.60	0.28	85.53%	4.76%
Total Bill			**6.81**			**12.63**	**5.82**	**85.53%**	**100.00%**

Sentinel Lighting

Billing Determinants
193 Connections
123,512 kWh
344 kW

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge	193	1.3400	258.62	193	4.5000	868.50	609.88	235.82%	4.42%
Distribution (kWh)	123,512	0.0000	0.00	123,512	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	344	7.0109	2,411.75	344	22.8118	7,847.26	5,435.51	225.38%	39.91%
Regulatory Assets (kW)	344	0.0000	0.00	344	0.3517	120.98	120.98	100.00%	0.62%
Sub-Total			**2,670.37**			**8,836.74**	**6,166.37**	**230.92%**	**44.94%**
Other Charges (kWh)	130,169	0.0132	1,718.23	132,729	0.0132	1,752.03	33.79	1.97%	8.91%
Other Charges (kW)	363	2.4485	887.68	370	2.4485	905.14	17.46	1.97%	4.60%
Cost of Power Commodity (kWh)	130,169	0.0545	7,094.23	132,729	0.0545	7,233.74	139.51	1.97%	36.79%
Total Bill Before Taxes			**12,370.51**			**18,727.65**	**6,357.14**	**51.39%**	**95.24%**
GST		5.00%	618.53		5.00%	936.38	317.86	51.39%	4.76%
Total Bill			**12,989.04**			**19,664.03**	**6,674.99**	**51.39%**	**100.00%**

Sentinel Lighting

Billing Determinants		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
1 Connections	Monthly Service Charge	1	1.3400	1.34	1	4.5000	4.50	3.16	235.82%	19.46%
134.55 kWh	Distribution (kWh)	135	0.0000	0.00	135	0.0000	0.00	0.00	0.00%	0.00%
0.30 kW	Distribution (kW)	0.30	7.0109	2.10	0.30	22.8118	6.84	4.74	225.38%	29.59%
	Regulatory Assets (kW)	0.30	0.0000	0.00	0.30	0.3517	0.11	0.11	100.00%	0.46%
	Sub-Total			**3.44**			**11.45**	**8.01**	**232.51%**	**49.50%**
	Other Charges (kWh)	142	0.0132	1.87	145	0.0132	1.91	0.04	1.97%	8.25%
	Other Charges (kW)	0.32	2.4485	0.77	0.32	2.4485	0.79	0.02	1.97%	3.41%
	Cost of Power Commodity (kWh)	142	0.0545	7.73	145	0.0545	7.88	0.15	1.97%	34.07%
	Total Bill Before Taxes			**13.82**			**22.03**	**8.21**	**59.42%**	**95.24%**
	GST		5.00%	0.69		5.00%	1.10	0.41	59.42%	4.76%
	Total Bill			**14.51**			**23.13**	**8.62**	**59.42%**	**100.00%**

Unmetered Scattered

Consumption		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
250 kWh	Monthly Service Charge	1	18.2500	18.25	1	23.2400	23.24	4.99	27.34%	40.50%
	Distribution (kWh)	250	0.0121	3.03	250	0.0433	10.83	7.80	257.85%	18.86%
	Regulatory Assets (kW)	250	0.0000	0.00	250	0.0011	0.28	0.28	100.00%	0.48%
	Sub-Total			**21.28**			**34.34**	**13.07**	**61.41%**	**59.84%**
	Other Charges (kWh)	263	0.0211	5.56	269	0.0211	5.67	0.11	1.97%	9.88%
	Cost of Power Commodity (kWh)	263	0.0545	14.36	269	0.0545	14.64	0.28	1.97%	25.52%
	Total Bill Before Taxes			**41.19**			**54.65**	**13.46**	**32.67%**	**95.24%**
	GST		5.00%	2.06		5.00%	2.73	0.67	32.67%	4.76%
	Total Bill			**43.25**			**57.38**	**14.13**	**32.67%**	**100.00%**

Unmetered Scattered

Consumption
500 kWh

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge	1	18.2500	18.25	1	23.2400	23.24	4.99	27.34%	25.55%
Distribution (kWh)	500	0.0121	6.05	500	0.0433	21.65	15.60	257.85%	23.81%
Regulatory Assets (kW)	500	0.0000	0.00	500	0.0011	0.55	0.55	100.00%	0.60%
Sub-Total			**24.30**			**45.44**	**21.14**	**87.00%**	**49.97%**
Other Charges (kWh)	527	0.0211	11.12	537	0.0211	11.34	0.22	1.97%	12.47%
Cost of Power Commodity (kWh)	527	0.0545	28.72	537	0.0545	29.28	0.56	1.97%	32.20%
Total Bill Before Taxes			**64.14**			**86.61**	**22.47**	**35.04%**	**95.24%**
GST		5.00%	3.21		5.00%	4.33	1.12	35.04%	4.76%
Total Bill			**67.34**			**90.94**	**23.60**	**35.04%**	**100.00%**