INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED

APPLICATION FOR APPROVAL OF ELECTRICITY DISTRIBUTION RATES EFFECTIVE MAY 1, 2013

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

AND IN THE MATTER OF an Application by Innisfil Hydro Distribution Systems Limited to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2013.

Title of Proceeding:	An Application by Innisfil Hydro Distribution Systems Limited (IHDSL) for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2012.
Applicants Name:	Innisfil Hydro Distribution Systems Limited (IHDSL)
Applicants Address:	2073 Commerce Park Drive, Innisfil, ON L9S 4A2
Applicants Contacts:	Brenda L Pinke Regulatory/CDM Manager Direct Email: brendap@innisfilhydro.com Direct Line: 705-431-6870 Ext. 262 Direct Fax: 705-431-5901
	Laurie Ann Cooledge Chief Financial Officer/Treasurer Direct Email: lauriec@innisfilhydro.com Direct Line: 705-431-6870 Ext. 236 Direct Fax: 705-431-5901

EXECUTIVE OVERVIEW of IHDSL's APPLICATION

Executive Summary

IHDSL is a relatively young LDC, purchasing distribution assets from Ontario Hydro in 1993 to expand the service area to the boundaries of Innisfil. The distribution territory is relatively large at 292 square kilometres (the size of Mississauga) servicing the Town of Innisfil and south Barrie. Sub-transmission feeders travel 12km before entering the service territory.

The Province has deemed Innisfil and Barrie growth nodes with the following projections:

Area	Population 2012	Population 2031
Innisfil	32,000	56,000
South Barrie	500	39,000
Big Bay Point Development	0	1,600 units

Customer Increase of 140% is projected over the 20 year planning period.

To meet high growth requirements over the next 20 years, IHDSL has undertaken a thoroughly well planned and responsible COS rate application resulting in only the Sentinel Lighting rate class extending beyond the 10% threshold. The threshold limit increase for the Sentinel Lighting rate class was a direct result of the cost allocation ratios. IHDSL has contracted with the Town of Innisfil in 2012 to do their water and wastewater billing that will provide a positive return to customers.

The existing capital budget is being prudently managed and is not increasing except for the one-time requirement for a new office/operations facility.

IHDSL Hydro is currently utilizing two 'Panabode' wooden model homes for offices, a garage for warehouse space with the recent addition of two old school portables for additional space needs. The existing structures are not energy efficient, accessible or provide adequate space for growth requirements with the existing staff complement of 35 increasing to 75 by 2031. After receiving input from an external consultant on the cost of different options, a site was selected within the Town of Innisfil's administrative campus which has less expensive land, full utility servicing, is closer to Town centre for response purposes and has access to GO bus service. The cost of the new office/operations facility is budgeted at $7M and is designed to accommodate future growth. Some future space is intended to be leased out until required and is expected to provide a positive return to customers.

Long range growth planning occurs every four years with Hydro One and South Simcoe LDCs. The latest report published in January 2011 identifies the option for a transformer station in north Innisfil to meet future electricity demands. As a benefit of long range planning, IHDSL has seized the opportunity to acquire a 3 acre parcel of industrial land in Barrie, next to the Hydro One Right-of-way (ROW) with zoning that permits a transformer station. This is the last vacant industrial lot available in the area. Without long range planning, it is unlikely that vacant property with the required zoning would be available in the future. IHDSL is asking for recovery of this property that is required to service customers mandated by the Distribution System Code.

The depreciation expense has been reduced from the historic 25 year level to 45 years in many cases which means that a greater proportion of capital investments and economic evaluation contributions will be financed by debt. Maximum bank amortization limits remains at 25 years so even when assets get depreciated over 45 years, they are still paid for in 25 years. The long range financial forecast indicates that the 60% debt ceiling will be breached in 2013. IHDSL must borrow funds to pay for new development and will not get recovery for the interest on the debt above 60%. IHDSL's bank has confirmed that traditional debt/equity covenants of 75/25% are common for riskier enterprises than LDCs. IHDSL submits that the debt ceiling of 60% is

not sustainable for high growth LDCs like IHDSL and requests that the debt ceiling be raised to 75%.

The reduction in depreciation expense helps mitigate the P&L impact of resource requirements needed to maintain the following initiatives:

1. Low income payment plans and increased collection requirements.
2. International Financial Reporting System
3. Distributed Generation
4. Conservation Programs
5. Smart Meters and Smart Grid, and
6. Training for new hires to replace Staff who are retiring and for customer growth.

In an effort to substantiate the efficacy of this COS rate application and IHDSL's long range plan, public consultation was undertaken at the Innisfil Rotary Club and is scheduled for the Innisfil Chamber of Commerce in September. The following questions were asked of the participants and responses will be forthcoming in due course:

1. Is Innisfil Hydro's distribution rate impacts reasonable?
2. Is Innisfil Hydro's capital plan reasonable to meet growth requirements?
3. Is the new building plan reasonable?
4. Would it be reasonable for the four year rate application to be spread over four years to smooth out the rate impact?

IHDSL respectfully submits the following COS rate application to the Ontario Energy Board for approval. The application is being presented from the best information available at the time. Any changes to the assumptions during the application process will be forwarded to the OEB for consideration.

Introduction

The Applicant is Innisfil Distribution Systems Limited ("IHDSL"). The Applicant is a corporation incorporated pursuant to the Ontario Business Corporations Act with its head office in the Town of Innisfil, ON. The Applicant carries on the business of distributing electricity within the Town of Innisfil.

The Applicant hereby applies to the Ontario Energy Board (the "OEB") pursuant to Section 78 of the Ontario Energy Board Act, 1998 ("the OEB Act") for approval of its proposed distribution rates and other charges, effective May 1, 2013. A list of requested approvals is set out below.

Except where specifically identified in the Application, the Applicant followed the OEB's Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, update issued June 28, 2012 (the "Filing Requirements") in order to prepare this application.

Proposed Distribution Rates and Other Charges

The Schedule of Proposed Tariff of Rates and Charges in this Application is set out in Table 1.1 below and in Exhibit 8. The material being filed in support of this Application sets IHDSL's approach to its distribution rates and charges.

Proposed Effective Date of Rate Order

The Applicant requests that the OEB make its Rate Order effective May 1, 2013 in accordance with the Filing Requirements.

The Proposed Distribution Rates and Other Charges are Just and Reasonable

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

The proposed rates, as set out in Table 1.1, for the distribution of electricity have been prepared in accordance with the Filing Requirements and reflect traditional rate making and cost of service principles;

The proposed and adjusted rates are necessary to ensure IHDSL has sufficient funds to meet its capital expenditure obligations, fund OM&A expenses, provide for a reasonable Market Based Rate of Return ("MBRR") and Payments in Lieu of Taxes ("PILS");

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

The other specific service charges proposed by the Applicant are the same as those previously approved by the OEB; and

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

Relief Sought

The Applicant applies for an Order or Orders approving the proposed distribution rates and charges set out in Exhibit 8 to this Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2013.

The Applicant seeks approval of its Basic Green Energy Plan an request for a GEA Funding Adder as part of this Application in accordance with the Deemed Conditions of License as reported by the OEB in its Distribution System Planning Guidelines G-2009-0087, issued June 16, 2009. T he Applicants Basic Green Energy Plan has been prepared in accordance with the OEB's Filing Requirements as reported in EB-2009-0397 – Distribution System Plans under the Green Energy Act issued on December 18, 2009.

Form of Hearing Requested

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

DATED at Innisfil, Ontario, this 10th day of September, 2012.

All of which is respectfully submitted,

Innisfil Hydro Distribution Systems Limited

Original signed by

George Shaparew
President/CEO

ALIGNMENT OF RATE YEAR WITH FISCAL YEAR ANALYSIS

BACKGROUND

IHDSL is seeking approval for rates applied for in this application with an effective rate date of May 1, 2013.

However, in its letter dated April 15, 2010, the Ontario Energy Board (the "Board") advised distributors that it would hear the merits of aligning the rate year with the fiscal year for distributors on a case-by-case basis.

IHDSL agrees with this approach and is proposing the alignment be considered during this Cost of Service application, but having the implementation of the alignment take effect on January 1st of the following year as part of IHDSL's first IRM-based adjustment.

The Board requires all licensed electricity distributors to produce audited financial statements and a trial balance in the Uniform System of Accounts ("USofA") based on the calendar year. Thus, the fiscal year for electricity distributors is the calendar year.

The rate year for electricity distributors has evolved. Up until 2000, the rate year always commenced on January 1. In 2000, the Board released the Electricity Distribution Rate Handbook which changed the rate year to March 1. This remained until 2004, at which time the Board changed the rate year to April 1. For 2006, the Board released the 2006 Electricity Distribution Rate Handbook which changed the rate year to May 1, where it has remained for most distributors. Throughout this period of time, the fiscal year for distributors did not change. The changes for the rate year were generally based on administrative practices and to align distribution rate changes with commodity rate changes.

IHDSL is now proposing that its next rate year commence on January 1, 2014 to once again align with its fiscal year. This issue has been a concern for IHDSL for a number of years.

ISSUES TO BE ADDRESSED

Appendix B of the April 15, 2010 letter from the Board provided examples of the issues that should be addressed. Following is a discussion of those issues.

1. What are the benefits to the distributor of changing the rate year to match the fiscal year?

Aligning the rate year and the fiscal year will eliminate a number of issues for IHDSL. As noted by Enersource Hydro Mississauga ("Enersource") in proceeding EB-2009-0193, distributors must explain results to the investment community. This is true not only for "public issuers" such as Enersource but also distributors such as Innisfil Hydro who must report results to external bond holders, credit rating agencies, holders of credit facilities and the company's shareholder. The Enersource Decision stated:

"While the Board accepts Enersource's argument that aligning its rate year with its financial year would simplify reporting to the investment community and thus sees merit in the request, the Board believes that other distributors, particularly those that are reporting issuers, may also be interested in a change in rate year to January 1."

Explanations of financial results are complicated if the revenues are not aligned with the costs, particularly in a year with a cost of service rate application. This misalignment means that explanations must include a discussion about the impact of the stub periods from the previous rate year, and makes it more difficult to explain the company's financial performance in a transparent manner.

Furthermore, in filing a cost of service rate application, there are a number of added complexities if the costs are from January to December, but the associated revenues will not be collected until May through to April of the next year. Typically the final Board Decision for a May 1 rate change would not occur until April. This is more than a quarter of the way into the year in which the costs are to be incurred. If the Board denies costs in the rate

proceeding, there could be costs that the distributor has already incurred in the first four months of the year. If the distributor defers some spending (e.g. the hiring of new staff) until the Board's Decision, it may fall short of its planned spending for that year, not be able to complete all its planned work and have variances to explain.

There are also complexities to consider with respect to the calculation of Payments in Lieu of Taxes. Under the current rate year, the PILs allowance is collected from May of one year to April of the next year, for a tax year that is from January to December. Any "stub period" issues are ignored. This was identified in the 2006 Electricity Distribution Rate Handbook. These issues and complexities are all resolved if the rate year and the time period in which the costs will be incurred are the same.

One benefit to the Board of having some distributors seeking rates effective January 1, while others have May 1 effective rates, is that this will stagger the rate applications somewhat in any given year, and therefore spread out the workload at the Board.

2. What would be the implications of such a change from a ratepayers' perspective? For example, is it a concern that electricity consumers would see more frequent rate changes?

From IHDSL's perspective, having distribution rate changes at a different time from commodity rate changes will result in greater clarity and transparency for customers regarding distribution related rate adjustments versus rate changes due to other factors, including commodity rate changes that are established by the Board. This is a particularly relevant distinction for a municipally-owned distributor like IHDSL.

IHDSL agrees that the frequency of rate changes needs to be considered, but notes that it has been normal practice to have quarterly rate changes within the gas industry related to the Quarterly Rate Adjustment Mechanism ("QRAM"), and that the use of rate riders that start and stop at different times often results in rate changes throughout the year. Typically, with the proposed approach, distribution rates would change on January 1 and commodity rates

would change on May 1 and November 1. If there is a need to change any other regulated rates, this could occur at any of these three dates, perhaps providing more flexibility for a distributor to align its retail transmission rates with the wholesale transmission rate changes, which Hydro One Networks Inc. has recently applied to revise as of January 1, 2012.

2. *Under a Cost of Service mechanism, what are the specific issues from a ratemaking perspective of transitioning to a rate year that would be aligned with the fiscal year, and how should these issues be specifically addressed?*

The alignment of the rate year with the fiscal year as part of a cost of service application eliminates the issues that already exist, as discussed above, rather than creating new issues. Costs are reviewed by the Board for prudence as part of the proceeding and bill impacts considered in order to approve just and reasonable rates. Having those rates implemented over the same time period as the Board-approved costs does not create issues.

3. *What would be the specific issues relating to the timeliness of existing filing requirements such as bridge year information, audited financial statements, RRR reporting, tax returns, and review and disposition of deferral and variance account balances, and how should these be specifically addressed?*

By April 30 of each year, audited financials, the trial balance in the USofA and performance based regulation reporting have all been filed with the Board for the prior year. The information is generally available internally to staff within the distributor earlier for the purposes of preparing the rate application before the final results are approved and made public. Variance and deferral account balances are determined as part of the audited financials and therefore are available by April 30. Service quality indicators are filed by March 31. The tax return is available by no later than June 30, but again the specific information related to the return is available for internal use earlier to allow for preparation of the PILs allowance for the test year.

IHDSL recognizes that it may not be possible to include any actual information on the bridge year at the time of filing. However, it is typically part of the interrogatory process to update the bridge year data, which could include actual information to June 30.

5. Is there merit in considering the alignment during a Cost of Service application but having the implementation of the alignment take effect on January 1st of the following year as part of the distributor's first IRM-based adjustment?

IHDSL is in support of this proposal.

Fiscal and Rate Year Alignment

Improved Budget Planning

Alignment of the rate year and fiscal year will assist in future forecasting of rates and produce more consistent budget planning. The matching periods create a basis for more accurate forecasts. Considering rate forecasts are presented in a calendar year proposal, it makes sense to convert the rate year to the fiscal year. It allows for the presentation of data to be precise and consistent, including straight forward comparisons between the Test Year Rates and Historical Rates. The current Regulated Price Plan (RPP) generates a four month lag period between the fiscal year and rate year, in which adjustments must be made to appropriately calculate forecast rates. By aligning fiscal and rate year, the budget planning will be more accurate and simplified without having to make adjustments for forecasts.

Assistance in Financial Reporting

The existing rate year begins four months after the fiscal year start. This four month lag causes a lower actual return on equity (ROE) for LDCs than the Board approved ROE. Currently, two rates are used to calculate the actual ROE (four months with the old rate and eight months with the new rate), whereas the approved ROE is calculated with only one rate. Therefore, the actual ROE cannot be respectively compared to the approved ROE. The outcomes are inequities and inaccuracy in ROE from the present rate year lag.

The lag period causes difficulty in comparing the annual revenue requirement with actual costs. Costs are incurred in the first four months of the fiscal year, but revenues are not, prompting a mismatch in costs and revenues for the fiscal year. Complications in financial reporting are generated by the four month lag period.

If the rate year and fiscal year begin and end on the same dates, the revenues and costs of LDCs will be based on equivalent periods. Therefore, revenues are straight forward to report as changes in rate charges will occur within the fiscal year. Also, actual rate of return (ROR) for LDCs and the Board approved ROR will be based on the same period.

Presently, transmission rates are based on the fiscal year, while distribution rates have a 4 month lag period. Removal of this lag is important for timely rate schedules and the approved revenue requirement. Alignment of these rates will assist in billing and financial reporting as both rates will change simultaneously. Equivalent periods will simplify an LDC's financial reporting.

Alignment of the rate year with the fiscal year will simplify financial reporting specifically for the investment community. The current rate year lag complicates financial reports with discrepancies of financial analysis. To eliminate discrepancies in financial reporting, the alignment of the rate year with the fiscal year would mitigate this issue.

APPENDIX A

SCHEDULE OF PROPOSED RATES AND CHARGES

Innisfil Hydro Distribution Systems Ltd.

Proposed TARIFF OF RATES AND CHARGES for 2013

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

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to residential customers residing in detached, semi detached, townhouse (freehold or condominium) dwelling units duplexes or triplexes. Supply will be limited up to a maximum of 200 amp @ 240/120 volt. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge		$	24.04
Rate Rider for Disposition of Residual Historical Smart Meter Costs – effective until April 30, 2014		$	0.27
Rate Rider for Smart Meter –Stranded Meter – effective until April 30, 2015		$	0.83
Distribution Volumetric Rate		$/kWh	0.0214
Low Voltage Service Rate		$/kWh	0.0022
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014		$/kWh	(0.0032)
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until April 30, 2014		$/kWh	(0.0019)
Rate Rider for Global Adjustment Account Disposition (2012) - effective until April 30,2014 applicable only for Non-RPP Customers		$/kWh	(0.0002)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until April 30, 2014 applicable only for Non-RPP Customers		$/kWh	0.0062
GEA Rate Adder Rider– effective until April 30, 2016		$/kWh	0.5233
Retail Transmission Rate – Network Service Rate	$/kWh	0.0050	
Retail Transmission Rate – Line and Transformation Connection Service Rate		$/kWh	0.0040

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Innisfil Hydro Distribution Systems Ltd.
Proposed TARIFF OF RATES AND CHARGES for 2013

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

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly peak demand is less than or expected to be less than 50 kW. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge		$	33.84
Rate Rider for Disposition of Residual Historical Smart Meter Costs – effective until April 30, 2014		$	0.92
Rate Rider for Smart Meter – Stranded Meter – in effect until April 30. 2015		$	3.53
GEA Rate Adder Rider– effective until April 30, 2016	$ 0.5233		
Distribution Volumetric Rate		$/kWh	0.0083
Low Voltage Service Rate		$/kWh	0.0021
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014		$/kWh	(0.0026)
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until April 30, 2014		$/kWh	(0.0019)
Rate Rider for Global Adjustment Account Disposition (2012) - effective until April 30,2014 applicable only for Non-RPP Customers		$/kWh	(0.0002)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until April 30, 2014 applicable only for Non-RPP Customers		$/kWh	0.0062
Retail Transmission Rate – Network Service Rate		$/kWh	0.0046
Retail Transmission Rate – Line and Transformation Connection Service Rate		$/kWh	0.0037

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Innisfil Hydro Distribution Systems Ltd.
Proposed TARIFF OF RATES AND CHARGES 2013

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

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is expected to be equal to or greater than 50 kW but less than 5000 kW. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	246.68
Distribution Volumetric Rate	$/kW	2.3152
Low Voltage Service Rate	$/kW	0.7580
GEA Rate Adder Rider– effective until April 30, 2016	$	0.5233
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kW	(0.7860)
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until April 30, 2014	$/kW	(0.6695)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014 applicable only for Non-RPP Customers	$/kW	(0.0632)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until April 30, 2014 applicable only for Non-RPP customers	$/kW	2.1298
Retail Transmission Rate – Network Service Rate	$/kW	1.8708
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4516
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	1.8119
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.1284

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Innisfil Hydro Distribution Systems Ltd.
Proposed TARIFF OF RATES AND CHARGES

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

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 240/120 or 120 volts whose monthly peak demand is less than or expected to be less than 50 kW and the consumption is unmetered. A detailed calculation of the load will be calculated for billing purposes. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	10.35
Distribution Volumetric Rate	$/kWh	0.0174
Low Voltage Service Rate	$/kWh	0.0021
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kWh	(0.0036)
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until April 30, 2014	$/kWh	(0.0019)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until April 30, 2014 applicable only for Non-RPP customers	$/kWh	(0.0002)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until April 30, 2014 Applicable only for Non-RPP customers	$k/Wh	0.0062
Retail Transmission Rate – Network Service Rate	$/kWh	0.0046
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0037

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Innisfil Hydro Distribution Systems Ltd.

Proposed TARIFF OF RATES AND CHARGES 2013

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

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	9.08
Distribution Volumetric Rate	$/kW	41.3339
Low Voltage Service Rate	$/kW	0.5859
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kW	(1.3065)
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until April 30, 2014	$/kW	(0.6946)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until April 30, 2014 applicable only for Non-RPP Customers	$/kW	2.2100
Rate Rider for Global Adjustment Sub-Account Disposition (2012) –effective until April 30, 2014 applicable only for Non-RPP customers	$/kW	(0.0656)
Retail Transmission Rate – Network Service Rate	$/kW	1.4180
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6635

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Innisfil Hydro Distribution Systems Ltd.
Proposed TARIFF OF RATES AND CHARGES 2013

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

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts concerning roadway lighting for a Municipality, Regional Municipality, and/or the Ministry of Transportation. This lighting will be controlled by photocells. The consumption for these customers will be based on the calculated connected load times as established in the approved OEB Street Lighting Load Shape Template. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	6.48
Distribution Volumetric Rate	$/kW	44.8755
Low Voltage Service Rate	$/kW	0.8687
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kW	(0.9549)
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until April 30, 2014	$/kW	(0.6492)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014 applicable only for Non-RPP customers	$/kW	(0.0613)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until April 30, 2014 applicable only for Non-RPP Customers	$/kW	2.0655
Retail Transmission Rate – Network Service Rate	$/kW	1.4109
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1220

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Innisfil Hydro Distribution Systems Ltd.

Proposed TARIFF OF RATES AND CHARGES

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

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

Innisfil Hydro Distribution Systems Ltd.

Proposed TARIFF OF RATES AND CHARGES

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

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)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration		
Arrears Certificate	$	15.00
Easement Letter	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned Cheque (plus bank charges)	$	15.00
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 at meter – during regular hours	$	40.00
Disconnect/Reconnect at Meter - after regular hours	$	185.00
Disconnect/Reconnect at Pole – during regular hours	$	185.00
Disconnect/Reconnect at Pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	40.00
Install/Remove load control device – after regular hours	$	185.00
Temporary service install and remove – overhead – no transformer	$	500.00
Temporary service install and remove – underground – no transformer	$	300.00
Temporary service install and remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Innisfil Hydro Distribution Systems Ltd.

Proposed TARIFF OF RATES AND CHARGES

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

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

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

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

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0766
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0659

DISTRIBUTOR LICENCE:

A copy of Innisfil Hydro's Electricity Distribution Licence ED-2002-0520, issued on November 6, 2003, and amended on November 12, 2010, accompanies this application as Appendix 1.

APPENDIX 1

DISTRIBUTOR LICENSE

Ontario

Electricity Distribution Licence

ED-2002-0520

Innisfil Hydro Distribution Systems Ltd.

Valid Until

November 5, 2023

Kirsten Walli
Board Secretary
Ontario Energy Board
Date of Issuance: November 6, 2003
Date of Amendment: November 12, 2010

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

Commission de l'énergie de l'Ontario
C.P. 2319
2300, rue Yonge
27e étage
Toronto ON M4P 1E4

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1 Definitions

In this Licence:

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

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

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

"**Conservation and Demand Management**" and "**CDM**" means distribution activities and programs to reduce electricity consumption and peak provincial electricity demand;

"**Conservation and Demand Management Code for Electricity Distributors**" means the code approved by the Board which, among other things, establishes the rules and obligations surrounding Board approved programs to help distributors meet their CDM Targets;

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

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

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

"**Licensee**" means Innisfil Hydro Distribution Systems Ltd.

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

"**Net Annual Peak Demand Energy Savings Target**" means the reduction in a distributor's peak electricity demand persisting at the end of the four-year period (i.e. December 31, 2014) that coincides with the provincial peak electricity demand that is associated with the implementation of CDM Programs;

"**Net Cumulative Energy Savings Target**" means the total amount of reduction in electricity consumption associated with the implementation of CDM Programs between 2011-2014;

"**OPA**" means the Ontario Power Authority;

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

"**Provincial Brand**" means any mark or logo that the Province has used or is using, created or to be created by or on behalf of the Province, and which will be identified to the Board by the Ministry as a provincial mark or logo for its conservation programs;

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

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

"**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;

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

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

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

2 Interpretation

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

3 Authorization

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

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

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

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

4 Obligation to Comply with Legislation, Regulations and Market Rules

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

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

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

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

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

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

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

6 Obligation to Provide Non-discriminatory Access

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

7 Obligation to Connect

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

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

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

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

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

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

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

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

8 Obligation to Sell Electricity

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

9 Obligation to Maintain System Integrity

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

10 Market Power Mitigation Rebates

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

11 Distribution Rates

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

12 Separation of Business Activities

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

13 Expansion of Distribution System

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

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

14 Provision of Information to the Board

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

14.2 Without limiting the generality of paragraph 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.

15 Restrictions on Provision of Information

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

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

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

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

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

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

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

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

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

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

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

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

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

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

17 Term of Licence

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

18 Fees and Assessments

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

19 Communication

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

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

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

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

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

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

20 Copies of the Licence

20.1 The Licensee shall:

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

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

21 Conservation and Demand Management

21.1 The Licensee shall achieve reductions in electricity consumption and reductions in peak provincial electricity demand through the delivery of CDM programs. The Licensee shall meet its 2014 Net Annual Peak Demand Savings Target of 2.500 MW, and its 2011-2014 Net Cumulative Energy Savings Target of 9.200 GWh (collectively the "CDM Targets"), over a four-year period beginning January 1, 2011.

21.2 The Licensee shall meet its CDM Targets through:

a) the delivery of Board approved CDM Programs delivered in the Licensee's service area ("Board-Approved CDM Programs");

b) the delivery of CDM Programs that are made available by the OPA to distributors in the Licensee's service area under contract with the OPA ("OPA-Contracted Province-Wide CDM Programs"); or

c) a combination of a) and b).

21.3 The Licensee shall make its best efforts to deliver a mix of CDM Programs to all consumer types in the Licensee's service area.

21.4 The Licensee shall comply with the rules mandated by the Board's Conservation and Demand Management Code for Electricity Distributors.

21.5 The Licensee shall utilize the common Provincial brand, once available, with all Board-Approved CDM Programs, OPA-Contracted Province-Wide Programs, and in conjunction with or co-branded with the Licensee's own brand or marks.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

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

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

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

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.

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

SCHEDULE 3 LIST OF CODE EXEMPTIONS

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

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

APPENDIX A

MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

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

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

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

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

2. Information Given to IESO

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

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

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

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

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

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity

consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

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

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

3. Pass Through of Rebate

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

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

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

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

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

"ONTARIO POWER GENERATION INC. rebate"

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

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

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

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

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

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

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

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

2. Information Given to IESO

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

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

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

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

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

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

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO 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.

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b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 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

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

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

CONTACT INFORMATION:

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Facsimile 416 361-2751
Email jsidlofsky@blgcanada.com

SPECIFIC APPROVALS REQUESTED:

In this proceeding, IHDSL is requesting the following approvals:

- Approval to charge rates effective May 1, 2013 to recover a revenue requirement of $9,419,635 which includes a revenue deficiency of $761,836 as set out in Exhibit 6, Schedule 1, Tab 1; the schedule of proposed rates is set out in Exhibit 8 Tab 6 Schedule 4;

- Approval of the proposed loss factor as set out in Exhibit 8, Tab 4, Schedule 1;

- Approval of revised low voltage rates to be included in the standard distribution rates as proposed and described in Exhibit 8, Tab 2, Schedule 1;

- Approval to charge a Retail Transmission Network Service rate and a Retail Transmission Connection Rate as proposed and described in Exhibit 8, Tab 3, Schedule 1;

- Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the OEB Decision and Order in the matter of IHDSL's 2012 Distribution Rates (EB-2011-0176/EB-2011-0435);

- Approval to continue the Specific Service Charges and Transformer Allowance approved in the OEB Decision and Order in the matter of IHDSL's 2012 Distribution Rates (EB-2011-0176//EB-2011-0435);

- Approval to dispose of the Deferral and Variance Account balances as at December 31 2011, over a one year period using the method of recovery described in Exhibit 9, Tab 1, Schedule 2:

- Approval of the proposed Global Adjustment rider as reflected on IHDSL's proposed Tariff sheet and calculated in Exhibit 9

- Approval for a stranded meter rate rider of $0.83 per month per metered residential customer and $3.53 per month per metered General Service <50kW customer, for two years to recover the net book value of $359, 195 for stranded meters as at December 31, 2012.

- Approval of IHDSL's Green Energy Plan and requested GEA Funding Adder for the purpose of renewable capital investment based on the calculation and methodology described in Exhibit 2, Tab 6 and Exhibit 9 Tab 4;

- Approval for the creation of a PP&E deferral account to record the difference in 2012 Net Book Value of Property, Plant and Equipment, as a result of the transition from financial reporting under Canadian Generally Accepted Accounting Principles (CGAAP) to reporting under Modified International Financial Reporting Standards (MIFRS), and the disposition of this account using the method of recovery described in Exhibit 9, Tab7;

- Approval to continue with #1508 - Other Regulatory Assets - sub-account – Deferred IFRS Transition Costs and sub-account – Incremental Capital Charges to track costs, revenues and interest for amounts to be disposed of in a future rate proceeding.

- As directed, IHDSL has recorded in account 1592 the incremental Input Tax Credit (ITC) it receives on distribution revenue requirement items that were previously subject to PST and become subject to HST. IHDSL has complied with this directive and has been recording these amounts as of July 1, 2011. The application IHDSL is currently submitting is based on budgeted information net of any HST ITCs IHDSL will receive. As a result, IHDSL requests approval to discontinue recording these variances as of May 1, 2013.

- Approval of IHDSL's request to the realignment of the rate year to the fiscal year with the implementation of the alignment to take effect on January 1st of the following year of our COS application as part of IHDSL's first IRM-based adjustment.

- In the event the OEB is unable to provide a Decision and Order on the Application before May 15, 2013 for implementation of rates by IHDSL as of May 1, 2013, IHDSL requests the OEB issue an Interim Order approving the proposed distribution rates and other charges, effective May 1, 2013 which may be subject to adjustment based on its final Decision and Order.

- IHDSL will publish the notice for the Cost of Service application in the Innisfil Examiner, which is a paid publication, published weekly, with an average circulation of 12,500.

PROPOSED ISSUES LIST:

Innisfil Hydro would expect, based on previous regulatory experience and other hearings, that the following matters pertaining to the 2013 Test Year may constitute issues in this Application:

- The reasonableness of IHDSL's proposed capital program, including a one-time capital expenditure for IHDSL's Head Office and Operations Centre.
- The reasonableness of IHDSL's proposed OM&A expenses including additional FTE requests.
- The reasonableness and appropriateness of IHDSL's 2013 Load Forecast
- The reasonableness of IHDSL's Revenue Deficiency

PROCEDURAL ORDERS/MOTIONS/NOTICES:

On January 26, 2012 the Board issued its list of distributors that it anticipates will be filing a Cost of Service Applications for 2013. IHDSL was included on that list.

ACCOUNTING ORDERS REQUESTED:

IHDSL is not requesting Accounting Orders in this proceeding.

COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS:

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

IHDSL has filed trial balances, financial statements and forecasted results for the 2012 bridge year, 2013 Test Year and all proceeding years in accordance with Canadian Generally Accepted Accounting Principles (GAAP).

Proforma financial statements and forecasted results of IHDSL's 2012 Bridge Year and 2013 Test Year are reported in accordance with the proposed modified International Financial Reporting Standards (IFRS) in compliance with the Board's direction.

DISTRIBUTION SERVICE TERRITORY AND DISTRIBUTION SYSTEM:

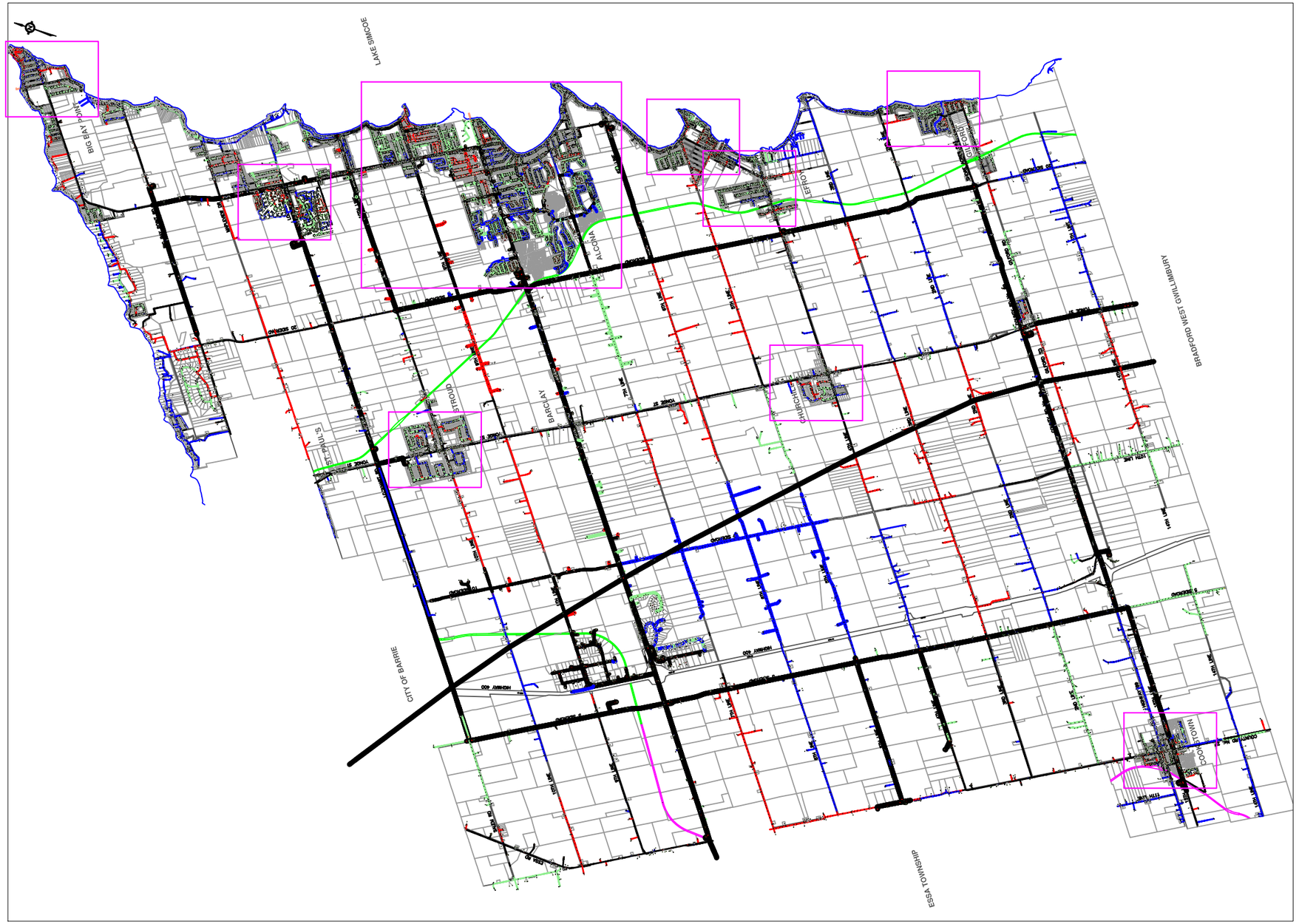
Description of Distributor:

COMMUNITY SERVED:	Town of Innisfil and South Barrie
URBAN AREAS:	71 sq km
TOTAL SERVICE AREA:	292 sq km
RURAL SERVICE AREA:	221 sq km
DISTRIBUTION TYPE:	Electricity distribution
MUNICIPAL POPULATION:	34,000
POPULATION OF URBAN AREAS SERVED:	

A map of IHDSL's Distribution Service Territory accompanies this Schedule as Appendix B.

APPENDIX B

MAP OF DISTRIBUTION SERVICE TERRITORY



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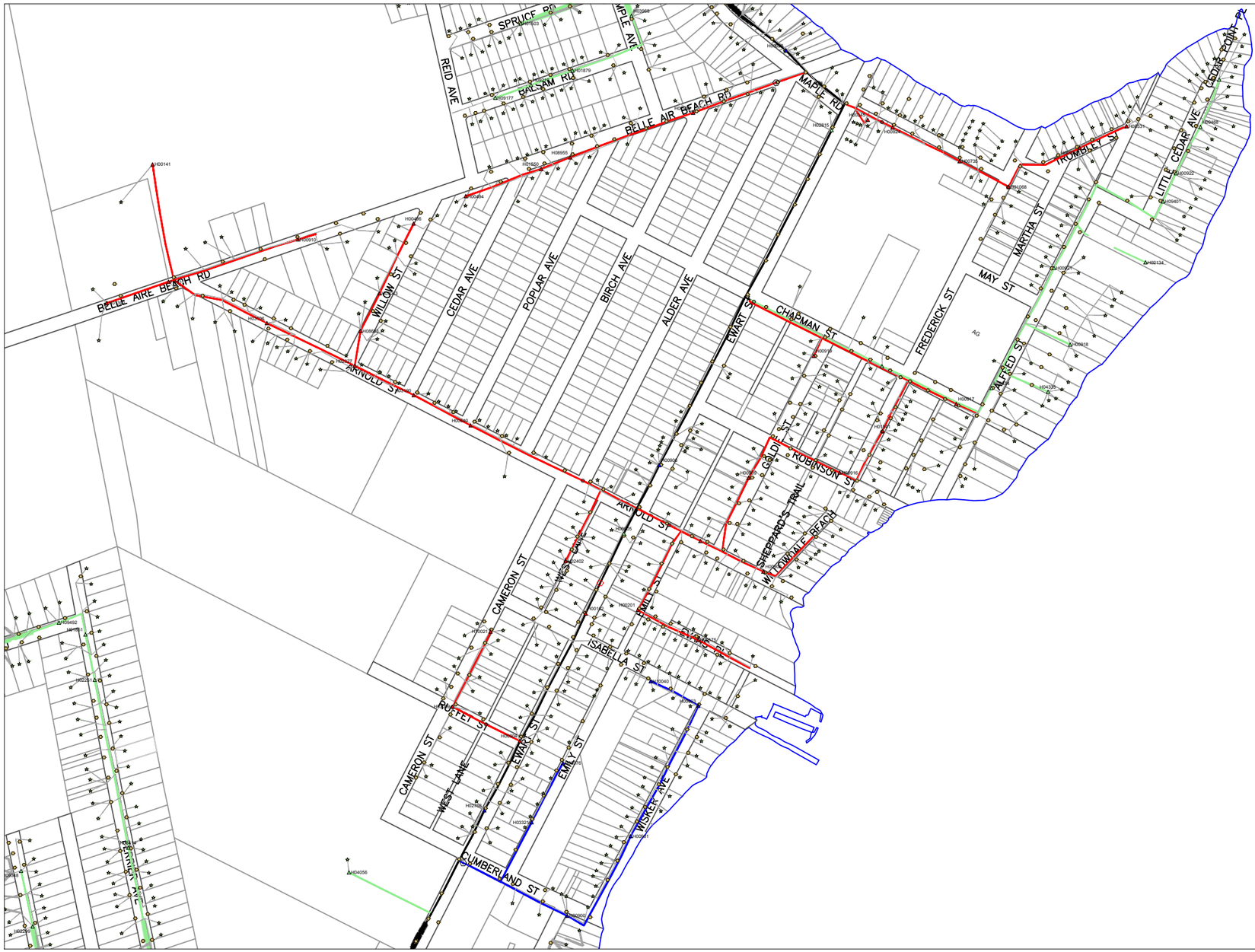

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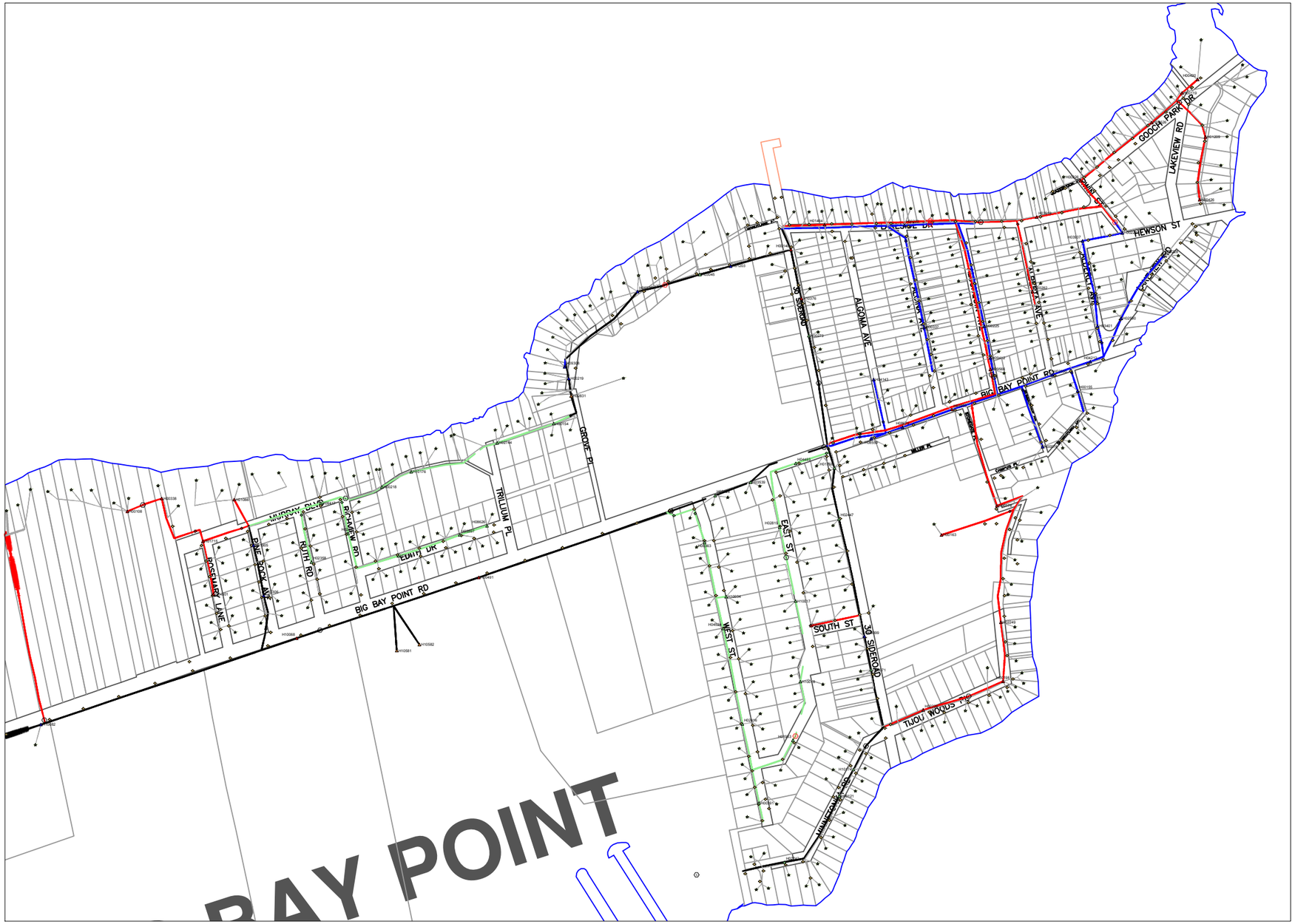

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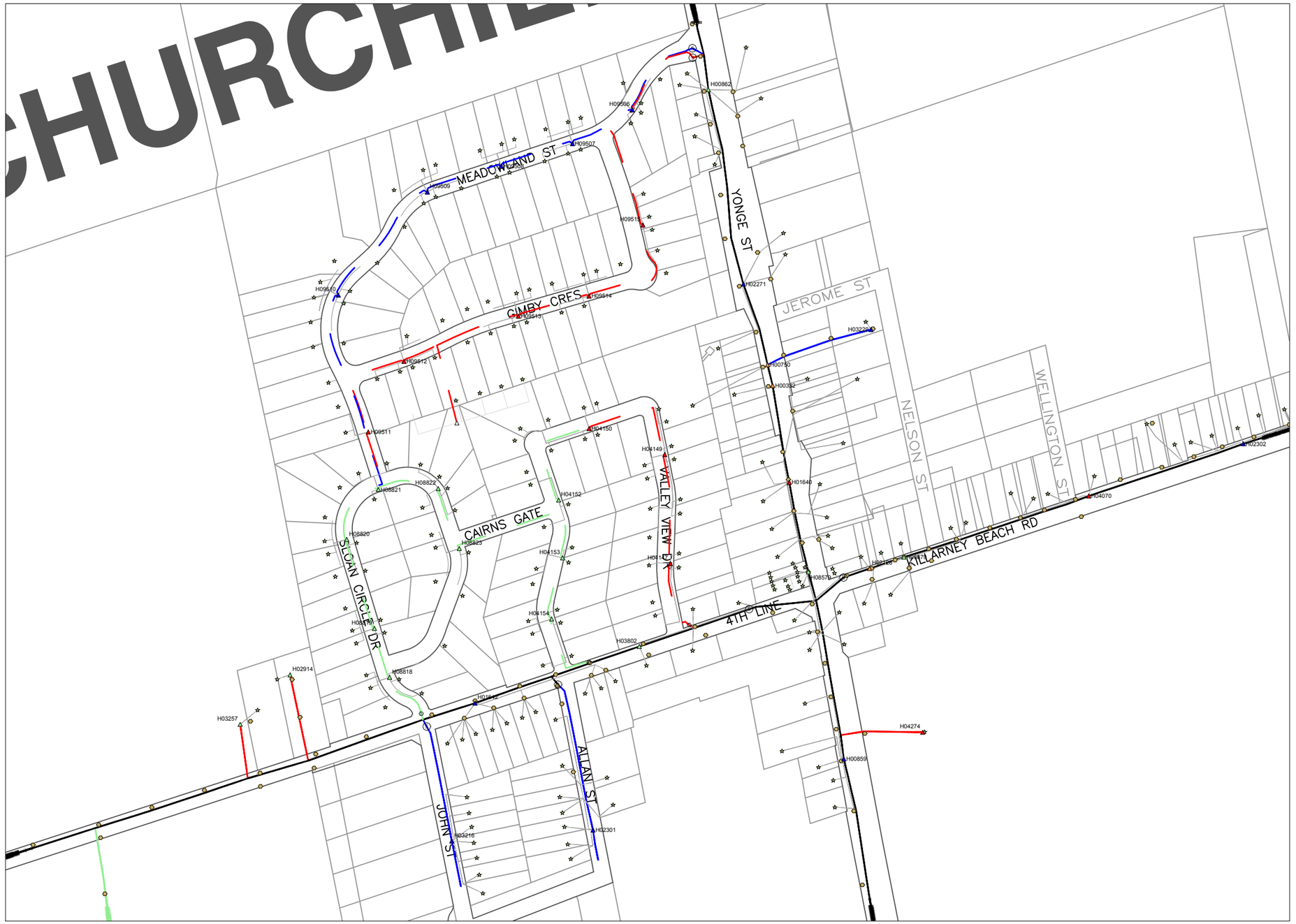

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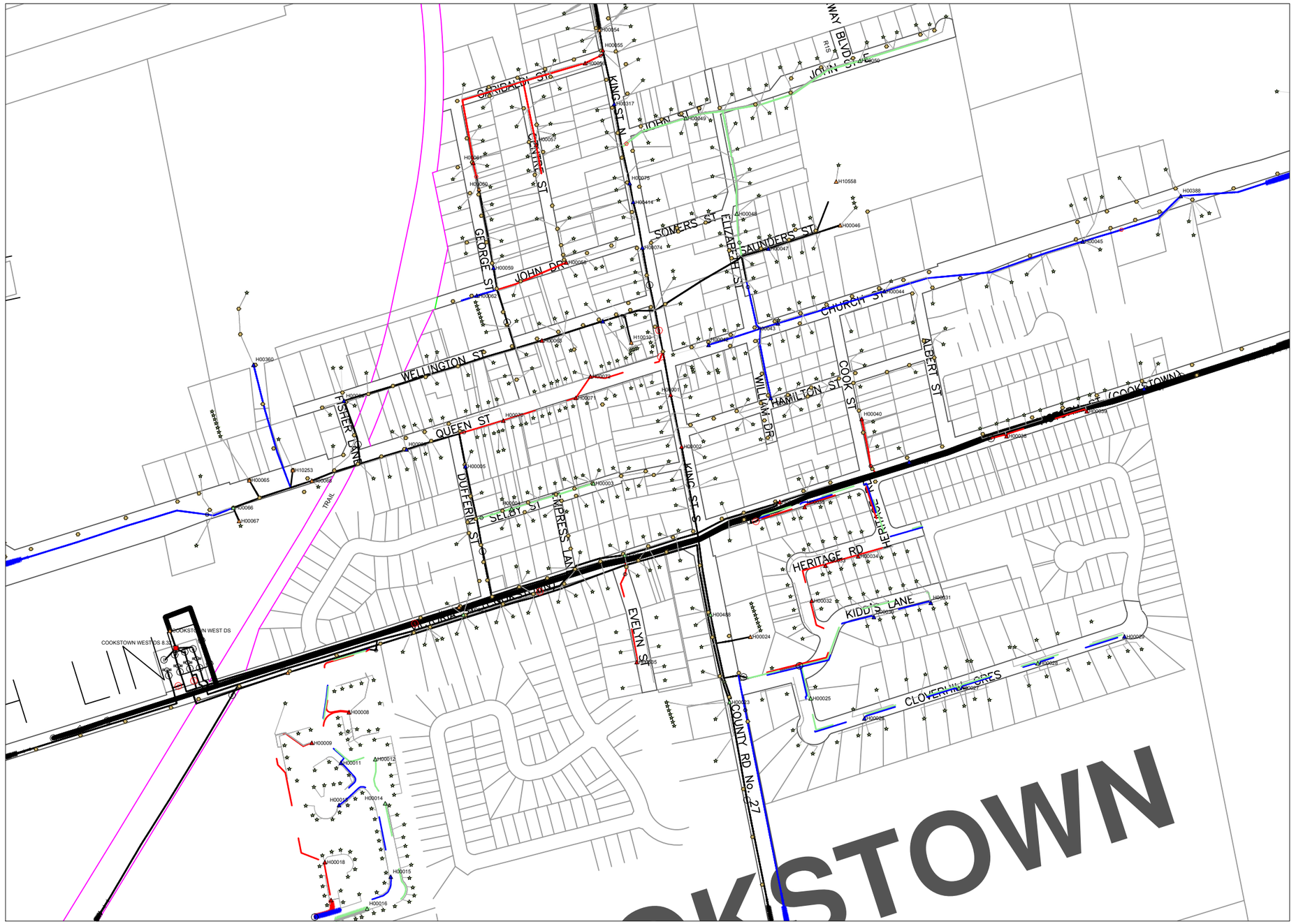

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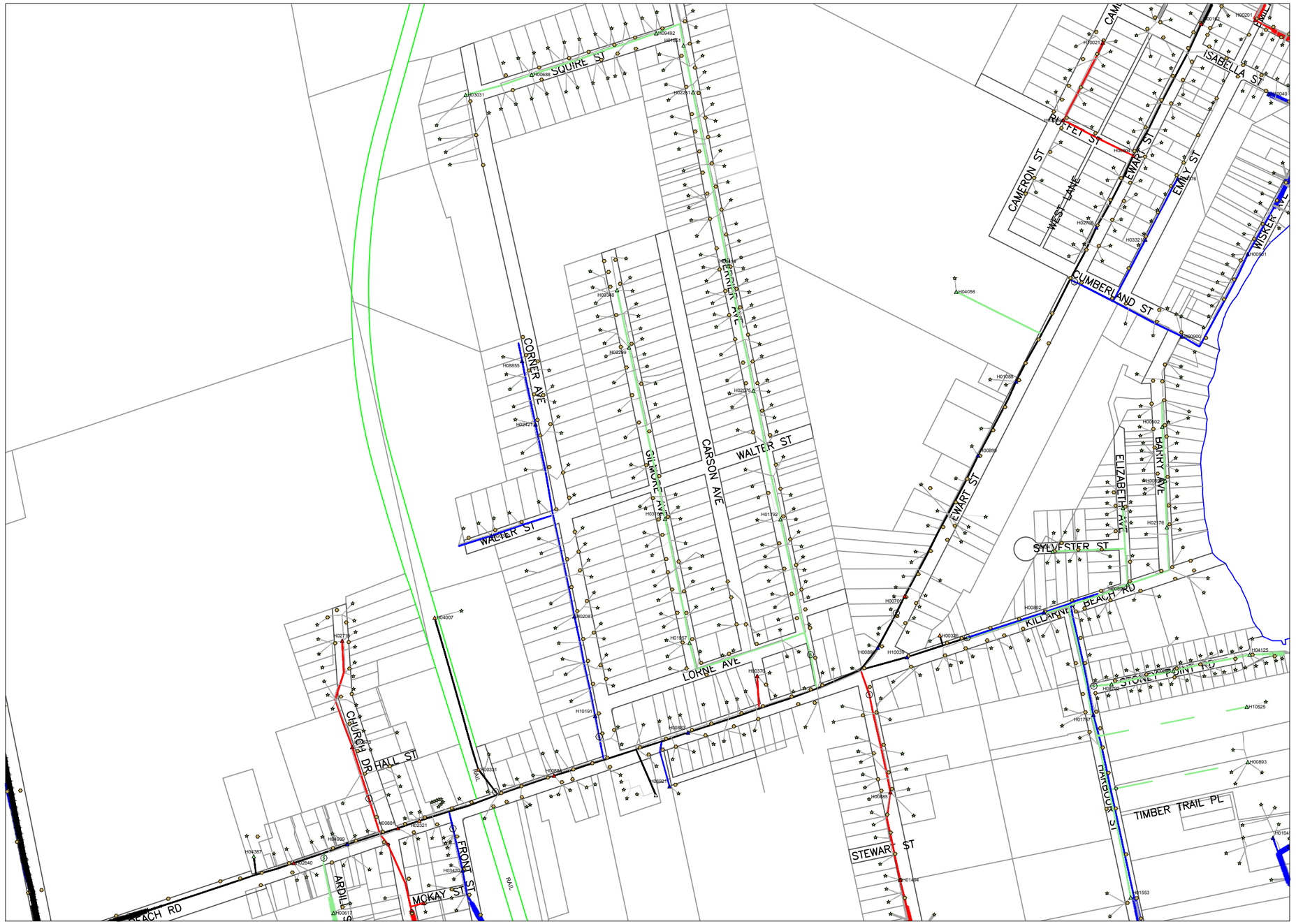

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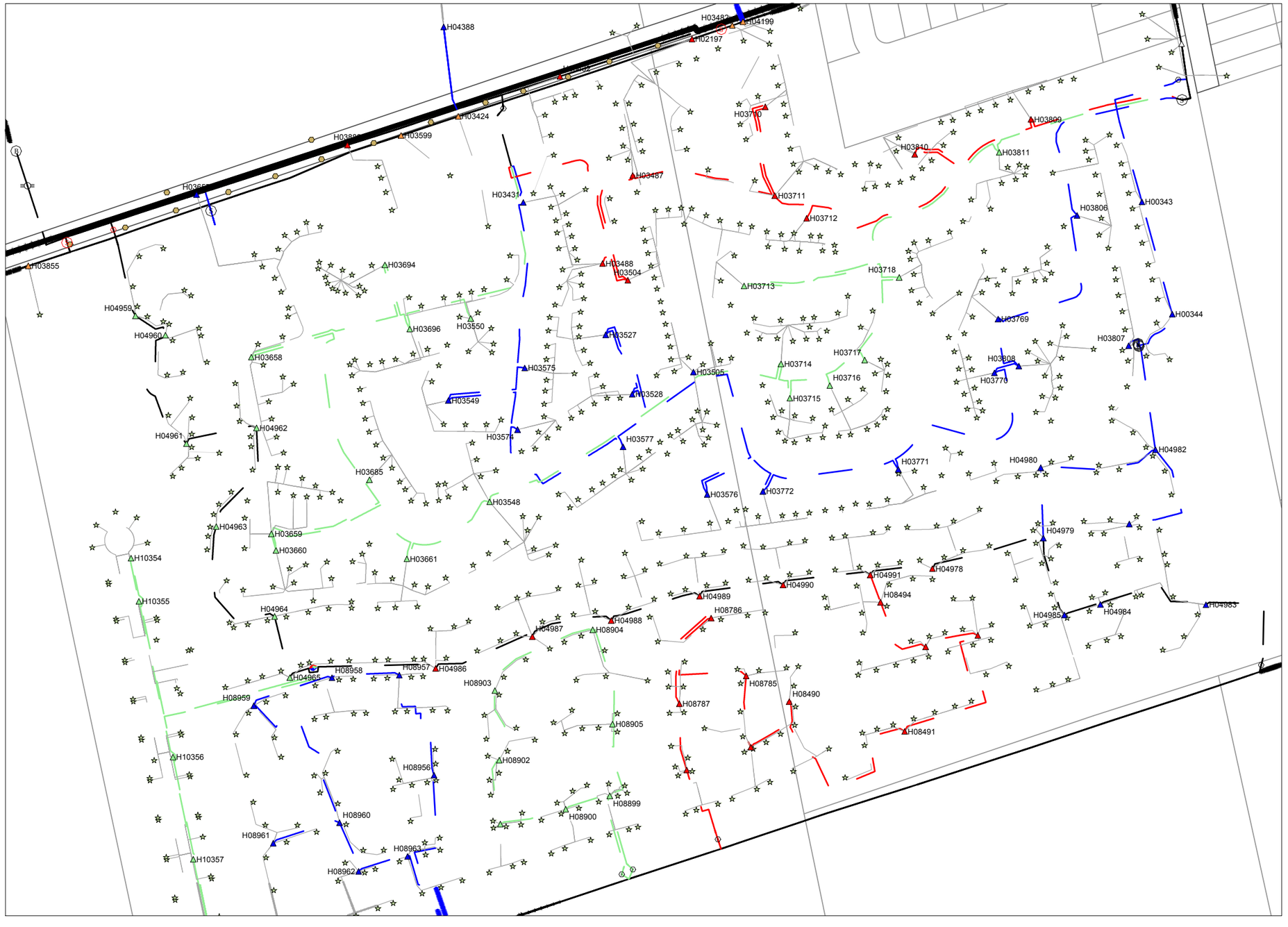
- 44KV OH CONDUCTOR
- 44KV UG CONDUCTOR
- SERVICE/SECONDARY OH CONDUCTOR
- SERVICE/SECONDARY UG CONDUCTOR
- RED ϕ CONDUCTOR
- WHITE ϕ CONDUCTOR
- BLUE ϕ CONDUCTOR
- 3 ϕ CONDUCTOR

WASFIL HYDRO

DRAWN BY	SCALE	DATE
S.L	NTS	24/08/12
REV.	DATE	BY
–	–	–
JOB TITLE		DRAWING #
IHD_ELECTRICAL_GRID		7
STREET NAME		
LEFROY		



LEGEND

ALL DIMENSIONS IN METERS

- HYDRO POLE
- RED ϕ OH TRANSFORMER
- WHITE ϕ OH TRANSFORMER
- BLUE ϕ OH TRANSFORMER
- 3 ϕ OH TRANSFORMER
- RED ϕ UG TRANSFORMER
- WHITE ϕ UG TRANSFORMER
- BLUE ϕ UG TRANSFORMER
- 3 ϕ UG TRANSFORMER
- OPEN SWITCH
- CLOSED SWITCH
- OPEN FUSE
- CLOSED FUSE
- SERVICE POINT
- RECLOSURE
- REGULATOR
- CAPACITOR
- DISTRIBUTION STATION
- 27.6KV OH CONDUCTOR
- 27.6KV UG CONDUCTOR
- 8.32KV OH CONDUCTOR
- 8.32KV UG CONDUCTOR
- 44KV OH CONDUCTOR
- 44KV UG CONDUCTOR
- SERVICE/SECONDARY OH CONDUCTOR
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- BLUE ϕ CONDUCTOR
- 3 ϕ CONDUCTOR

WISFIL HYDRO

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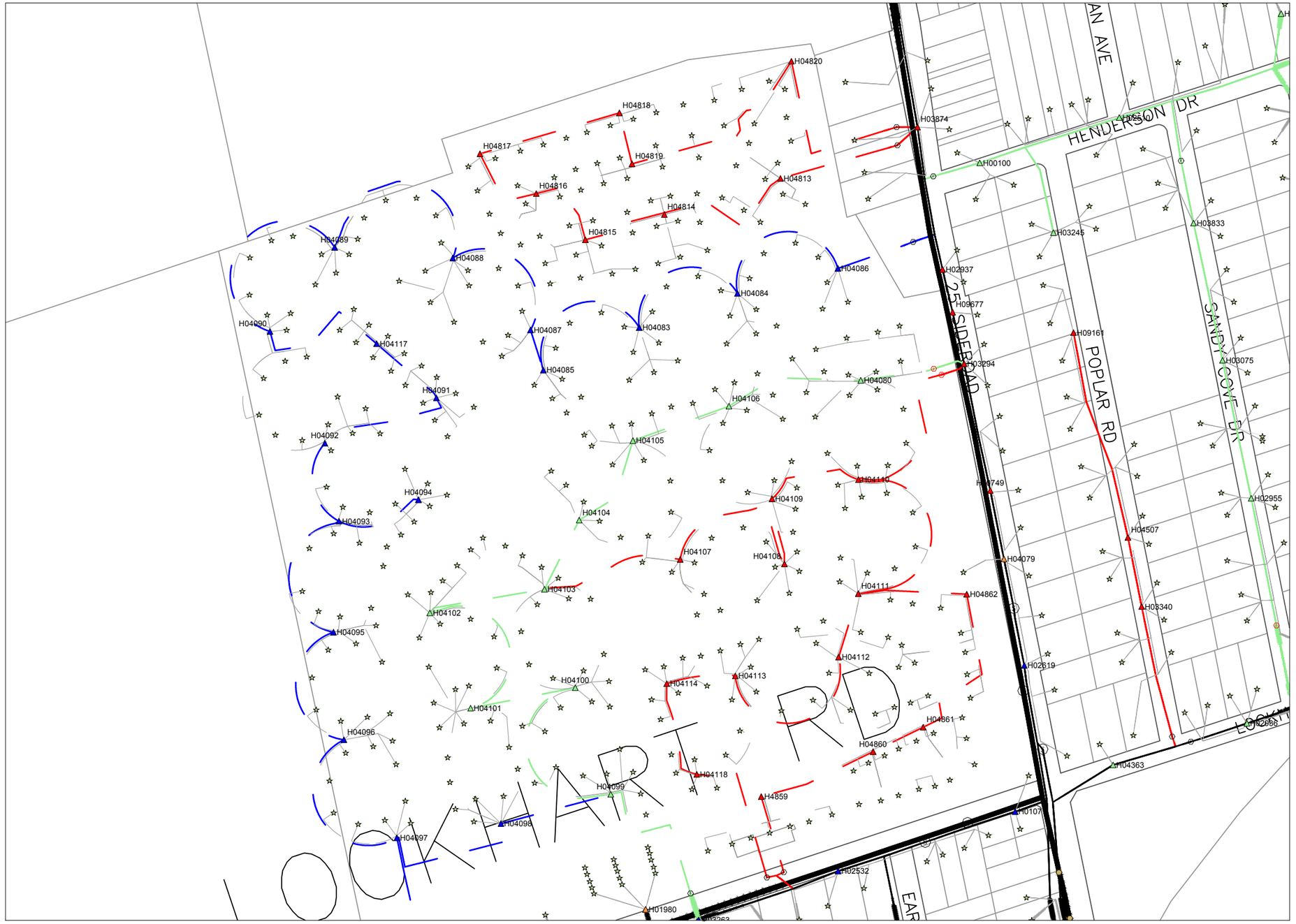
JOB TITLE	DRAWING #
IHD_ELECTRICAL_GRID	8

STREET NAME

SANDY_COVE_SOUTH



LEGEND

ALL DIMENSIONS IN METERS

- HYDRO POLE
- RED ϕ OH TRANSFORMER
- WHITE ϕ OH TRANSFORMER
- BLUE ϕ OH TRANSFORMER
- 3 ϕ OH TRANSFORMER
- RED ϕ UG TRANSFORMER
- WHITE ϕ UG TRANSFORMER
- BLUE ϕ UG TRANSFORMER
- 3 ϕ UG TRANSFORMER
- OPEN SWITCH
- CLOSED SWITCH
- OPEN FUSE
- CLOSED FUSE
- SERVICE POINT
- RECLOSURE
- REGULATOR
- CAPACITOR
- DISTRIBUTION STATION
- 27.6KV OH CONDUCTOR
- 27.6KV UG CONDUCTOR
- 8.32KV OH CONDUCTOR
- 8.32KV UG CONDUCTOR
- 44KV OH CONDUCTOR
- 44KV UG CONDUCTOR
- SERVICE/SECONDARY OH CONDUCTOR
- SERVICE/SECONDARY UG CONDUCTOR
- RED ϕ CONDUCTOR
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- BLUE ϕ CONDUCTOR
- 3 ϕ CONDUCTOR

WASFIL HYDRO

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JOB TITLE		DRAWING #
IHD_ELECTRICAL_GRID		9
STREET NAME		
SANDY_COVE_NORTH		

LEGEND

ALL DIMENSIONS IN METERS

- HYDRO POLE
- RED ϕ OH TRANSFORMER
- WHITE ϕ OH TRANSFORMER
- BLUE ϕ OH TRANSFORMER
- 3 ϕ OH TRANSFORMER
- RED ϕ UG TRANSFORMER
- WHITE ϕ UG TRANSFORMER
- BLUE ϕ UG TRANSFORMER
- 3 ϕ UG TRANSFORMER
- OPEN SWITCH
- CLOSED SWITCH
- OPEN FUSE
- CLOSED FUSE
- SERVICE POINT
- RECLOSURE
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- CAPACITOR
- DISTRIBUTION STATION
- 27.6KV OH CONDUCTOR
- 27.6KV UG CONDUCTOR
- 8.32KV OH CONDUCTOR
- 8.32KV UG CONDUCTOR
- 44KV OH CONDUCTOR
- 44KV UG CONDUCTOR
- SERVICE/SECONDARY OH CONDUCTOR
- SERVICE/SECONDARY UG CONDUCTOR
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- 3 ϕ CONDUCTOR

WMSFIL HYDRO

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S.L	NTS	24/08/12
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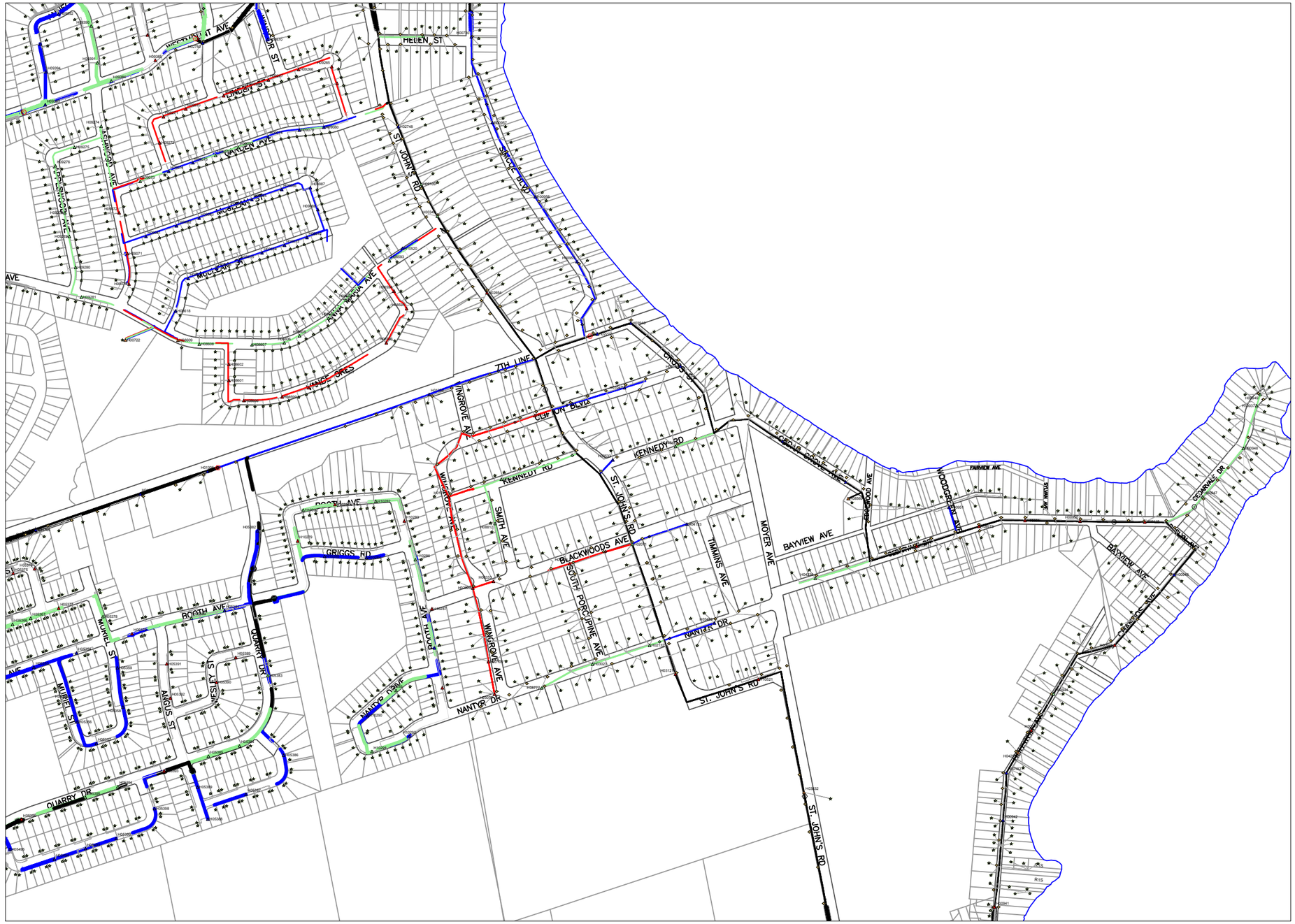
JOB TITLE	DRAWING #
IHD_ELECTRICAL_GRID	10

STREET NAME

STROUD



LEGEND

ALL DIMENSIONS IN METERS

- HYDRO POLE
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- WHITE ϕ OH TRANSFORMER
- BLUE ϕ OH TRANSFORMER
- 3 ϕ OH TRANSFORMER
- RED ϕ UG TRANSFORMER
- WHITE ϕ UG TRANSFORMER
- BLUE ϕ UG TRANSFORMER
- 3 ϕ UG TRANSFORMER
- OPEN SWITCH
- CLOSED SWITCH
- OPEN FUSE
- CLOSED FUSE
- SERVICE POINT
- RECLOSURE
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- 8.32KV UG CONDUCTOR
- 44KV OH CONDUCTOR
- 44KV UG CONDUCTOR
- SERVICE/SECONDARY OH CONDUCTOR
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- 3 ϕ CONDUCTOR

WMSFIL HYDRO

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JOB TITLE	DRAWING #
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STREET NAME

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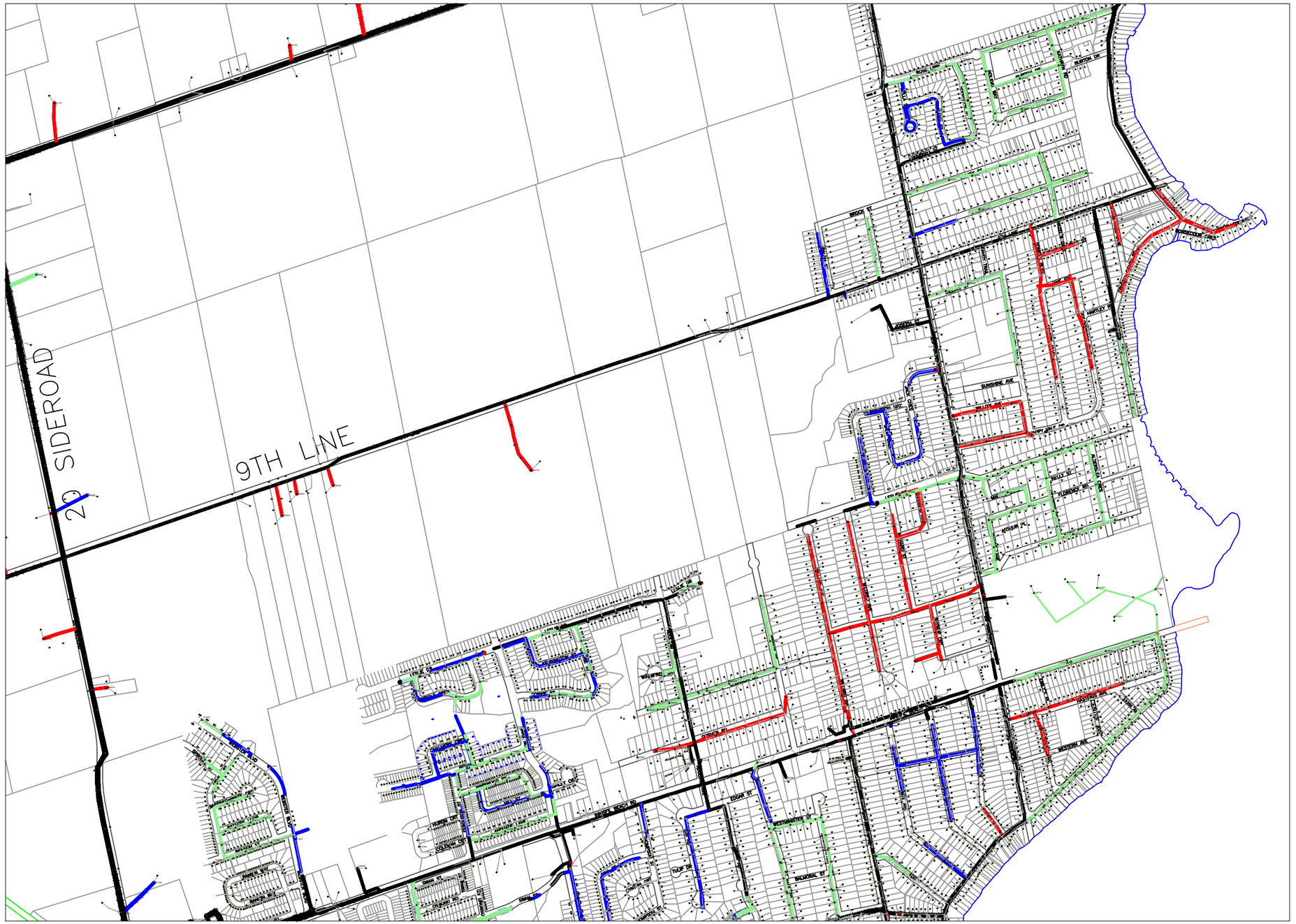
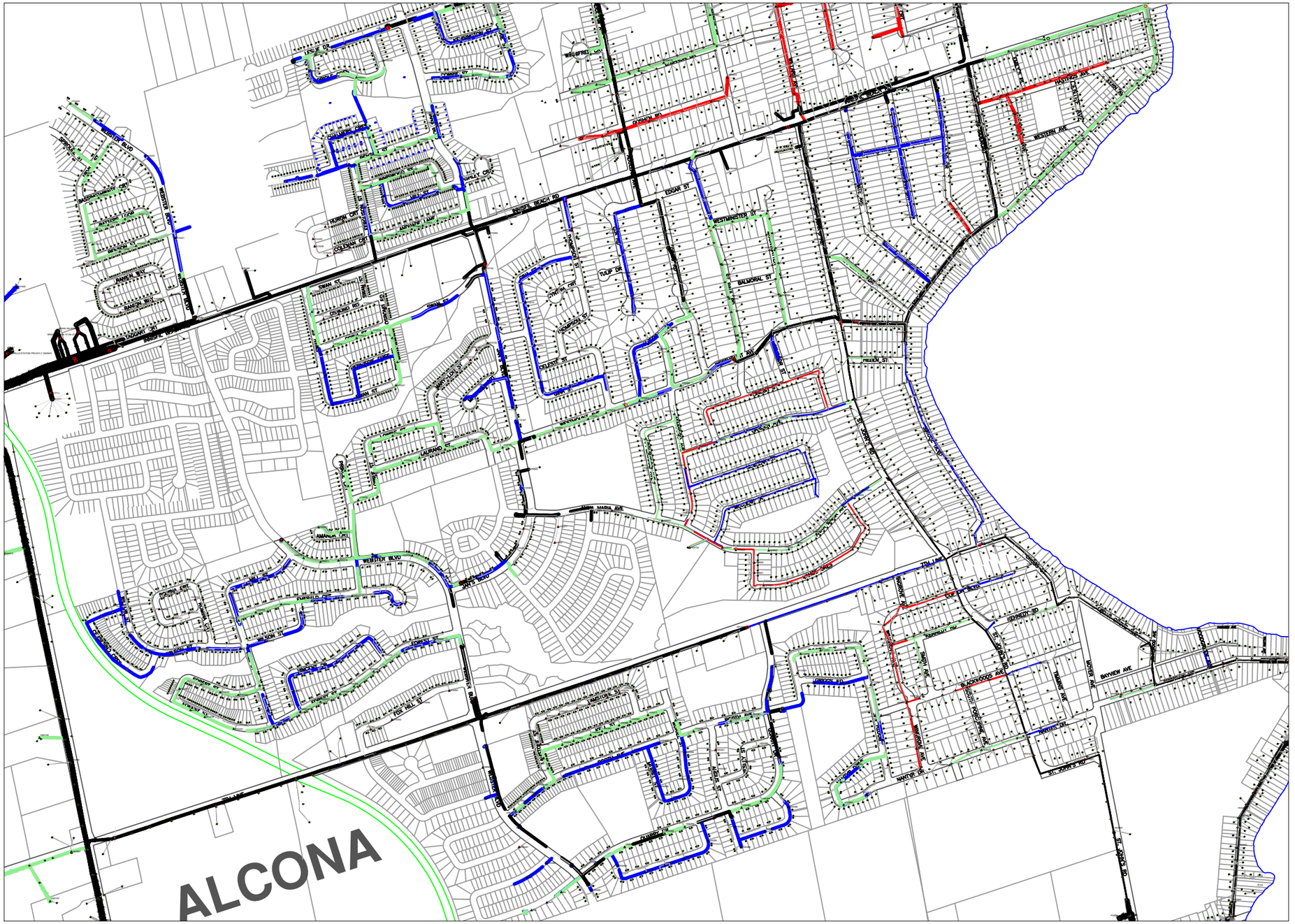
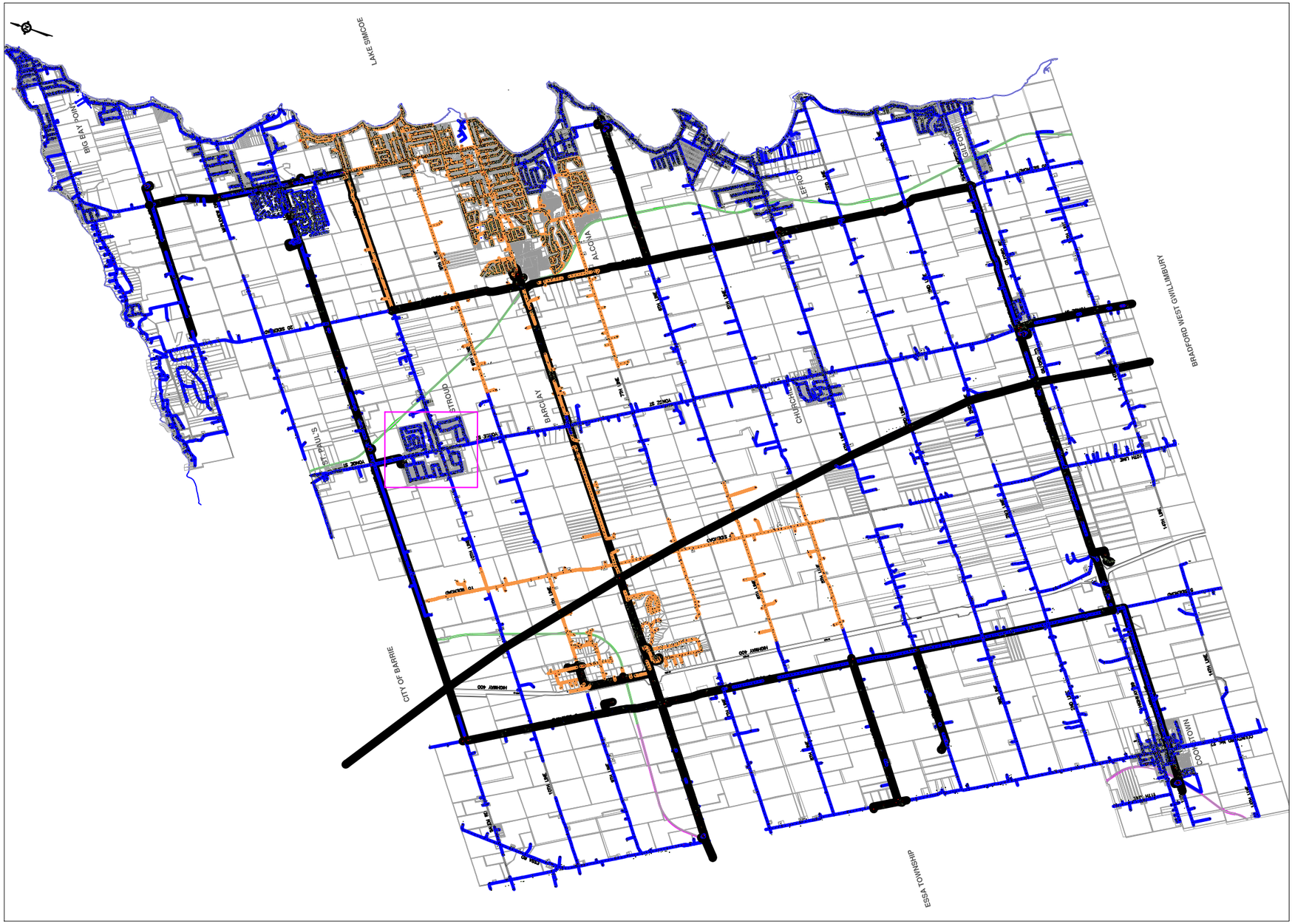

20 SIDEROAD
9TH LINE
BROCK ST
ROSSLYN CRES
ROSLIN AVE
ROSLIN CRT
ROSLIN PL
ROSLIN BLVD
ROSLIN CRES
ROSLIN CIR
ROSLIN WAY
ROSLIN DR
ROSLIN CT
ROSLIN PLACE


ALCONA
BRISTOL BEACH RD
WEBSTER BLVD
EDGAR ST
WESTMINSTER ST
BALMORAL ST
ANNE CHURCH
WESTERN AVE
HASTINGS AVE
SWAN ST
COLEMAN CRT
HURON CRT
ASHLEY CRT
RANKIN BLVD
TACHICK CRT
CROSBIE RD
CELESTE ST
THOMPSON ST
LAURAND ST
MARIA AVE
ANNA MARIA AVE
FOX HILL ST
ENGLISH ST
WESTERN AVE
THURSBY AVE
7TH LINE
BLACKWOODS AVE
BAYVIEW AVE
TUDOR AVE
NAHTOP DR
ST. JOHN'S RD
ST. JOHN'S SQ
DUNCOT RD
MOHAWK RD
ELM AVE
MAPLE AVE
PINE AVE
ROSEDALE AVE
HILLCREST AVE
ROSEMOUNT AVE
SHIRLEY AVE
HOLLY AVE
HELEN ST
OAK ST
ORCHARD AVE
ROCKLEDGE PL
ROCKLEDGE CRT
ROCKLEDGE DR
ROCKLEDGE AVE
ROCKLEDGE CIR
ROCKLEDGE CRES

APPENDIX C

MAP OF DISTRIBUTION SYSTEM



LEGEND

ALL DIMENSIONS IN METERS

- 44KV CONDUCTOR
- 27.6KV CONDUCTOR
- 8.32KV CONDUCTOR

INNISFIL HYDRO

DRAWN BY	SCALE	DATE
S.L	NTS	24/08/12
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JOB TITLE: IHD_ELECTRICAL_GRID		DRAWING #: 14
STREET NAME: 44KV/27. 6KV/8. 32KV_MAP		

LIST OF NEIGHBOURING UTILITIES:

IHDSL neighbouring utilities are Barrie Hydro and Hydro One Systems.

POWER STREAM BARRIE HYDRO	Direct Line: 705-722-7222
55 Patterson Road	Direct Fax: 705-722-6159
Barrie, ON L4M 4V8	Website: www.powerstream.ca

HYDRO ONE NETWORKS INC.	Direct Line: 416-345-5000
483 Bay Street	Direct Fax: 416-345-5870
Toronto, ON M5G 2P5	Website: www.HydroOne.co

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 STRUCTURE:

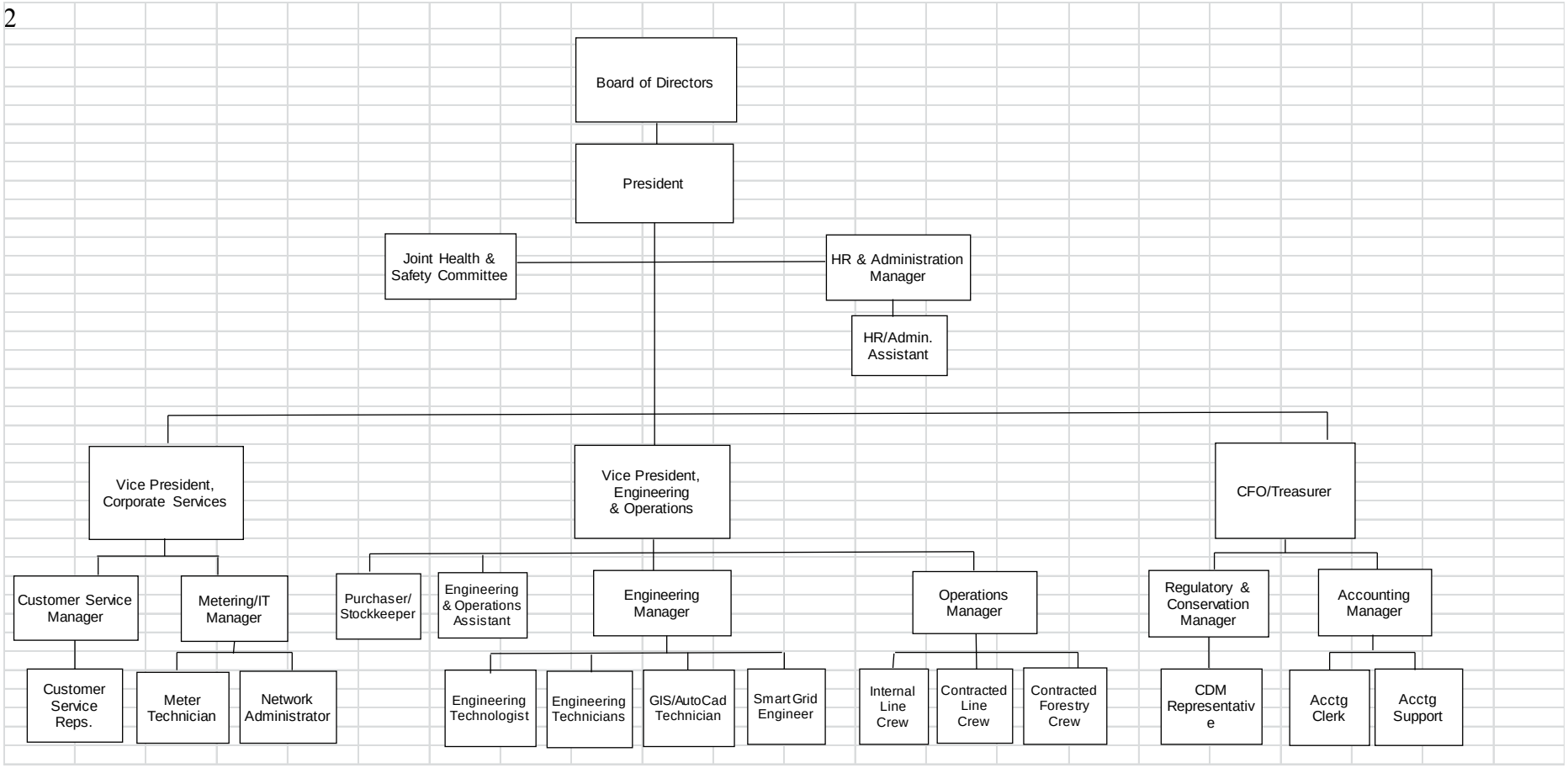
Innisfil Hydro Distribution Systems Limited

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.

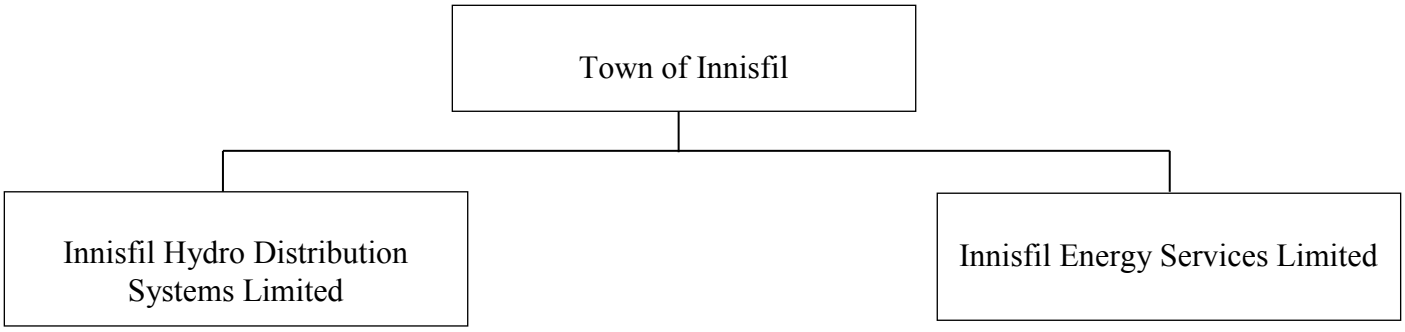
Innisfil Energy Services Limited

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 were estimated to cease in January 2009. IESL has continued to operate the sentinel light rentals with minimal cost causality from IHDSL, resulting in a reduction in excess of 80%.

Schedule – Corporate Organizational Structure



CORPORATE ENTITIES RELATIONSHIP CHART:



PLANNED CHANGES IN CORPORATE AND OPERATIONAL STRUCTURE:

No changes to IHDSL'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.

PRELIMINARY LIST OF WITNESSES:

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

CONDITIONS OF SERVICE:

IHDSL revised the Conditions of Service in 2011, due to changes with respect to distributed generation.

The current Conditions of Service are published on IHDSL's website (www.innisfilhydro.com) and are included as Appendix D.

APPENDIX D

CONDITIONS OF SERVICE

Conditions of Service

For

Cornerstone Hydro Electric Concepts Association

Prepared July 2011

CONDITIONS OF SERVICE

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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 Distribution Licence issued to the Distributor by the OEB. Additionally there are requirements imposed on the Distributor by the various codes referred to in the Licence and by the Electricity Act, the Ontario Energy Board Act and other provincial legislation.

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

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: Electrical Safety Authority (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, temporary power services and generation connections.

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 Safety 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 or
(c) the availability of adequate capacity for generation to be connected to the specific location.

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' plant that has been damaged through the customers' action or neglect.

The supply of electricity or a service connection 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 some instances an Economic Evaluation as defined in the Distribution System Code (DSC) may be required. Customers installing distributed generation may be required to pay for additions of new or upgraded Distributor electrical plant associated with the connection of the generation and the associated engineering studies.

1.2 Related Codes and Governing Laws

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

1. *Electricity Act, 1998*
2. *Ontario Energy Board Act, 1998*
3. *Green Energy Act*
4. *Energy Consumer Protection Act, 2010*
5. *Distribution Licence*
   Licence Numbers
6. *Affiliate Relationships Code*
7. *Distribution System Code*
8. *Retail Settlement Code*
9. *Standard Service Supply Code*
10. *Conservation and Demand Management Code*
11. *Transmission System Code*
12. .*Ontario Regulation 22/04* - Electrical Distribution Safety *Electrical Safety Authority ESA)*
13. *Measurement Canada*
14. *Electricity and Gas Inspection Act*

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 Licence 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 Electrical Utility Safety Rules (IHSA formally EUS&A) (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 notice shall be provided to customers as required in the Distribution System Code and copies made available at the Distributor's office or 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.

1.9 Service Quality Requirements

The level of service provided by the Distributor is defined in specific terms within Section 7 of the DSC. The Distributor recognizes the requirements and will strive to meet or exceed these requirements and the associated reporting to the OEB. The reporting of these requirements forms public record available to the Distributor's customers.

1.10 Liability

A distributor shall only be liable to a customer and a customer shall only be liable to a distributor for any damages which arise directly out of the willful misconduct or negligence:

1.0 Of the distributor in providing distribution services to the customer;
2.0 Of the customer in being connected to the distributor's distribution system; or
3.0 Of the distributor or customer in meeting their respective obligations under the Distribution System Code, their licences and any other applicable law.

Despite the above; neither the distributor nor the customer shall be liable under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in contract, tort or otherwise.

1.11 Force Majeure

Neither party shall be held to have committed an event of default in respect of any obligation under the Distribution System Code if prevented from performing that obligation, in whole or in part, because of a force majeure event.

Notwithstanding any of the foregoing, settlement of any strike, lockout, or labor dispute constituting a force majeure event shall be within the sole discretion of the party to the agreement involved in the strike, lockout, or labour dispute. The requirement that a party must use its best efforts to remedy the cause of the force majeure event, mitigate its effects, and resume full performance under the Distribution System Code shall not apply to strikes, lockouts, or labour disputes

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 Obligations to Connect

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.

As provided in Section 25.36 of the Electricity Act 1998 the Distributor shall connect a renewable energy generation facility to its distribution system in accordance to regulations, the market rules and any licence issued by the Board if requested and all regulations, market rules, orders or code have been met in respect to the connection.

Connection fees as noted within the Conditions of Service shall apply. (See sections 3.1.3, 3.1.4, 3.2.3, 3.2.4, 3.3.3, 3.3.4 3.4.3, 3.4.4, 3.5.1 & 3.8.1)

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 System 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.

The Distributor may require a customer proposing to install generation to pay the costs of electrical plant installed to facilitate the connection of the generation. Such capital contributions will be calculated using the guidelines set by the OEB in the Distribution System Code. The Customer proposing a generation project should review the CHEC Generation Guide and Appendix E and Appendix F of the Distribution System Code for further information and direction on the technical and administrative requirements.

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 customer 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 including the Ontario Electrical Safety Code.
- 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 may be required when 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*

In all cases of special contracts the terms and conditions of all regulations, conditions and charges as established by the Distributor shall apply to the customer connection unless specifically noted in the special contract.

2.2 Disconnection

The Distributor has the right and/or obligation to disconnect the supply of electrical energy or service 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.

Disconnection of service shall follow the Distributor's Disconnection/Reconnection Policy.

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.

Customers requiring power for human life support equipment must provide their own equipment to ensure an uninterrupted supply of power. Customers on life support equipment are encouraged to contact the Distributor to inform them of their medical needs and the backup equipment which is in place.

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, generators 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.

The customer installing generation will install a Distributor approved system configuration and voltage level. In general where the connection of generation will be to the service supply the generation will be required to be the same voltage and number of phases.

2.3.4 Standard Voltage Offerings

2.3.4. 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 Volts single phase, or*
- *120/208 Volts three phase, four wire, or*
- *347/600 Volts 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 Volts single phase, or*
- *at 120/208 Volts three phase, four wire, or*
- *at 347/600 Volts 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*
- *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 specifies maximum variations from "normal operating conditions" and 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.

Where concern exists with the service voltage level customers are encouraged to contact the Distributor to confirm the allowed variations and to determine whether corrective action is required.

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 Ontario Electrical Code which specifies the requirements for the connection of generators and to further review the Standby Generator Safety Checklist review Generator Safety Info.

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. Where primary metering is utilized the customer may own the current and potential transformers.

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.

Individual suite metering can be installed and operated by the Distributor or private unit sub-metering providers. The installation and operations of systems will comply with the requirements as outlined in the Energy Consumer Protection Act, 2010 S.O. 2010, Chapter 8.

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.

2.3.7.1.8 Maintenance of Metering Equipment

The customer is responsible for maintaining the integrity of the meter base and cabinets, unless owned by the LDC, to meet the required mechanical and electrical standards.

For residential meters the meter base is considered customer owned and is to be maintained by the property owner. Any requirement for maintenance should be coordinated with the Distributor and completed in accordance to all applicable standards.
Commercial/Industrial installations result in varying ownership of cabinets and equipment. The property owner is to maintain any metering equipment under their control. Any requirement for maintenance should be coordinated with the Distributor and completed in accordance to all applicable standards.

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.

When the communication system relies on radio frequency the Owner will facilitate the provision of a location of an external antenna. The distributor will install the antenna and the associated wiring.

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. Metering requirements for Large General Service customers will be reviewed in concert with any new Regulations.
Where the customer installation requires by-directional metering (example for generation connections) the additional cost of the metering may be charged as an additional fee.

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.

Where Smart Meters are installed the final reading can be accommodated through remote interrogation. If at the time of final read remote access to the meter is not available an estimate of consumption will be made based on meter reading system data calculated to estimate the final billing.

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.

Where the distributor has under billed a customer or retailer, the maximum period of under billing for which the distributor is entitled to be paid will be as specified in the latest revision of the Acts and Codes. Where the distributor has over billed a customer or retailer, the maximum period of over billing for which the customer or retailer is entitled to be repaid will be as specified in the latest revision of the Acts and Codes.

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 as per the Federal Electricity and Gas Inspection Act.

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.

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.

Customers considering generation should review feed in tariff (FIT) programs which may be operating at the time. Reference to the CHEC Generation Guide and Appendix E and Appendix F of the Distribution System Code may prove instructive.

2.3.7.18 Metering for Embedded Generation

Generating facilities 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. The generator will be responsible for costs associated with the connection to the distribution system and any required metering installation as defined by the relevant Codes and Acts.

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 a licensed 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. Under special circumstances the Distributor may require more frequent payment.

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.

These charges are typically the commodity charges related to energy however do not need to be limited to same.

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.

These charges can include but are not limited to; distribution charges, transmission charges, global adjustments.

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 due when rendered by the utility and are payable in full by the due date. A customer may pay the bill without the application of a late payment charge up to a due date as specified in the Distribution System Code. This due date shall be identified clearly on the customer's bill.

Where payment is made by mail or at a financial institution, payment will be deemed to be made consistent with the requirements in the Distribution System Code.
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 or the conditions of the Distribution System Code outlines an alternate process.

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.

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 3 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 plant.

3.1.8 Metering:

The owner will supply and install a meter socket complete with collar acceptable to the Distributor and which meets the Ontario Electrical Safety Code. 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 Basic Connection Charge

All costs attributed to the connection of a new General Service customer (Below 50 kW) shall be recovered either as part of the Distributor's revenue requirements or through a basic connection charge to the customer.

3.2.4 Variable Connection Charge

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 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 3 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 Distributor's 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 Basic Connection Charge

All costs attributed to the connection of a new General Service customer (Above 50 kW) shall be recovered either as part of the Distributor's revenue requirements or through a basic connection charge to the customer.

3.3.4 Variable Connection Charge

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 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 plant.

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 Basic Connection

All costs attributed to the connection of a new General Service customer (Above 500 kW) shall be recovered either as part of the Distributor's revenue requirement or a basic connection charge to the customer.

3.4.4 Variable Connection Charge

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 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 plant.

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 the regulators' registration requirements, permits and inspections as required, including ESA and Licences as appropriate.

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 but are not limited to costs associated with:

- Preliminary review for connection requirements.(Connection Impact Assessment)
- Detailed study to determine connection requirements. (Cost of Connection)
- Final proposal to the generator.
- Connection costs for construction or make ready work for the distribution system as per the cost allocation methods in the DSC.

A Generator that is or wishes to become connected to the distributors' distribution system shall enter into a Connection Agreement with the Distributor as prescribed in Appendix E of the DSC.

A generator shall ensure that a disconnection method suitable to the Distributor is installed to provide visible isolation of the generation.

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 protection 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 greater than 10 kW must submit a proposed single line diagram and protection scheme signed and sealed by a Professional Engineer in the Province of Ontario 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.

In addition to the forgoing the CHEC Generation Guide can be referred to for further details with respect to the connection process and Appendix F of the Distribution System Code.

The generator in addition to the requirements of the host LDC may be required to meet the conditions of upstream LDCs. The additional requirements will be communicated through the host LDC.

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.

Prior to completing any testing or repairs on the system the Distributor shall be contacted to coordinate the work.

- 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 plant.

- 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.

- Testing & inspection requirements specified by the Distributor.

3.5.6 Post Connection Changes

Any changes to the system after the initial connection will be communicated to the Distributor prior to implementation.

Where any of these proposed changes alter the protection associated with the installation the Distributor will be provided with sufficient information to allow review of the protection scheme and the potential impacts on the distribution system.

Where the customer makes changes which result in the need for additional studies, protection changes or alterations to the distribution system the customer will be responsible for the costs incurred by the Distributor as allowed by the various codes and regulations.

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.

These small services may be required to be metered by the Distributor.

To facilitate these installations the Distributor may have standard designs which are to be followed by parties requesting the attachment.

In addition any attachments made to the Distributor's system will be required to conform to Ontario Regulation 22/04 and Ontario Electrical Safety Code. The Distributor will provide direction to the Owner with respect to any special requirements under Regulation 22/04.

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
120/208 volts, three phase, four wire
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 will install required transformation and may charge the Owner the cost.

Where at the discretion of the Distributor a meter is not installed, energy consumption will be based on the connected wattage and the calculated hours of use. With the advent of Smart Metering the metering of actual consumption data is available and preferred by most Distributors. Meter installations may be required by Distributors.

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

The Owner will be required to maintain any equipment in proper and safe working order. Where the equipment is found to be in disrepair or present a hazard the Distributor may disconnect, remove and charge the costs to the owner.

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.

The Distributor after reviewing the information provided may require the owner to provide further information or approved drawings signed by a Professional Engineer ensuring that the installation is consistent with the requirements of Regulation 22/04.

3.8.3 Street Lighting

Where the street lighting is installed, owned and maintained by the Municipality or a third party, a Joint Use Agreement may be required for attachment to the Distribution system. Installations shall meet Ontario Regulation 22/04 and Ontario Electrical Safety Code.

The owner will be required to ensure qualified personnel are engaged to work on the streetlight system and that the system is maintained in a manner as to not represent a hazard to the distribution system and the public.

Proper records of the street light system shall be maintained by the owner to facilitate identification of equipment, appropriate record management and the ability to locate any underground plant associated with the system.

3.8.4 Traffic Signals

Traffic Signals and Crosswalk Lights are owned and maintained by the applicable road authority. Any traffic signals and crosswalk lights, if attached to the distribution system will be required to be in compliance with Regulation 22/04.

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.

Where such lighting represents a barrier to distribution system maintenance the Distributor may remove to facilitate work on the system in a safe manner. The owner will be responsible for reinstalling any equipment removed by the Distributor.

3.9 Attachments to Distribution Plant

The Distributor reserves the right to refuse any attachment to the Distribution Plant.

Customer attachments require written consent of the Distributor. Generally, consent will only be provided to licensed franchisees such as Bell Canada, Rogers Cable, and registered Telecom Companies. The Distributor reserves the right to refuse attachments to its poles.

Pole attachments will require a signed contract between the Distributor and the customer. Each pole attachment is subject to a yearly joint use charge and installation must conform to Regulation 22/04. Requesting parties will be responsible for meeting the requirements of Regulation 22/04 and the associated costs. No customer owned wires or apparatus are to be installed on the Distributor's poles prior to entering into a contract and confirming that the installation meets the requirements.

Where make ready work is required to accommodate the requested attachment the requesting party will be responsible for all costs associated with the make ready work.

Any attachments not approved will be removed by the Distributor at the owner's expense.
To meet engineering, safety, congestion and aesthetic considerations only three locations are generally allowed for the attachment of support strands and communications cables in the communication space of the Distributor's poles. Each customer requesting attachment in the communication space is allowed to install one support or communications cable only and this applies to all its associates as defined by the Ontario Business Corporation Act.

The owner of any third party plant shall be responsible to maintain their plant in a safe and proper condition compliant with Regulation 22/04 and relevant standards including any specific Distributor Standards.

The owner of any third party plant will be responsible for transfers of their plant in a timely manner as required by the Distributor.

3.9.1 Miscellaneous Attachments

Owners of miscellaneous equipment wishing to attach to the Distributor's system shall make written application for review and where appropriate approval by the Distributor.

Failure to obtain written authorization from the Distributor and or to enter into a Joint Use Agreement will result in the removal of the equipment and any associated plant by the Distributor at the owner's expense.

3.9.2 Joint Use Agreements

This section pertains to owners of plant who wish to make attachments to the Distribution System which have a direct or indirect influence on the performance, appearance and safety of the support structure or the Distributor's ability to make access and maintain it. For greater clarity this section applies to companies such as communication companies, CATV companies, and municipalities, but may be extended to others interested in making attachments.

All construction, installation and maintenance of attachments by the third party will conform to Ontario Regulation 22/04 and follow the appropriate guidelines. The requirements of Regulation 22/04 provide direction on design, material standards, construction and verification of the installations.

To facilitate good construction and project planning and compliance with Regulation 22/04 any party requesting to make an attachment shall contact the Distributor in writing well in advance of the proposed installation date.

Prior to making any attachments the owner of the plant will be required to enter into a Joint Use Agreement with the Distributor or if a Joint Use Agreement has been previously entered into, to follow the process for new attachments or modifications to existing attachments as specified in the Joint Use Agreement.

The owner of any third party plant shall be responsible to maintain their plant in a safe and proper condition compliant with Regulation 22/04 and the conditions of the Joint Use Agreement.

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;

"Distributed Generation" means any type of electrical generator or static inverter producing alternating current that has the capability of Parallel Operation with the LDC distribution system, or is designed to operate separately from the LDC system and can supply a load that can also be fed by the LDC system.

"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;

"Feed in Tariff (FIT)" means the provincial Renewable Energy Feed-In Tariff (FIT) Program for the Province (or programs which may operate from time to time) to encourage and promote greater use of renewable energy sources including wind, waterpower, renewable biomass, bio-gas, bio-fuel, landfill gas and solar for electricity generating projects that can be connected to a host facility, a distribution system or the IESO-Controlled Grid, in Ontario. The fundamental objective of the FIT Program, in conjunction with the Green Energy Act (Ontario), is to help facilitate the increased use in the Province of Renewable Generating Facilities of varying sizes, technologies and configurations via a standardized, open and fair process.

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

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

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

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

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

"Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired

result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"Ontario Energy Board Act" means the *Ontario Energy Board Act, 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*;

"Regulation 22/04" Electrical Distribution Safety: means the regulation made under the Electricity Act establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors.

"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 licence to distribute electricity;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

SECTION 5 APPENDICIES

Contact Information

Distribution Connection Process

Request For Connection Form

Electrical Planning Requirements Document

Electric Service Meter Base/ Service Verification Form

POLICIES Relevant to Conditions of Service – Contact LDC to obtain the most recent copy of the policy

Policy 6.0 – Security Deposit

Policy 6.2 – Billing and Payment

Policy 8.1 – Disconnection/Reconnection

Policy 9.3 – Environmental Policy

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
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
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. L9ZL 1A2
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
West Coast Huron Energy Inc.		57 West Street
Licence # ED-2002-0510	Phone: (519) 524-7371	Goderich, Ont. N7A 2K5

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

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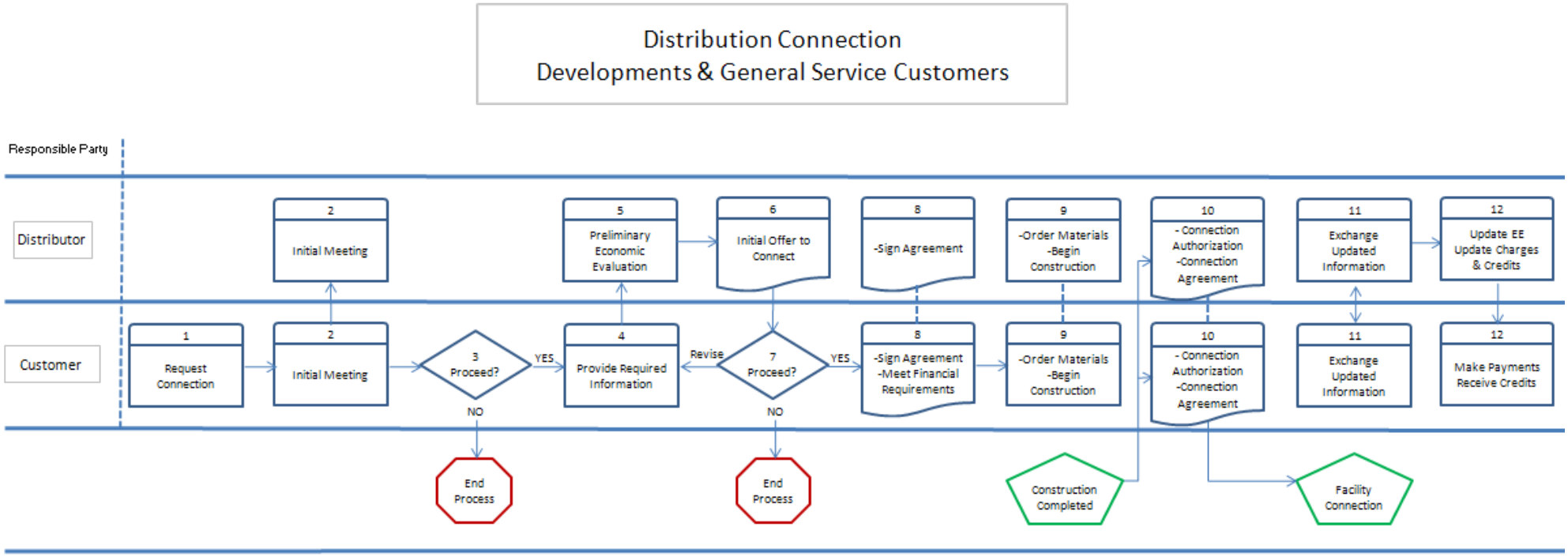
Distribution Connection

For Generation please see the CHEC Generation Guide



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 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 – Sample Form

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	

Type & Number of Connections:

		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:	

Cornerstone Hydro Electric Concepts Association Inc.

Electrical Planning Requirements

It is essential that the following information be provided to:

a) enable an assessment to be made on the impact of the proposed project on the Electrical Distribution System.
b) enable the Distributor to prepare pertinent information for the developer.

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

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

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

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

Name of Project: _____

Name of Applicant: _____

Address: _____

Contact Name: _____

Address: _____

E-Mail: _____

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

Service Classification (☒ as many as apply):

- ☐ Residential
- ☐ General Service < 50kW
- ☐ General Service > 50kW
- ☐ General Service >500kW
- ☐ Unmetered or Miscellaneous Load
- ☐ Temporary Service

What service voltage is required (☒ one only):

- ☐ 120/240 Volt Single Phase
- ☐ 120/208 Volt Three Phase
- ☐ 347/600 Volt Three Phase
- ☐ Primary

Required In-Service Date:

Month / Day / Year _____/_____/_____

Service Entrance Switchboard with Utility CT and PT Compartment ☐ Yes ☐ No

Capacity of Main Service (in Amperes):

Maximum rated capacity: _____

Estimated Connected Load in kW:

Maximum initial Load: _____ kW

Maximum Future Load: _____ kW

Metering Type (☒ one only):

- ☐ Single Meter
- ☐ Multiple Meters

Quantity of Meter installations

100A or less: _____

101A to 200A: _____

more than 200A: _____

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

Signed: _____ **Date:** _____

(Representative of Applicant)

Name: _____ **Title:** _____

Electric Service Meter Base/Municipal Address Verification Form – Sample

LOCAL DISTRIBTUION COMPANY NAME: _____

This Form MUST be completed by the Owner and/or their Electrical Contractor if applicable prior to service connection.

Electric Service Civic Address:_____

Name of Owner:_____

Telephone: _____ **Fax:** _____

Name of Contractor:_____

Telephone: **Fax:**

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

(A) Front View of Electric Meter Base(s)	(B) Billing Address
	1)
	2)
	3)
	4)
	5)
	6)
	7)

The following terms are agreed upon by the undersigned at the time of submitting the form:

1. That all information contained on the 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 the amended form.
4. That an amended form must be signed and returned along with payment of any applicable invoice, as per note 3, prior to further consideration as to the activation of the service connection.

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

Signature of Owner:_____ Date:_____

Signature of Contractor:_____Date:_____

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FINANCIAL STATEMENTS – 2009, 2010 and 2011:

IHDSL's Audited Financial Statements accompany this Schedule as Appendix E.

APPENDIX E

COPIES OF INNISFIL HYDRO DISTRIBUTION SYSTEM LIMITED AUDITED FINANCIAL STATEMENTS FOR 2009, 2010 and 2011

Financial Statements

Innisfil Hydro Distribution Systems Limited

December 31, 2009

Contents

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Auditors' Report	1
Statements of Earnings and Retained Earnings	2
Balance Sheet	3
Statement of Cash Flows	4
Notes to the Financial Statements	5-17

Grant Thornton

Auditors' Report

Grant Thornton LLP
Unit 201
85 Bayfield Street
Barrie, ON
L4M 3A7

T (705) 730-6574
F (705) 730-6575
www.GrantThornton.ca

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, 2009 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 finanoial 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, 2009 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
March 17, 2010

Chartered Accountants
Licensed Public Accountants

Audit • Tax • Advisory
Grant Thornton LLP. A Canadian Member of Grant Thornton International Ltd

Innisfil Hydro Distribution Systems Limited
Statements of Earnings and Retained Earnings

Year Ended December 31	2009	2008
Revenue		
Sale of power	$ 18,877,110	$ 17,244,342
Distribution	7,291,917	6,677,073
	26,169,027	23,921,415
Cost of power		
Power purchased	18,877,110	17,244,342
Distribution revenue	7,291,917	6,677,073
Other revenue (Note 15)	516,463	581,263
Expenses		
Distribution	1,239,020	1,286,723
Billing and collecting	970,446	927,231
Administration	1,518,992	1,368,844
Amortization	1,849,152	1,758,166
	5,577,610	5,340,964
Earnings from operations	2,230,770	1,917,372
Interest on long term debt	537,961	662,711
Earnings before payments in lieu of taxes	1,692,809	1,254,661
Payments in lieu of taxes (Note 17)	460,756	399,640
Net earnings	$ 1,232,053	$ 855,021
Retained earnings, beginning of year	$ 3,359,561	$ 2,036,540
Net earnings	1,232,053	855,021
Dividends	(625,000)	(625,000)
Change in accounting policy	-	1,093,000
Retained earnings, end of year	$ 3,966,614	$ 3,359,561

See accompanying notes to the financial statements.

Innisfil Hydro Distribution Systems Limited
Balance Sheet

December 31	2009	2008
Assets		
Current		
Cash and cash equivalents	$ -	$ 2,844,292
Receivables	2,469,017	1,822,940
Unbilled revenue	3,143,897	2,591,920
Inventory	321,224	322,592
Due from related party (Note 5)	12,300	-
Prepaids	214,903	173,328
	6,161,341	7,755,072
Property and equipment (Note 6)	19,078,750	16,837,829
Intangible assets (Note 7)	632,127	619,891
Long term investment (Note 8)	14,481	7,240
Regulatory assets (Note 9)	2,797,920	1,095,572
Future income taxes (Note 17)	1,731,000	1,516,000
	$ 30,415,619	$ 27,831,604
Liabilities		
Current		
Bank indebtedness (Note 10)	$ 2,334,506	$ -
Payables and accruals	3,858,576	3,454,866
Customer credit balances and deposits	608,554	626,218
Payments in lieu of taxes payable	123,730	164,992
Due to related party (Note 5)	122,655	141,842
Current portion of long-term debt (Notes 5 and 11)	2,757,444	589,000
Future income tax (Note 17)	311,000	318,000
	10,116,465	5,294,918
Customer and retailer deposits	505,875	598,281
Regulatory liabilities (Note 9)	36,601	31,336
Long term debt (Notes 5 and 11)	4,382,000	7,139,444
	15,040,941	13,063,979
Shareholder's Equity		
Capital stock (Note 12)	10,852,444	10,852,444
Development charges transferred to equity	555,620	555,620
Retained earnings	3,966,614	3,359,561
	15,374,678	14,767,625
	$ 30,415,619	$ 27,831,604

Commitment and Contingent liabilities (Notes 13 and 14)

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	2009	2008
Increase (decrease) in cash and cash equivalents		
Operating		
Net earnings	$ 1,232,053	$ 855,021
Gain on disposal	(36,590)	-
Amortization	1,849,152	1,758,166
Future income taxes (Note 17)	(222,000)	(105,000)
	2,822,615	2,508,187
Change in non-cash operating working capital (Note 18)	(1,017,370)	1,068,934
	1,805,245	3,577,121
Financing		
Dividends	(625,000)	(625,000)
Repayment of long term debt	(589,000)	(534,000)
	(1,214,000)	(1,159,000)
Investing		
Net additions to property and equipment, and intangibles	(4,312,278)	(2,146,685)
Proceeds on disposition of property and equipment	44,851	-
Net additions to long term investments	(7,241)	-
Net additions (reduction) to regulatory liabilities	5,265	(158,136)
Net (additions) reduction to regulatory assets	(1,500,640)	21,660
	(5,770,043)	(2,283,161)
Net (decrease) increase in cash and cash equivalents (bank indebtedness)	(5,178,798)	134,960
Cash and cash equivalents, beginning of year	2,844,292	2,709,332
(Bank indebtedness) cash and cash equivalents, end of year	$ (2,334,506)	$ 2,844,292

See accompanying notes to the financial statements.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2009

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, bank indebtedness, short term investments, (maturity of 3 months or less), 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 revenue for the period based on customer's usage since the last meter-reading date to the end of the period. Unbilled revenue is recognized for customer usage not billed at December 31, 2009.

Other revenue, including miscellaneous service revenues, management fee charged to the affiliate, and miscellaneous non-operating income are recognized as services are rendered. Other revenue, relating to late payment charges and interest revenue are recognized as they are earned and measurable.

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. Costs include all acquisition costs incurred in bringing inventory to its present location and condition. Net realizable value is the estimated selling price in the ordinary cost of business less any applicable selling expenses. The Company classifies rebates received from vendors as a reduction to the cost of inventory. Amount of inventory expensed during the year was $12,541 (2008 $13,552).

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2009

2. Summary of significant accounting policies (Continued)

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, 2009 are disclosed in Note 9.

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 recorded at cost less accumulated amortization.

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

Land rights	50 years
Building and fixtures	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 or intangible assets are sold, the cost of the asset and the related accumulated amortization is removed from the accounts, when identifiable 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 when identifiable from the accounts.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2009

2. Summary of significant accounting policies (Continued)

Property and equipment 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 property and equipment 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 property and equipment.

Some of the Company's assets may have asset retirement obligations. As the Company expects to use the majority of its property and equipment 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.

Intangible Assets

Intangible assets represent computer applications software and land rights. These assets are carried at cost net of accumulated amortization.

Corporate income and capital taxes

The Company uses the liability method of tax allocation for accounting for income. Under the liability method of tax allocation, temporary differences arising from the difference between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax liabilities or assets. Future income tax liabilities or assets are measured using the substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse. A valuation allowance is recognized to the extent the recoverability of future income tax assets is not considered more likely than not.

Under the Electricity Act, 1998, the Company is required to make payments in lieu of corporate taxes to the 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.

Use of estimates

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

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2009

2. Summary of significant accounting policies (Continued)

Financial instruments, hedges, and comprehensive income

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

- Cash and deposits at the Company have been classified as "held for trading". GIC investments included and cash and cash equivalents are classified as "held to maturity". They are initially measured at fair value and the gains and losses resulting from the revaluation at fair value at the end of each period are recognized in net income.

- Receivables are classified under "loans and receivables". They are recorded at cost, which, upon their initial measurement, is equal to their fair value. Subsequent measurements of accounts receivable are recorded at amortized cost which usually corresponds to the amount initially recorded less any allowance for doubtful accounts.

- Payables and accruals, bank indebtedness, due from (to) related parties and long term debt are classified as "other financial liabilities". They are initially measured at fair value and the gains and losses resulting from their subsequent measurement at amortized cost, at the end of each period, are recognized in net income.

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.

3. Change in accounting policies

Intangible assets

Effective January 1, 2009, the Company adopted CICA Handbook Section 3064, Goodwill and Intangible Assets, which replaced CICA Handbook Section 3062, Goodwill and Other Intangible Assets and CICA Handbook Section 3450, Research and Development Costs. The new section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and other intangible assets.

As a result of adopting this new accounting standard, the Company has included an intangible asset policy in Note 2 and reclassified computer applications software and land rights in Note 7, previously classified as property and equipment.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2009

4. Future accounting pronouncements

International Financial Reporting standards

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

5. Related party transactions

	2009	2008
The Company had the following related party transactions:		
Innisfil Energy Services Limited ("IESL") - affiliated company controlled by shareholder		
Services provided	$ 22,793	$ 41,609
The Corporation of The Town of Innisfil ("Town") - shareholder		
Interest on advances	$ 528,806	$ 645,097
Electrical services billed	1,693,203	1,369,565
Professional services billed	9,600	7,523
Dividends paid	625,000	625,000
Municipal taxes	53,618	55,040
Other expenses	70,442	69,450
Proceeds on sale of land	44,851	11,447
Balances outstanding at December 31:		
Due from Innisfil Energy Services Limited	$ 12,300	$ (4,830)
Accrued interest, due to the Town	122,655	137,012
Note and debenture payable to the Town (Note 11)	$ 7,139,444	$ 7,728,444
Dividend payable to the Town, included in payables	$ 156,250	$ 156,250
Due from Town, included in receivables	160,835	127,421
Due to the Town, included in payables	13,252	15,872

During the year, the Company provided financial, management and accounting services to IESL in the amount of $22,793 (2008 - $41,609). 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, $12,300 was due from IESL. (2008-($4,830)).

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2009

5. Related party transactions (Continued)

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 $1,693,203 (2008 - $1,369,565) and professional services in the amount of $9,600 (2008 - $7,521). At the end of the year, $160,835 (2008 - $127,421) was due for these services. During the year, the Company paid municipal taxes of $53,618 (2008 - $55,040) and other expenses of $70,442 (2008 - $69,450) to the Town.

6. Property and equipment

	Cost	Accumulated Amortization	2009 Net Book Value	2008 Net Book Value
Land	$ 474,819	$ -	**$ 474,819**	$ 483,080
Building and fixtures	702,948	215,568	**487,380**	512,161
Distribution station	4,388,086	2,288,782	**2,099,304**	2,150,533
Distribution system	40,482,859	21,164,354	**19,318,505**	16,442,258
System supervisory equipment	1,295,959	620,903	**675,056**	656,914
Other equipment	707,257	482,281	**224,976**	159,864
Computer hardware	807,848	651,374	**156,474**	162,754
Contributions in aid of construction	(5,391,302)	(1,033,538)	**(4,357,764)**	(3,729,735)
	$ 43,468,474	$ 24,389,724	**$ 19,078,750**	$ 16,837,829

The amortization for property and equipment for the year was $1,720,327 (2008 - $1,629,274).

7. Intangible assets

	Cost	Accumulated Amortization	2009 Net Book Value	2008 Net Book Value
Land rights	$ 976,547	$ 527,680	**$ 448,867**	$ 452,629
Computer software	985,064	801,804	**183,260**	167,262
	$ 1,961,611	$ 1,329,484	**$ 632,127**	$ 619,891

The amortization for intangible assets for the year was $128,825 (2008 - $128,892).

8. Long term investment

The long term investment is recorded at cost and consists of 12,067 shares of a private company that mainly provides settlement services to the electric utilities of Ontario.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2009

9. Regulatory assets and liabilities

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

	2009	2008
Regulatory assets		
Regulatory asset recovery account I and II	$ (14,449)	$ (7,858)
Regulatory asset recovery accounts 2009	368,803	-
Retail settlement variance accounts	618,341	983,983
Smart meters	1,763,625	(93,593)
Other	61,600	213,040
Total regulatory assets	$ 2,797,920	$ 1,095,572
Regulatory liabilities		
Other	$ 36,601	$ 31,336

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 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 two year period from May 1, 2006 to April 30, 2008. The RARA II includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest.

In the absence of rate regulation, the net effect on earnings would have increased by $6,591 (2008 - $381,170).

Regulatory asset recovery accounts 2009

On April 26, 2009, the OEB announced its decision regarding the Company's OEB cost assessment, pension contribution, LV variance account, and accrued interest balances accumulated as of December 31, 2007. The OEB ordered that the approved balances be recovered on a straight-line

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2009

9. Regulatory assets and liabilities (Continued)

Regulatory asset recovery accounts 2009 (Continued)

basis over a four year period from May 1, 2009 to April 30, 2013. In the absence of rate regulation, the net effect on earnings would have increased by $56,341 (2008 - $ nil).

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, 2004, 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 asset in its retail settlement variance accounts since January 1, 2005 and anticipates that the OEB will include the net balance of this regulatory account in future rates. In the absence of rate regulation, the net effect on earnings would have increase by $114,949 (2008 – decrease of $115,775).

Smart meters

In support of the Province of Ontario's decision to install smart meters throughout Ontario by 2010, the Company launched its smart meter installation program during the year and replaced approximately 67.7% of the meters as at December 31, 2009.

In connection with its smart meter initiatives, the Corporation has incurred costs amounting to $1,807,319 for the year ended December 31, 2009. At Decomber 31, 2009, smart meter capital expenditures, net of accumulated depreciation, totalling $1,754,627 have been recorded to regulatory assets (2008 -$32,497). These expenditures would otherwise have been recorded as property, plant and equipment under Canadian GAAP for unregulated businesses.

Smart meter amortization expense of $52,693 was deferred which otherwise would have been charged to amortization expense under Canadian GAAP for unregulated businesses (2008 - $ nil).

The smart meter customer revenues collected and stranded meters that were replaced during the year were included in regulatory assets. In the absence of rate regulation, the net effect on earnings would have decreased by $82,394 (2008 - increase of $142,390).

Other regulatory assets and liabilities

These accounts include certain amounts deferred as required by OEB guidelines. In the absence of rate regulation, the net effect on earnings would have decreased by $17,748 (2008 - $86,620).

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2009

10. Bank indebtedness

The Company has a bank letter of credit outstanding for $938,146 (2008 - $938,146), as described in Note 14. The letter of credit bears interest at the prime rate of a Canadian chartered bank less .25% per annum. The Company has bank indebtedness of $2,334,506 outstanding, out of $3,000,000 credit limit, at the end of 2009 (2008 - 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 and bears interest at the prime rate.

11. Long term debt

	2009	2008
Debentures payable to the Town	$ 5,032,000	$ 5,621,000
Note payable to the Town	2,107,444	2,107,444
	7,139,444	7,728,444
Less: current portion	2,757,444	589,000
	$ 4,382,000	$ 7,139,444

The debentures are payable to the Town and bear interest at various rates ranging from 0.55% to 2.45%. 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:

2010	$ 2,757,444
2011	716,000
2012	790,000
2013	871,000
2014	960,000

12. Capital stock

Authorized:

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preference shares.

	2009	2008
Issued:		
1,000 common shares	$ 10,852,444	$10,852,444

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2009

13. Commitment

Smart Meters

The Ontario Government has mandated Smart Meters be installed for customers by 2010. As a result the Company will need to install in excess of 14,000 meters, of which 67% have been installed to date. This will result in a large initial cost, which will be recovered in future rates as the meters are amortized over a 15 year period.

14. 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, 2009, the Company provided prudential support using bank letters of credit of $938,146 (2008 - $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.

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.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2009

14. Contingent liabilities (Continued)

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.

The parties are currently in settlement discussions and an agreement in principle has been reached, subject to review and acceptance by each LDC and final approval by the Court. At this time, management estimates its ultimate liability in this matter at $33,598, which it expects to recover in future rates, thus no impact on the statement of earnings.

15. Other revenue	**2009**	2008
Late payment charges	**$ 105,597**	$ 92,096
Interest	**23,616**	117,820
Pole rentals	**154,992**	148,552
Miscellaneous service revenues	**97,610**	77,399
Management fee charged to affiliate	**62,225**	76,196
Miscellaneous non-operating income	**72,423**	69,200
	$ 516,463	$ 581,263

16. Employee future benefits

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 6.3% to 9.5% of employee contributory earnings, depending upon the level of earnings. As a result, the Company made contributions in 2009 totaling $116,193 for the current service (2008 - $130,631).

Early retirement employee benefits

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. A liability has been setup for $28,828 (2008 – Nil).

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2009

17. 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.

Future taxes

Future income taxes are provided for temporary differences. The significant components of the Company's deductible (taxable) timing differences at year end are as follows:

	2009	2008
Future income tax asset:		
Property and equipment	$ 1,731,000	$ 1,516,000
Future income tax liability:		
Regulatory assets	$ (311,000)	$ (318,000)
Provision for PILS:		
Current	$ 682,756	$ 504,640
Future (recovery)	(222,000)	(105,000)
	$ 460,756	$ 399,640

18. Supplemental cash flow information

	2009	2008
Change in non cash operating working capital		
Receivables	$ (646,077)	$ 159,918
Unbilled	(551,977)	(181,483)
Due from (to) related party	(31,487)	(21,108)
Inventory	1,368	(74,294)
Payment in lieu of taxes	(41,261)	540,778
Prepaids	(41,575)	37,253
Payables and accruals	403,709	412,220
Customer credit balances and deposits	(110,070)	195,650
	$ (1,017,370)	$ 1,068,934
Supplemental cash flow information		
Interest received	$ 23,616	$ 102,359
Interest paid	$ 574,476	$ 697,365
Payments in lieu of taxes paid	$ 724,018	$ (30,982)

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2009

19. 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 $24,000,000 per occurrence.

20. Capital disclosures

The Company's objectives when managing capital are:

- to safeguard the entity's ability to continue as a going concern, so that it can continue to provide returns for shareholders and benefits for other stakeholders, and
- to provide an adequate return to shareholders commensurately with the level of risk.

The Company sets the amount of capital in proportion to risk. The Company manages the capital structure and makes adjustments to it in the light of changes in economic conditions and the risk characteristics of the underlying assets. In order to maintain or adjust the capital structure, the Company may adjust the amount of dividends paid to shareholders or return capital to shareholders, issue new shares, or sell assets to reduce debt. The Company is subject to quarterly reporting and bank review of its minimum interest coverage ratio of 2 to1, and maximum debt to capitalization ratio of .6 to 1, in relation to the bank indebtedness.

Consistent with others in the industry, the Company monitors capital on the basis of the debt-to-equity ratio. This ratio is calculated as short and long term debt divided by equity. Short term debt is calculated as current notes and loans payable, as shown on the balance sheet. Long term debt is calculated as total long term debt, as shown on the balance sheet. Equity comprises all components of equity, the share capital, development charges transferred to equity, and retained earnings.

Financial Statements

Innisfil Hydro Distribution Systems Limited

December 31, 2010

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Grant Thornton

Independent Auditors' Report

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To the Directors of

Innisfil Hydro Distribution Systems Limited

We have audited the accompanying financial statements of Innisfil Hydro Distribution Systems Limited, which comprise the balance sheet as at December 31, 2010, and the statement of earnings and retained earnings and cash flow statement for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
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 comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of Innisfil Hydro Distribution Systems Limited as at December 31, 2010, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Grant Thornton LLP

Orillia, Canada
April 18, 2011

Chartered Accountants
Licensed Public Accountants

Innisfil Hydro Distribution Systems Limited
Statements of Earnings and Retained Earnings

Year Ended December 31	2010	2009
Revenue		
Sale of power	$ 20,393,170	$ 18,877,110
Distribution	7,552,968	7,291,917
	27,946,138	26,169,027
Cost of power		
Power purchased	20,393,170	18,877,110
Distribution revenue	7,552,968	7,291,917
Other revenue (Note 14)	438,303	516,463
Expenses		
Distribution	1,306,362	1,239,020
Billing and collecting	922,743	970,446
Administration	1,702,947	1,518,992
Amortization (Note 20)	1,965,295	1,849,152
	5,897,347	5,577,610
Earnings from operations	2,093,924	2,230,770
Interest on long term debt	546,512	537,961
Earnings before payments in lieu of taxes	1,547,412	1,692,809
Payments in lieu of taxes (Note 16)	627,000	460,756
Net earnings	$ 920,412	$ 1,232,053
Retained earnings, beginning of year	$ 3,966,614	$ 3,359,561
Net earnings	920,412	1,232,053
Dividends	(625,000)	(625,000)
Retained earnings, end of year	$ 4,262,026	$ 3,966,614

See accompanying notes to the financial statements.

Innisfil Hydro Distribution Systems Limited
Balance Sheet

December 31	2010	2009
Assets		
Current		
Receivables	**3,857,377**	2,469,017
Unbilled revenue	**3,452,867**	3,143,897
Inventory	**427,866**	321,224
Due from related party (Note 4)	**-**	12,300
Prepaids	**303,127**	214,903
	8,041,237	6,161,341
Property and equipment (Note 5)	**22,026,687**	19,078,750
Intangible assets (Note 6)	**574,068**	632,127
Long term investment (Note 7)	**21,721**	14,481
Regulatory assets (Note 8)	**2,967,878**	2,797,920
Future income taxes (Note 16)	**1,635,000**	1,731,000
	$ 35,266,591	$ 30,415,619
Liabilities		
Current		
Bank Indebtedness (Note 9)	**$ 3,525,117**	$ 2,334,506
Payables and accruals	**5,151,331**	3,858,576
Construction loan (Note 10)	**2,500,000**	-
Customer credit balances and deposits	**564,982**	608,554
Payments in lieu of taxes payable	**109,604**	123,730
Due to related party (Note 4)	**106,949**	122,655
Current portion of long-term debt (Note 11)	**785,000**	2,757,444
Future income tax (Note 16)	**17,000**	311,000
	12,759,983	10,116,465
Customer and retailer deposits	**351,008**	505,875
Regulatory liabilities (Note 8)	**791,866**	36,601
Long term debt (Note 11)	**5,693,644**	4,382,000
	19,596,501	15,040,941
Shareholder's Equity		
Capital stock (Note 12)	**10,852,444**	10,852,444
Development charges transferred to equity	**555,620**	555,620
Retained earnings	**4,262,026**	3,966,614
	15,670,090	15,374,678
	$ 35,266,591	$ 30,415,619

Contingent liabilities (Note13)

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	2010	2009
Increase (decrease) in cash and cash equivalents		
Operating		
Net earnings	**$ 920,412**	$ 1,232,053
Gain on disposal	**-**	(36,590)
Amortization (Note 20)	**2,055,950**	1,849,152
Future income taxes (Note 16)	**(198,000)**	(222,000)
	2,778,362	2,822,615
Change in non-cash operating working capital (Note 17)	**(815,412)**	(1,017,370)
	1,962,950	1,805,245
Financing		
Dividends	**(625,000)**	(625,000)
Advance of construction loan	**2,500,000**	-
Advances of long term debt	**2,107,444**	-
Repayment of long term debt	**(2,768,244)**	(589,000)
	1,214,200	(1,214,000)
Investing		
Net additions to property and equipment, and intangibles	**(4,945,828)**	(4,312,278)
Proceeds on disposition of property and equipment	**-**	44,851
Net additions to long term investments	**(7,240)**	(7,241)
Net reduction (additions) to regulatory assets and liabilities	**585,307**	(1,495,375)
	(4,367,761)	(5,770,043)
Net decrease in cash and cash equivalents	**(1,190,611)**	(5,178,798)
Cash and cash equivalents, beginning of year	**(2,334,506)**	2,844,292
Cash and cash equivalents, end of year	**$ (3,525,117)**	$ (2,334,506)

See accompanying notes to the financial statements.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2010

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, bank indebtedness, short term investments, (maturity of 3 months or less), 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 revenue for the period based on customer's usage since the last meter-reading date to the end of the period. Unbilled revenue is recognized for customer usage not billed at December 31, 2010.

Other revenue, including miscellaneous service revenues and miscellaneous non-operating income are recognized as services are rendered. Other revenue, relating to late payment charges, pole rentals and interest revenue are recognized as they are earned and measurable.

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. Costs include all acquisition costs incurred in bringing inventory to its present location and condition. Net realizable value is the estimated selling price in the ordinary cost of business less any applicable selling expenses. The Company classifies rebates received from vendors as a reduction to the cost of inventory. Amount of inventory expensed during the year was $16,408 (2009 $12,541).

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2010

2. Summary of significant accounting policies (Continued)

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, 2010 are disclosed in Note 8.

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 recorded at cost less accumulated amortization.

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

Land rights	50 years
Building and fixtures	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 or intangible assets are sold, the cost of the asset and the related accumulated amortization is removed from the accounts, when identifiable 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 when identifiable from the accounts.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2010

2. Summary of significant accounting policies (Continued)

Property and equipment 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 property and equipment 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 property and equipment.

Some of the Company's assets may have asset retirement obligations. As the Company expects to use the majority of its property and equipment 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.

Intangible assets

Intangible assets represent computer applications software and land rights. These assets are carried at cost net of accumulated amortization.

Corporate income and capital taxes

The Company uses the liability method of tax allocation for accounting for income. Under the liability method of tax allocation, temporary differences arising from the difference between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax liabilities or assets. Future income tax liabilities or assets are measured using the substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse. A valuation allowance is recognized to the extent the recoverability of future income tax assets is not considered more likely than not.

Under the Electricity Act, 1998, the Company is required to make payments in lieu of corporate taxes to the 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.

Use of estimates

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

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2010

2. Summary of significant accounting policies (Continued)

Financial instruments, hedges, and comprehensive income

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

- Cash and deposits at the Company have been classified as "held for trading". GIC investments included and cash and cash equivalents are classified as "held to maturity". They are initially measured at fair value and the gains and losses resulting from the revaluation at fair value at the end of each period are recognized in net income.

- Receivables are classified under "loans and receivables". They are recorded at cost, which, upon their initial measurement, is equal to their fair value. Subsequent measurements of receivables are recorded at amortized cost which usually corresponds to the amount initially recorded less any allowance for doubtful accounts.

- Payables and accruals, bank indebtedness and long term debt are classified as "other financial liabilities". They are initially measured at fair value and the gains and losses resulting from their subsequent measurement at amortized cost, at the end of each period, are recognized in net income.

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 Company's cash is held at a major institution. The long term debt has fixed interest rates. The bank indebtedness has interest at a floating rate which gives rise to a risk that its income (loss) and cash flows may be adversely affected by changes to interest rates. The Company manages its liquidity risk to ensure access to sufficient funds meet their needs. The fair value of these financial instruments approximates their carrying values, unless otherwise noted.

3. Future accounting pronouncements

International Financial Reporting standards

The CICA has announced that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. The Canadian Accounting Standards Board (AcSB) subsequently released a ruling that qualifying entities with rate-regulated activities have the option to defer their adoption of IFRS until annual periods beginning on or after January 1, 2012. The Company has elected the deferral option.

The Company is currently in the process of evaluating the potential impact of IFRS to the financial statements. This will be an ongoing process. The financial statements as disclosed under current GAAP may be significantly different when presented in accordance with IFRS.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2010

4. Related party transactions	2010	2009
The Company had the following related party transactions:		
Innisfil Energy Services Limited ("IESL") - affiliated company controlled by shareholder		
Services billed	**$ 5,258**	$ 22,793
The Corporation of The Town of Innisfil ("Town") - shareholder		
Interest expensed on advances	**$ 455,574**	$ 528,806
Electrical services billed	**2,017,772**	1,693,203
Professional services billed	**9,600**	9,600
Dividends paid	**625,000**	625,000
Municipal taxes	**55,720**	53,618
Other expenses	**57,859**	70,442
Proceeds on sale of land	**-**	44,851
Contributed capital work billed	**2,482,667**	-
Balances outstanding at December 31:		
Due from IESL	**$ -**	$ (12,300)
Accrued interest, due to the Town	**106,811**	122,655
Note and debenture payable to the Town (Note 11)	**4,382,000**	7,139,444
Dividend payable to the Town, included in payables	**156,250**	156,250
Due from Town, included in receivables	**1,603,800**	160,835
Due to the Town, included in payables	**8,004**	13,252

During the year, the Company provided financial, management and accounting services to IESL in the amount of $5,258 (2009 - $22,793). These transactions have been recorded in these financial statements at the carrying amounts, which were equal to their 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, $138, in payables, was due to 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 $2,017,772 (2009 - $1,693,203), professional services in the amount of $9,600 (2009 - $9,600) and contributed capital of $2,482,667 (2009 nil). At the end of the year, $1,603,800 (2009 - $160,835) was due for these services. During the year, the Company paid municipal taxes of $55,720 (2009 - $53,618) and other expenses of $57,859 (2009 - $70,442) to the Town.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2010

5. Property and equipment

	Cost	Accumulated Amortization	2010 Net Book Value	2009 Net Book Value
Land	$ 474,819	$ -	**$ 474,819**	$ 474,819
Building and fixtures	737,784	244,363	**493,421**	487,380
Distribution station	4,431,283	2,413,304	**2,017,979**	2,099,304
Distribution system	45,833,126	22,698,751	**23,134,375**	19,318,505
System supervisory equipment	1,348,596	709,758	**638,838**	675,056
Other equipment	1,630,818	607,206	**1,023,612**	224,976
Computer hardware	872,058	714,467	**157,591**	156,474
Contributions in aid of construction	(7,193,540)	(1,279,592)	**(5,913,948)**	(4,357,764)
	$ 48,134,944	$ 26,108,257	**$ 22,026,687**	$ 19,078,750

The amortization for property and equipment for the year was $1,910,415 (2009 - $1,720,327).

6. Intangible assets

	Cost	Accumulated Amortization	2010 Net Book Value	2009 Net Book Value
Land rights	$ 988,463	$ 542,810	**$ 445,653**	$ 448,867
Computer software	1,032,750	904,335	**128,415**	183,260
	$ 2,021,213	$ 1,447,145	**$ 574,068**	$ 632,127

The amortization for intangible assets for the year was $117,661 (2009 - $128,825).

7. Long term investment

The long term investment is recorded at cost and consists of 16,894 preferred shares of a private company that mainly provides settlement services to the electric utilities of Ontario.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2010

8. Regulatory assets and liabilities

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

	2010	2009
Regulatory assets		
Regulatory assets approved for recovery	$ 494,780	$ 354,354
Retail settlement variance accounts	-	618,341
Smart meters	2,222,386	1,763,625
Other	250,712	61,600
	$ 2,967,878	$ 2,797,920
Regulatory liabilities		
Other	$ 58,248	$ 36,601
Retail settlement variance accounts	733,618	-
	$ 791,866	$ 36,601

Regulatory asssets approved for recovery

On April 8, 2010, the OEB issued a decision on the disposition of Group I (RARA I and RARA II) regulatory asset recovery accounts into the regulatory asset recovery accounts 2010. In this decision the OEB approved the Group I accounts to be disposed of at the December 31, 2008 value including a projected interest amount up until April 30, 2010.

The OEB ordered the disposition of the Group I account balances over a one eyar period through the rates. All Group I accounts were transferred to the regulatory asset recovery 2010 accounts by June 30, 2010.

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. The RARA II includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest.

On April 26, 2009, the OEB announced its decision regarding the Company's OEB cost assessment, pension contribution, LV variance account, and accrued interest balances accumulated as of December 31, 2007. The OEB ordered that the approved balances be recovered on a straight-line basis over a four year period from May 1, 2009 to April 30, 2013. In the absence of rate regulation, the net effect on earnings would have increased by $140,426 (2009 - $62,932).

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2010

8. Regulatory assets and liabilities (Continued)

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*. To date amounts up to December 31, 2008 have been approved for recovery.

The Company has accumulated a net liability since this time. In the absence of rate regulation, the net effect on earnings would have increase by $733,617 (2009 – $114,949).

Smart meters

In support of the Province of Ontario's decision to install smart meters throughout Ontario by 2010, the Company launched its smart meter installation program during the year and replaced approximately 100% of the meters as at December 31, 2010.

In connection with its smart meter initiatives, the Corporation has incurred costs amounting to $1,975,232 for the year ended December 31, 2010. These expenditures would otherwise have been recorded as property, plant and equipment under Canadian GAAP for unregulated businesses.

Smart meter amortization expense of $101,425 was deferred which otherwise would have been charged to amortization expense under Canadian GAAP for unregulated businesses (2009 - $52,693).

The smart meter customer revenues collected, stranded meters and other expenses were included in regulatory assets. In the absence of rate regulation, the net effect on earnings would have decreased by $136,730 (2009 - decrease of $82,394).

Other regulatory assets and liabilities

These accounts include certain amounts deferred as required by OEB guidelines, including costs incurred to date for compliance with international financial reporting starndards (IFRS). In the absence of rate regulation, the net effect on earnings would have decreased by $167,465 (2009 - $17,748).

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2010

9. Bank indebtedness

The Company has a bank letter of credit outstanding for $938,146 (2009 - $938,146), as described in Note 13. The letter of credit bears interest at the prime rate of a Canadian chartered bank less .25% per annum.

The Company has bank indebtedness of $3,525,117 (2009 - $2,334,506), out of $5,000,000 credit limit, plus additional bulge until January 31, 2011 of $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 and bears interest at the prime rate.

10. Construction Loan

The Company has short term indebtedness with Infrastructure Ontario of $2,500,000 (2009 – nil). The short term debt bears a floating interest rate, based on costs of borrowing in capital markets, with no fixed term of repayment.

11. Long term debt

	2010	2009
Debentures payable to the Town	**$ 4,382,000**	$ 5,032,000
Term loan	**2,096,644**	-
Note payable to the Town	**-**	2,107,444
	6,478,644	7,139,444
Less: current portion	**785,000**	2,757,444
	$ 5,693,644	$ 4,382,000

The debentures are payable to the Town and bear interest at various rates ranging from 0.55% to 1.47%. Principal payments are due annually on March 31 until 2015.

The term loan, due October 2030, is at a fixed interest rate of 4.53% until October 2020 and is secured by a general security agreement conveying first fixed and floating charges over the property, assets, rights and interests of the Company.

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

2011	$ 785,000
2012	862,000
2013	946,000
2014	1,039,000
2015	1,131,000

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2010

12. Capital stock	2010	2009
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

13. 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, 2010, the Company provided prudential support using bank letters of credit of $938,146 (2009 - $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.

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.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2010

13. Contingent liabilities (Continued)

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.

The Company has reviewed and accepted the settlement agreement which has since been approved by the Court. At this time, management's ultimate liability in this matter is $33,598. The payment of the settlement is to be made by June 2011 and it is expected by management to be recovered in future rates, thus no impact on the statement of earnings. This amount has not been accrued in the financial statements.

14. Other revenue	**2010**	2009
Late payment charges	**$ 111,120**	$ 105,597
Interest	**36,839**	23,616
Pole rentals	**161,381**	154,992
Miscellaneous service revenues	**98,671**	97,610
Miscellaneous non-operating income	**30,292**	134,648
	$ 438,303	$ 516,463

15. Employee future benefits

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 6.4% to 9.7% of employee contributory earnings, depending upon the level of earnings. As a result, the Company made contributions in 2010 totalling $139,572 for the current service (2009 - $116,193).

Early retirement employee benefits

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. A liability has been setup for $32,383 (2009 – $28,828).

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2010

16. 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.

Future taxes

Future income taxes are provided for temporary differences. The significant components of the Company's deductible (taxable) timing differences at year end are as follows:

	2010	2009
Future income tax asset:		
Property and equipment and intangibles	$ 1,635,000	$ 1,731,000
Future income tax liability:		
Regulatory assets	$ (17,000)	$ (311,000)
Provision for PILS:		
Current	$ 825,000	$ 682,756
Future (recovery)	(198,000)	(222,000)
	$ 627,000	$ 460,756

17. Supplemental cash flow information

	2010	2009
Change in non cash operating working capital		
Receivables	$ (1,388,360)	$ (646,077)
Unbilled	(308,970)	(551,977)
Due from (to) related party	(3,406)	(31,487)
Inventory	(106,642)	1,368
Payment in lieu of taxes	(14,126)	(41,261)
Prepaids	(88,224)	(41,575)
Payables and accruals	1,292,755	403,709
Customer credit balances and deposits	(198,439)	(110,070)
	$ (815,412)	$ (1,017,370)
Supplemental cash flow information		
Interest received	$ 36,839	$ 23,616
Interest paid	$ 562,218	$ 574,476
Payments in lieu of taxes paid	$ 828,379	$ 724,018

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2010

18. 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 $24,000,000 per occurrence.

19. Capital disclosures

The Company's objectives when managing capital are:

- to safeguard the entity's ability to continue as a going concern, so that it can continue to provide returns for shareholders and benefits for other stakeholders, and
- to provide an adequate return to shareholders commensurately with the level of risk.

The Company sets the amount of capital in proportion to risk. The Company manages the capital structure and makes adjustments to it in the light of changes in economic conditions and the risk characteristics of the underlying assets. In order to maintain or adjust the capital structure, the Company may adjust the amount of dividends paid to shareholders or return capital to shareholders, issue new shares, or sell assets to reduce debt. The Company is subject to quarterly reporting and bank review of its minimum interest coverage ratio of 1.2 to 1, and maximum debt to capitalization ratio of .6 to 1, in relation to the bank indebtedness.

Consistent with others in the industry, the Company monitors capital on the basis of the debt-to-equity ratio. This ratio is calculated as short and long term debt divided by equity. Short term debt is calculated as current notes and loans payable, as shown on the balance sheet. Long term debt is calculated as total long term debt, as shown on the balance sheet. Equity comprises all components of equity, share capital, development charges transferred to equity, and retained earnings.

20. Amortization of property and equipment

The amortization of property and equipment amounted to $2,055,950 (2009 - $1,849,152). The statement of earnings reflects $1,965,295 (2009 - $1,849,152) because the transportation and communication equipment amortization has been allocated to operations where the equipment was used. Amortization of $54,597 (2009 - nil) was mainly recorded as distribution expenses and $36,058 (2009 – nil) was recorded as capital expenditures and capitalized in property and equipment.

Financial Statements

Innisfil Hydro Distribution Systems Limited

December 31, 2011

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Grant Thornton

Independent Auditor's Report

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To the Directors of

Innisfil Hydro Distribution Systems Limited

We have audited the accompanying financial statements of Innisfil Hydro Distribution Systems Limited, which comprise the balance sheet as at December 31, 2011, and the statement of earnings and retained earnings and cash flow statement for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

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 comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Innisfil Hydro Distribution Systems Limited as at December 31, 2011, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Grant Thornton LLP

Orillia, Canada
April 16, 2012

Chartered Accountants
Licensed Public Accountants

Innisfil Hydro Distribution Systems Limited
Statements of Earnings and Retained Earnings

Year Ended December 31	2011	2010
Revenue		
Sale of power	$ 21,570,056	$ 20,393,170
Distribution	7,633,883	7,552,968
	29,203,939	27,946,138
Cost of power		
Power purchased	21,570,056	20,393,170
Distribution revenue	7,633,883	7,552,968
Other revenue (Note 14)	544,272	438,303
Expenses		
Distribution	1,476,314	1,306,362
Billing and collecting	925,296	922,743
Administration	1,806,007	1,702,947
Amortization (Note 20)	1,894,236	1,965,295
	6,101,853	5,897,347
Earnings from operations	2,076,302	2,093,924
Interest on long term debt	672,042	546,512
Earnings before payments in lieu of taxes	1,404,260	1,547,412
Payments in lieu of taxes (Note 16)	293,400	627,000
Net earnings	$ 1,110,860	$ 920,412
Retained earnings, beginning of year	$ 4,262,026	$ 3,966,614
Net earnings	1,110,860	920,412
Dividends	(625,000)	(625,000)
Retained earnings, end of year	$ 4,747,886	$ 4,262,026

See accompanying notes to the financial statements.

Innisfil Hydro Distribution Systems Limited
Balance Sheet

December 31	2011	2010
Assets		
Current		
Receivables	$ 2,952,862	$ 3,857,377
Unbilled revenue	2,914,972	3,452,867
Inventory	428,004	427,866
Payments in lieu of taxes receivable	421,969	-
Prepaids	300,372	303,127
Future income tax (Note 16)	22,000	-
	7,040,179	8,041,237
Property and equipment (Note 5)	23,786,563	22,105,514
Intangible assets (Note 6)	543,912	574,068
Long term investment (Note 7)	21,721	21,721
Regulatory assets (Note 8)	2,563,948	2,889,051
Future income taxes (Note 16)	1,740,000	1,635,000
	$ 35,696,323	$ 35,266,591
Liabilities		
Current		
Bank Indebtedness (Note 9)	$ 1,037,015	$ 3,525,117
Payables and accruals	4,372,280	5,151,331
Short term debt (Note 10)	4,000,000	2,500,000
Customer credit balances and deposits	648,368	564,982
Payments in lieu of taxes payable	-	109,604
Due to related party (Note 4)	97,871	106,949
Current portion of long-term debt (Note 11)	1,026,314	785,000
Future income tax (Note 16)	-	17,000
	11,181,848	12,759,983
Customer and retailer deposits	205,196	351,008
Regulatory liabilities (Note 8)	983,818	791,866
Long term debt (Note 11)	7,169,511	5,693,644
	19,540,373	19,596,501
Shareholder's Equity		
Capital stock (Note 12)	10,852,444	10,852,444
Development charges transferred to equity	555,620	555,620
Retained earnings	4,747,886	4,262,026
	16,155,950	15,670,090
	$ 35,696,323	$ 35,266,591

Contingent liability (Note13)

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

	2011	2010
Increase (decrease) in cash and cash equivalents		
Operating		
Net earnings	**$ 1,110,860**	$ 920,412
Loss on disposal	**(126,618)**	-
Amortization (Note 20)	**2,081,606**	2,055,950
Future income taxes (Note 16)	**(144,000)**	(198,000)
	2,921,848	2,778,362
Change in non-cash operating working capital (Note 17)	**62,899**	(815,412)
	2,984,747	1,962,950
Financing		
Dividends	**(625,000)**	(625,000)
Advance of short term debt	**4,000,000**	2,500,000
Advances of long term debt	**-**	2,107,444
Repayment of long term debt	**(782,819)**	(2,768,244)
	2,592,181	1,214,200
Investing		
Net additions to property and equipment, and intangibles	**(3,605,881)**	(5,024,655)
Net additions to long term investments	**-**	(7,240)
Net reduction to regulatory assets and liabilities	**517,055**	664,134
	(3,088,826)	(4,367,761)
Net increase (decrease) in cash and cash equivalents	**2,488,102**	(1,190,611)
Cash and cash equivalents, beginning of year	**(3,525,117)**	(2,334,506)
Cash and cash equivalents, end of year	**$ (1,037,015)**	$ (3,525,117)

See accompanying notes to the financial statements.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2011

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, bank indebtedness, short term investments, (maturity of 3 months or less), 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 revenue for the period based on customer's usage since the last meter-reading date to the end of the period. Unbilled revenue is recognized for customer usage not billed at December 31, 2011.

Other revenue, including miscellaneous service revenues and miscellaneous non-operating income are recognized as services are rendered. Other revenue, relating to late payment charges, pole rentals and interest revenue are recognized as they are earned and measurable. Scientific research and development tax credits (SRED) are recognized in other revenue when they have been applied for and are measurable.

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. Costs include all acquisition costs incurred in bringing inventory to its present location and condition. Net realizable value is the estimated selling price in the ordinary cost of business less any applicable selling expenses. The Company classifies rebates received from vendors as a reduction to the cost of inventory. Amount of inventory expensed during the year was $11,747 (2010 - $16,408).

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2011

2. Summary of significant accounting policies (Continued)

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, 2011 are disclosed in Note 8.

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 recorded at cost less accumulated amortization. Property and equipment that is under construction in process (CIP) is not amortized until it is ready for use.

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

Land rights	50 years
Building and fixtures	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 or intangible assets are sold, the cost of the asset and the related accumulated amortization is removed from the accounts, when identifiable 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 when it is identifiable.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2011

2. Summary of significant accounting policies (Continued)

Property and equipment 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 property and equipment 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 property and equipment.

Some of the Company's assets may have asset retirement obligations. As the Company expects to use the majority of its property and equipment 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.

Intangible assets

Intangible assets represent computer applications software and land rights. These assets are carried at cost net of accumulated amortization.

Corporate income and capital taxes

The Company uses the liability method of tax allocation for accounting for income. Under the liability method of tax allocation, temporary differences arising from the difference between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax liabilities or assets. Future income tax liabilities or assets are measured using the substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse. A valuation allowance is recognized to the extent the recoverability of future income tax assets are not considered more likely than not.

Under the Electricity Act, 1998, the Company is required to make payments in lieu of corporate taxes to the 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.

Use of estimates

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

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2011

2. Summary of significant accounting policies (Continued)

Financial instruments, hedges, and comprehensive income

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

- Cash and deposits at the Company have been classified as "held for trading". GIC investments included and cash and cash equivalents are classified as "held to maturity". They are initially measured at fair value and the gains and losses resulting from the revaluation at fair value at the end of each period are recognized in net income.

- Receivables are classified under "loans and receivables". They are recorded at cost, which, upon their initial measurement, is equal to their fair value. Subsequent measurements of receivables are recorded at amortized cost which usually corresponds to the amount initially recorded less any allowance for doubtful accounts.

- Payables and accruals, bank indebtedness and long term debt are classified as "other financial liabilities". They are initially measured at fair value and the gains and losses resulting from their subsequent measurement at amortized cost, at the end of each period, are recognized in net income.

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 Company's cash is held at a major institution. The long term debt has fixed interest rates. The bank indebtedness has interest at a floating rate which gives rise to a risk that its income (loss) and cash flows may be adversely affected by changes to interest rates. The Company manages its liquidity risk to ensure access to sufficient funds meet their needs. The fair value of these financial instruments approximates their carrying values, unless otherwise noted.

3. Future accounting pronouncements

International Financial Reporting Standards

The CICA has announced that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. The Canadian Accounting Standards Board (AcSB) subsequently released a ruling that qualifying entities with rate-regulated activities have the option to defer their adoption of IFRS until annual periods beginning on or after January 1, 2013. The Company has elected to adopt IFRS effective January 1, 2012.

IFRS will require increased financial statement disclosure. Although IFRS uses a conceptual framework similar to Canadian generally accepted accounting principles, there will be some differences in accounting policies that will need to be addressed. The Company is currently in the process of implementing its plan for the adoption of IFRS.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2011

4. Related party transactions

	2011	2010
The Company had the following related party transactions:		
Innisfil Energy Services Limited ("IESL") - affiliated company controlled by shareholder		
Services billed	$ **8,652**	$ 5,258
The Corporation of The Town of Innisfil ("Town") - shareholder		
Interest expensed on debentures	$ **374,888**	$ 455,574
Electrical services billed	**2,123,914**	1,862,558
Professional services billed	**-**	9,600
Dividends paid	**625,000**	625,000
Municipal taxes	**54,061**	55,720
Other expenses	**81,883**	57,859
Contributed capital work billed	**857,783**	2,482,667
Balances outstanding at December 31:		
Due to IESL	$ **8,512**	$ -
Accrued interest, due to the Town	**89,359**	106,811
Note and debenture payable to the Town (Note 11)	**3,666,000**	4,382,000
Dividend payable to the Town, included in payables	**312,500**	156,250
Due from the Town, included in receivables	**322,075**	1,603,800
Due to the Town, included in payables	**7,372**	8,004

During the year, the Company provided financial, management and accounting services to IESL in the amount of $8,652 (2010 - $5,258). These transactions have been recorded in these financial statements at the carrying amounts, which were equal to their 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, $8,512, in payables, was due to 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 $2,400,023 (2010 - $2,017,772), professional services in the amount of $nil (2010 - $9,600) and contributed capital of $857,783 (2010 - $2,482,667). At the end of the year, $322,075 (2010 - $1,603,800) was due for these services. During the year, the Company paid municipal taxes $54,061 (2010 - $55,720) and other expenses of $81,883 (2010 - $57,859) to the Town.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2011

5. Property and equipment

	Cost	Accumulated Amortization	2011 Net Book Value	2010 Net Book Value
Land	$ 474,819	$ -	**$ 474,819**	$ 474,819
Building and fixtures	739,632	273,912	**465,720**	493,421
Distribution station	4,358,561	2,322,875	**2,035,686**	2,017,979
Distribution system	49,028,643	24,039,688	**24,988,955**	23,213,202
System supervisory equipment	1,407,393	789,058	**618,335**	638,838
Other equipment	2,035,356	913,420	**1,121,936**	1,023,612
Computer hardware	515,305	400,081	**115,224**	157,591
CIP	110,616	-	**110,616**	-
Contributions in aid of construction	(7,714,947)	(1,570,219)	**(6,144,728)**	(5,913,948)
	$ 50,955,378	$ 27,168,815	**$ 23,786,563**	$ 22,105,514

The amortization for property and equipment for the year was $1,984,467 (2010 - $1,938,289).

6. Intangible assets

	Cost	Accumulated Amortization	2011 Net Book Value	2010 Net Book Value
Land rights	$ 982,703	$ 557,986	**$ 424,717**	$ 445,653
Computer software	331,066	211,871	**119,195**	128,415
	$ 1,313,769	$ 769,857	**$ 543,912**	$ 574,068

The amortization for intangible assets for the year was $97,139 (2010 - $117,661).

7. Long term investment

The long term investment is recorded at cost and consists of 16,894 preferred shares of a private company that mainly provides settlement services to the electric utilities of Ontario.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2011

8. Regulatory assets and liabilities

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

	2011	2010
Regulatory assets		
Regulatory assets approved for recovery	$ (8,150)	$ 494,780
Smart meters	2,153,227	2,143,559
Other	418,871	250,712
	$ 2,563,948	$ 2,889,051
Regulatory liabilities		
Other	$ 96,899	$ 58,248
Retail settlement variance accounts	886,919	733,618
	$ 983,818	$ 791,866

Regulatory assets approved for recovery

On March 28, 2011, the OEB issued a decision on the disposition of Group I (RARA I and RARA II) regulatory asset recovery accounts into the regulatory asset recovery accounts 2010. In this decision the OEB approved the Group I accounts to be disposed of at the December 31, 2009 value including a projected interest amount up until April 30, 2011.

The OEB ordered the disposition of the Group I account balances over a one year period through the rates. All Group I accounts were transferred to the regulatory asset recovery 2011 accounts by June 30, 2011.

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. The RARA II includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest.

On April 26, 2009, the OEB announced its decision regarding the Company's OEB cost assessment, pension contribution, LV variance account, and accrued interest balances accumulated as of December 31, 2007. The OEB ordered that the approved balances be recovered on a straight-line basis over a four year period from May 1, 2009 to April 30, 2013. In the absence of rate regulation, the net effect on earnings would have increased by $502,931 (2010 – decrease of $140,426).

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2011

8. Regulatory assets and liabilities (Continued)

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*. To date amounts up to December 31, 2010 have been approved for recovery.

The Company has accumulated a net liability since this time. In the absence of rate regulation, the net effect on earnings would have increase by $153,301 (2010 – $1,351,961).

Smart meters

In support of the Province of Ontario's decision to install smart meters throughout Ontario by 2010, the Company launched its smart meter installation program during the year and replaced approximately 100% of the meters as at December 31, 2010.

In connection with its smart meter initiatives, the Corporation has incurred costs amounting to $2,151,271 for the year ended December 31, 2011 (2010 - $1,975,232). These expenditures would otherwise have been recorded as property, plant and equipment under Canadian GAAP for unregulated businesses.

Smart meter amortization expense of $189,061 was deferred which otherwise would have been charged to amortization expense under Canadian GAAP for unregulated businesses (2010 - $101,425).

The smart meter customer revenues collected, stranded meters and other expenses were included in regulatory assets. In the absence of rate regulation, the net effect on earnings would have increased by $12,252 (2010 - decrease of $57,903).

Other regulatory assets and liabilities

These accounts include certain amounts deferred as required by OEB guidelines, including costs incurred to date for compliance with international financial reporting standards (IFRS) of $289,466 (2010 - $108,487). In the absence of rate regulation, the net effect on earnings would have decreased by $129,509 (2010 - $167,465).

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2011

9. Bank indebtedness

The Company has a bank letter of credit outstanding for $938,146 (2010 - $938,146), as described in Note 13. The letter of credit bears interest at the prime rate of a Canadian chartered bank less .25% per annum.

The Company has bank indebtedness of $1,037,015 (2010 - $3,525,117), out of $4,000,000 credit limit. 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 and bears interest at the prime rate.

10. Short term debt

The Company has short term indebtedness with Toronto Dominion Bank of $4,000,000 (2010 – 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. The facility also bears interest at the prime rate, with no fixed term of repayment.

11. Long term debt

	2011	2010
Debentures payable to the Town	$ **3,666,000**	$ 4,382,000
Term loan	**2,029,825**	2,096,644
Infrastructure Ontario Loan	**2,500,000**	-
	8,195,825	6,478,644
Less: current portion	**1,026,314**	785,000
	$ **7,169,511**	$ 5,693,644

The debentures are payable to the Town and bear interest at various rates ranging from 9.5% to 9.75%. Principal payments are due annually on March 31 until 2015.

The term loan, due October 2030, is at a fixed interest rate of 4.53% until October 2020 and is secured by a general security agreement conveying first fixed and floating charges over the property, assets, rights and interests of the Company.

The Infrastructure Ontario Debenture was converted from a construction loan to pay for the Smart Meter Initiative. The long term debt bears interest at 3.91% with semi-annual payments in February and August until 2026.

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

2012	1,026,314
2013	1,110,797
2014	1,203,179
2015	1,291,718
2016	250,198

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2011

12. Capital stock

	2011	2010
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

13. Contingent liability

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, 2011, the Company provided prudential support using bank letters of credit of $938,146 (2010 - $938,146).

14. Other revenue

	2011	2010
Late payment charges	**$ 104,841**	$ 111,120
Interest	**53,329**	36,839
Pole rentals	**157,442**	161,381
Loss on disposal	**(126,618)**	-
SRED revenue	**153,377**	-
Miscellaneous service revenues	**123,934**	98,671
Miscellaneous non-operating income	**77,967**	30,292
	$ 544,272	$ 438,303

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2011

15. Employee future benefits

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 7.4% to 10.7% of employee contributory earnings, depending upon the level of earnings. As a result, the Company made contributions in 2011 totalling $197,301 for the current service (2010 - $139,572).

Early retirement employee benefits

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. A liability has been setup for $36,192 (2010 – $32,383).

16. 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.

Future taxes

Future income taxes are provided for temporary differences. The significant components of the Company's deductible (taxable) timing differences at year end are as follows:

	2011	2010
Future income tax asset:		
Property and equipment and intangibles	**$ 1,740,000**	$ 1,635,000
Future income tax asset (liability):		
Regulatory assets	**$ 22,000**	$ (17,000)
Provision for PILS:		
Current	**$ 437,400**	$ 825,000
Future (recovery)	**(144,000)**	(198,000)
	$ 293,400	$ 627,000

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2011

17. Supplemental cash flow information

	2011	2010
Change in non-cash operating working capital		
Receivables	**$ 904,515**	$ (1,388,360)
Unbilled	**537,895**	(308,970)
Due to related party	**(9,078)**	(3,406)
Inventory	**(138)**	(106,642)
Payment in lieu of taxes	**(531,573)**	(14,126)
Prepaids	**2,755**	(88,224)
Payables and accruals	**(779,051)**	1,292,755
Customer credit balances and deposits	**(62,426)**	(198,439)
	$ 62,899	$ (815,412)
Supplemental cash flow information		
Interest received	**$ 53,329**	$ 36,839
Interest paid	**$ 652,535**	$ 562,218
Payments in lieu of taxes paid	**$ 774,030**	$ 828,379

18. 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 $24,000,000 per occurrence.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2011

19. Capital disclosures

The Company's objectives when managing capital are:

- to safeguard the entity's ability to continue as a going concern, so that it can continue to provide returns for shareholders and benefits for other stakeholders, and
- to provide an adequate return to shareholders commensurately with the level of risk.

The Company sets the amount of capital in proportion to risk. The Company manages the capital structure and makes adjustments to it in the light of changes in economic conditions and the risk characteristics of the underlying assets. In order to maintain or adjust the capital structure, the Company may adjust the amount of dividends paid to shareholders or return capital to shareholders, issue new shares, or sell assets to reduce debt. The Company is subject to quarterly reporting and bank review of its minimum interest coverage ratio of 1.2 to 1, and maximum debt to capitalization ratio of .6 to 1, in relation to the bank indebtedness. The Company is subject to annual from Infrastructure Ontario of its minimum debt service coverage ratio of 1 to 1, a maximum debt to capital ratio of 0.75 to 1, and a minimum current ratio of 1.1 to 1, in relation to the Infrastructure Ontario debenture.

Consistent with others in the industry, the Company monitors capital on the basis of the debt-to-equity ratio. This ratio is calculated as short and long term debt divided by equity. Short term debt is calculated as current notes and loans payable, as shown on the balance sheet. Long term debt is calculated as total long term debt, as shown on the balance sheet. Equity comprises all components of equity, share capital, development charges transferred to equity, and retained earnings.

20. Amortization of property and equipment and intangible assets

The amortization of property and equipment and intangible assets amounted to $2,081,606 (2010 - $2,055,950). The statement of earnings reflects $1,894,236 (2010 - $1,965,295) because the transportation and communication equipment amortization has been allocated to operations where the equipment was used. Amortization of $110,734 (2010 - $54,597) was mainly recorded as distribution expenses and $76,636 (2010 – $36,058) was recorded as capital expenditures and capitalized in property and equipment.

21. Comparative figures

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

RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND REGULATORY ACCOUNTING

No reconciliation is required between the Financial Statements and Regulatory Accounting.

PRO FORMA FINANCIAL STATEMENTS - 2012 AND 2013:

The Pro Forma Statements for the 2012 Bridge Year and the 2013 Test Year accompany this Schedule as Appendix E and Appendix F respectively.

APPENDIX F

COPY OF INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED

2012 PRO FORMA FINANCIAL STATEMENTS - MIFRS

Innisfil Hydro Distribution Systems Limited
, License Number ED-2002-0520, File Number EB-2012-0139

Innisfil Hydro Distribution Systems Limited
2012 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(12,776,613)
4010-Commercial Energy Sales	0
4015-Industrial Energy Sales	0
4020-Energy Sales to Large Users	0
4025-Street Lighting Energy Sales	(125,386)
4030-Sentinel Energy Sales	(9,266)
4035-General Energy Sales	(6,971,967)
4040-Other Energy Sales to Public Authorities	0
4045-Energy Sales to Railroads and Railways	0
4050-Revenue Adjustment	(72,133)
4055-Energy Sales for Resale	0
4060-Interdepartmental Energy Sales	0
4062-WMS	(1,563,933)
4064-Billed WMS-One Time	0
4066-NS	(1,269,763)
4068-CS	(998,898)
4075-LV Charges	(509,104)
3000-Sales of Electricity Total	**(24,297,062)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(8,449,474)
4080-2-SSS Revenue	(54,203)
4082-RS Rev	0
4084-Serv Tx Requests	0
4090-Electric Services Incidental to Energy Sales	0
3050-Revenues From Services - Distirbution Total	**(8,503,677)**
3100-Other Operating Revenues	
4205-Interdepartmental Rents	0
4210-Rent from Electric Property	(162,676)
4215-Other Utility Operating Income	0
4220-Other Electric Revenues	0
4225-Late Payment Charges	(110,402)
4230-Sales of Water and Water Power	0
4235-Miscellaneous Service Revenues	(149,670)
4240-Provision for Rate Refunds	0
4245-Government Assistance Directly Credited to Income	0
3100-Other Operating Revenues Total	**(422,748)**

Account Description	Total
3150-Other Income & Deductions	
4305-Regulatory Debits	639,864
4310-Regulatory Credits	0
4315-Revenues from Electric Plant Leased to Others	0
4320-Expenses of Electric Plant Leased to Others	0
4325-Revenues from Merchandise, Jobbing, Etc.	0
4330-Costs and Expenses of Merchandising, Jobbing, Etc	0
4335-Profits and Losses from Financial Instrument Hedges	0
4340-Profits and Losses from Financial Instrument Investments	0
4345-Gains from Disposition of Future Use Utility Plant	0
4350-Losses from Disposition of Future Use Utility Plant	0
4355-Gain on Disposition of Utility and Other Property	0
4360-Loss on Disposition of Utility and Other Property	51,476
4365-Gains from Disposition of Allowances for Emission	0
4370-Losses from Disposition of Allowances for Emission	0
4375-Revenues from Non-Utility Operations	(384,806)
4380-Expenses of Non-Utility Operations	405,862
4385-Expenses of Non-Utility Operations	0
4390-Miscellaneous Non-Operating Income	(30,009)
4395-Rate-Payer Benefit Including Interest	0
4398-Foreign Exchange Gains and Losses, Including Amortization	0
3150-Other Income & Deductions Total	**682,387**
3200-Investment Income	
4405-Interest and Dividend Income	(64,600)
4415-Equity in Earnings of Subsidiary Companies	0
3200-Investment Income Total	**(64,600)**
3350-Power Supply Expenses	
4705-Power Purchased	19,883,232
4708-WMS	1,290,865
4710-Cost of Power Adjustments	72,133
4712-Charges - One Time	0
4714-NW	1,269,763
4715-System Control and Load Dispatching	0
4716-NCN	998,898
4720-Other Expenses	0
4725-Competition Transition Expense	0
4730-Rural Rate Assistance Expense	273,068
4750-LV Charges	509,104
3350-Power Supply Expenses Total	**24,297,062**

Account Description	Total
3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	188,345
5010-Load Dispatching	10,700
5012-Station Buildings and Fixtures Expense	45,000
5014-Transformer Station Equipment - Operation Labour	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0
5016-Distribution Station Equipment - Operation Labour	6,900
5017-Distribution Station Equipment - Operation Supplies and Expenses	2,800
5020-Overhead Distribution Lines and Feeders - Operation Labour	107,000
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	24,100
5030-Overhead Subtransmission Feeders - Operation	3,700
5035-Overhead Distribution Transformers - Operation	900
5040-Underground Distribution Lines and Feeders - Operation Labour	35,000
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	21,400
5050-Underground Subtransmission Feeders - Operation	0
5055-Underground Distribution Transformers - Operation	0
5060-Street Lighting and Signal System Expense	0
5065-Meter Expense	206,500
5070-Customer Premises - Operation Labour	47,000
5075-Customer Premises - Materials and Expenses	14,250
5085-Miscellaneous Distribution Expense	438,100
5090-Underground Distribution Lines and Feeders - Rental Paid	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	7,500
5096-Other Rent	0
3500-Distribution Expenses - Operation Total	**1,159,195**

Account Description	Total
3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	18,900
5110-Maintenance of Structures	0
5112-Maintenance of Transformer Station Equipment	0
5114-Mtaint Dist Stn Equip	54,600
5120-Maintenance of Poles, Towers and Fixtures	5,550
5125-Maintenance of Overhead Conductors and Devices	72,950
5130-Maintenance of Overhead Services	60,750
5135-Overhead Distribution Lines and Feeders - Right of Way	215,100
5145-Maintenance of Underground Conduit	0
5150-Maintenance of Underground Conductors and Devices	4,750
5155-Maintenance of Underground Services	96,850
5160-Maintenance of Line Transformers	31,650
5165-Maintenance of Street Lighting and Signal Systems	0
5170-Sentinel Lights - Labour	0
5172-Sentinel Lights - Materials and Expenses	0
5175-Maintenance of Meters	40,700
5178-Customer Installations Expenses - Leased Property	0
5195-Maintenance of Other Installations on Customer Premises	0
3550-Distribution Expenses - Maintenance Total	**601,800**
3650-Billing and Collecting	
5305-Supervision	64,900
5310-Meter Reading Expense	33,300
5315-Customer Billing	384,600
5320-Collecting	327,800
5325-Collecting - Cash Over and Short	50
5330-Collection Charges	0
5335-Bad Debt Expense	75,000
5340-Miscellaneous Customer Accounts Expenses	69,850
3650-Billing and Collecting Total	**955,500**
3700-Community Relations	
5405-Supervision	0
5410-Community Relations - Sundry	14,400
5415-Energy Conservation	0
5420-Community Safety Program	1,500
5425-Miscellaneous Customer Service and Informational Expenses	2,500
3700-Community Relations Total	**18,400**

Account Description	Total
3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	227,875
5610-Management Salaries and Expenses	225,025
5615-General Administrative Salaries and Expenses	699,800
5620-Office Supplies and Expenses	94,000
5625-Administrative Expense Transferred-Credit	0
5630-Outside Services Employed	148,500
5635-Property Insurance	59,470
5640-Injuries and Damages	37,000
5645-Employee Pensions and Benefits	4,400
5650-Franchise Requirements	0
5655-Regulatory Expenses	56,000
5660-General Advertising Expenses	0
5665-Miscellaneous Expenses	116,392
5670-Rent	600
5675-Maintenance of General Plant	221,000
5680-Electrical Safety Authority Fees	9,800
5685-Independent Market Operator Fees and Penalties	0
5695-OM&A Contra Account	0
3800-Administrative and General Expenses Total	**1,899,862**
3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	1,422,426
5710-Amortization of Limited Term Electric Plant	0
5715-Amortization of Intangibles and Other Electric Plant	0
5720-Amortization of Electric Plant Acquisition Adjustments	0
5725-Miscellaneous Amortization	0
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	0
5735-Amortization of Deferred Development Costs	0
5740-Amortization of Deferred Charges	0
3850-Amortization Expense Total	**1,422,426**

Account Description	Total
3900-Interest Expense	
6005-Interest on Long Term Debt	93,929
6010-Amortization of Debt Discount and Expense	0
6015-Amortization of Premium on Debt-Credit	0
6020-Amortization of Loss on Reacquired Debt	0
6025-Amortization of Gain on Reacquired Debt-Credit	0
6030-Interest on Debt to Associated Companies	299,700
6035-Other Interest Expense	349,033
6040-Allowance for Borrowed Funds Used During Construction-Credit	0
6042-Allowance for Other Funds Used During Construction	0
6045-Interest Expense on Capital Lease Obligations	0
3900-Interest Expense Total	**742,662**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	12,000
3950-Taxes Other Than Income Taxes Total	**12,000**
4000-Income Taxes	
6110-Income Taxes	418,800
6115-Provision for Future Income Taxes	0
4000-Income Taxes Total	**418,800**
4100-Extraordinary & Other Items	
6205-Donations	1,000
6210-Life Insurance	0
6215-Penalties	0
6225-Other Deductions	0
4100-Extraordinary & Other Items Total	**1,000**
Net Income - (Gain)/Loss	**(1,076,993)**

APPENDIX G

COPY OF INNISFIL HYDRO DISTRIBUTION SYSTEM LIMITED

2013 PRO FORMA STATEMENTS – MIFRS (Existing Rates)

Innisfil Hydro Distribution Systems Limited
, License Number ED-2002-0520, File Number EB-2012-0139

Innisfil Hydro Distribution Systems Limited
2013 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(12,636,265)
4010-Commercial Energy Sales	0
4015-Industrial Energy Sales	0
4020-Energy Sales to Large Users	0
4025-Street Lighting Energy Sales	(127,061)
4030-Sentinel Energy Sales	(8,981)
4035-General Energy Sales	(7,059,467)
4040-Other Energy Sales to Public Authorities	0
4045-Energy Sales to Railroads and Railways	0
4050-Revenue Adjustment	(73,097)
4055-Energy Sales for Resale	0
4060-Interdepartmental Energy Sales	0
4062-WMS	(1,560,041)
4064-Billed WMS-One Time	0
4066-NS	(1,267,081)
4068-CS	(996,766)
4075-LV Charges	(509,329)
3000-Sales of Electricity Total	**(24,238,088)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(8,477,538)
4080-2-SSS Revenue	(55,033)
4082-RS Rev	0
4084-Serv Tx Requests	0
4090-Electric Services Incidental to Energy Sales	0
3050-Revenues From Services - Distirbution Total	**(8,532,571)**
3100-Other Operating Revenues	
4205-Interdepartmental Rents	0
4210-Rent from Electric Property	(167,600)
4215-Other Utility Operating Income	0
4220-Other Electric Revenues	0
4225-Late Payment Charges	(113,700)
4230-Sales of Water and Water Power	0
4235-Miscellaneous Service Revenues	(154,100)
4240-Provision for Rate Refunds	0
4245-Government Assistance Directly Credited to Income	0
3100-Other Operating Revenues Total	**(435,400)**

Account Description	Total
3150-Other Income & Deductions	
4305-Regulatory Debits	0
4310-Regulatory Credits	0
4315-Revenues from Electric Plant Leased to Others	0
4320-Expenses of Electric Plant Leased to Others	0
4325-Revenues from Merchandise, Jobbing, Etc.	0
4330-Costs and Expenses of Merchandising, Jobbing, Etc	0
4335-Profits and Losses from Financial Instrument Hedges	0
4340-Profits and Losses from Financial Instrument Investments	0
4345-Gains from Disposition of Future Use Utility Plant	0
4350-Losses from Disposition of Future Use Utility Plant	0
4355-Gain on Disposition of Utility and Other Property	0
4360-Loss on Disposition of Utility and Other Property	48,825
4365-Gains from Disposition of Allowances for Emission	0
4370-Losses from Disposition of Allowances for Emission	0
4375-Revenues from Non-Utility Operations	(500,668)
4380-Expenses of Non-Utility Operations	469,228
4385-Expenses of Non-Utility Operations	0
4390-Miscellaneous Non-Operating Income	(30,900)
4395-Rate-Payer Benefit Including Interest	0
4398-Foreign Exchange Gains and Losses, Including Amortization	0
3150-Other Income & Deductions Total	**(13,515)**
3200-Investment Income	
4405-Interest and Dividend Income	(53,000)
4415-Equity in Earnings of Subsidiary Companies	0
3200-Investment Income Total	**(53,000)**
3350-Power Supply Expenses	
4705-Power Purchased	19,831,774
4708-WMS	1,287,653
4710-Cost of Power Adjustments	73,097
4712-Charges - One Time	0
4714-NW	1,267,081
4715-System Control and Load Dispatching	0
4716-NCN	996,766
4720-Other Expenses	0
4725-Competition Transition Expense	0
4730-Rural Rate Assistance Expense	272,388
4750-LV Charges	509,329
3350-Power Supply Expenses Total	**24,238,088**

Account Description	Total
3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	199,285
5010-Load Dispatching	11,050
5012-Station Buildings and Fixtures Expense	47,400
5014-Transformer Station Equipment - Operation Labour	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0
5016-Distribution Station Equipment - Operation Labour	7,100
5017-Distribution Station Equipment - Operation Supplies and Expenses	2,900
5020-Overhead Distribution Lines and Feeders - Operation Labour	109,100
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	25,050
5030-Overhead Subtransmission Feeders - Operation	3,850
5035-Overhead Distribution Transformers - Operation	1,000
5040-Underground Distribution Lines and Feeders - Operation Labour	36,100
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	23,650
5050-Underground Subtransmission Feeders - Operation	0
5055-Underground Distribution Transformers - Operation	0
5060-Street Lighting and Signal System Expense	0
5065-Meter Expense	339,849
5070-Customer Premises - Operation Labour	48,400
5075-Customer Premises - Materials and Expenses	14,800
5085-Miscellaneous Distribution Expense	546,628
5090-Underground Distribution Lines and Feeders - Rental Paid	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	7,700
5096-Other Rent	0
3500-Distribution Expenses - Operation Total	**1,423,862**

Account Description	Total
3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	19,550
5110-Maintenance of Structures	0
5112-Maintenance of Transformer Station Equipment	0
5114-Mtaint Dist Stn Equip	56,230
5120-Maintenance of Poles, Towers and Fixtures	19,340
5125-Maintenance of Overhead Conductors and Devices	101,000
5130-Maintenance of Overhead Services	62,650
5135-Overhead Distribution Lines and Feeders - Right of Way	222,650
5145-Maintenance of Underground Conduit	0
5150-Maintenance of Underground Conductors and Devices	5,050
5155-Maintenance of Underground Services	99,850
5160-Maintenance of Line Transformers	82,530
5165-Maintenance of Street Lighting and Signal Systems	0
5170-Sentinel Lights - Labour	0
5172-Sentinel Lights - Materials and Expenses	0
5175-Maintenance of Meters	44,800
5178-Customer Installations Expenses - Leased Property	0
5195-Maintenance of Other Installations on Customer Premises	0
3550-Distribution Expenses - Maintenance Total	**713,650**
3650-Billing and Collecting	
5305-Supervision	66,800
5310-Meter Reading Expense	38,000
5315-Customer Billing	480,600
5320-Collecting	340,820
5325-Collecting - Cash Over and Short	100
5330-Collection Charges	0
5335-Bad Debt Expense	100,000
5340-Miscellaneous Customer Accounts Expenses	79,700
3650-Billing and Collecting Total	**1,106,020**
3700-Community Relations	
5405-Supervision	0
5410-Community Relations - Sundry	19,400
5415-Energy Conservation	0
5420-Community Safety Program	1,500
5425-Miscellaneous Customer Service and Informational Expenses	3,000
3700-Community Relations Total	**23,900**

Account Description	Total
3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	233,375
5610-Management Salaries and Expenses	232,247
5615-General Administrative Salaries and Expenses	849,125
5620-Office Supplies and Expenses	107,000
5625-Administrative Expense Transferred-Credit	0
5630-Outside Services Employed	152,895
5635-Property Insurance	61,254
5640-Injuries and Damages	38,110
5645-Employee Pensions and Benefits	4,500
5650-Franchise Requirements	0
5655-Regulatory Expenses	107,000
5660-General Advertising Expenses	0
5665-Miscellaneous Expenses	114,884
5670-Rent	750
5675-Maintenance of General Plant	286,500
5680-Electrical Safety Authority Fees	10,000
5685-Independent Market Operator Fees and Penalties	0
5695-OM&A Contra Account	0
3800-Administrative and General Expenses Total	**2,197,640**
3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	1,611,954
5710-Amortization of Limited Term Electric Plant	0
5715-Amortization of Intangibles and Other Electric Plant	0
5720-Amortization of Electric Plant Acquisition Adjustments	0
5725-Miscellaneous Amortization	0
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	0
5735-Amortization of Deferred Development Costs	0
5740-Amortization of Deferred Charges	0
3850-Amortization Expense Total	**1,611,954**

Account Description	Total
3900-Interest Expense	
6005-Interest on Long Term Debt	87,502
6010-Amortization of Debt Discount and Expense	0
6015-Amortization of Premium on Debt-Credit	0
6020-Amortization of Loss on Reacquired Debt	0
6025-Amortization of Gain on Reacquired Debt-Credit	0
6030-Interest on Debt to Associated Companies	216,700
6035-Other Interest Expense	764,054
6040-Allowance for Borrowed Funds Used During Construction-Credit	0
6042-Allowance for Other Funds Used During Construction	0
6045-Interest Expense on Capital Lease Obligations	0
3900-Interest Expense Total	**1,068,256**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	12,500
3950-Taxes Other Than Income Taxes Total	**12,500**
4000-Income Taxes	
6110-Income Taxes	227,700
6115-Provision for Future Income Taxes	0
4000-Income Taxes Total	**227,700**
4100-Extraordinary & Other Items	
6205-Donations	1,000
6210-Life Insurance	0
6215-Penalties	0
6225-Other Deductions	0
4100-Extraordinary & Other Items Total	**1,000**
Net Income - (Gain)/Loss	**(648,004)**

RECONCILIATION BETWEEN PRO FORMA STATEMENTS AND REVENUE DEFICIENCY STATEMENTS

No reconciliation is required between the 2013 Pro Forma statement and the revenue deficiency statement.

MATERIALITY THRESHOLDS:

Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, issued by the Board June 28, 2012 out lines the materiality thresholds which are dependent on the magnitude of the revenue requirement. As IHDSL's revenue requirement is less than $10 million, we will be using the $50,000 materiality threshold.

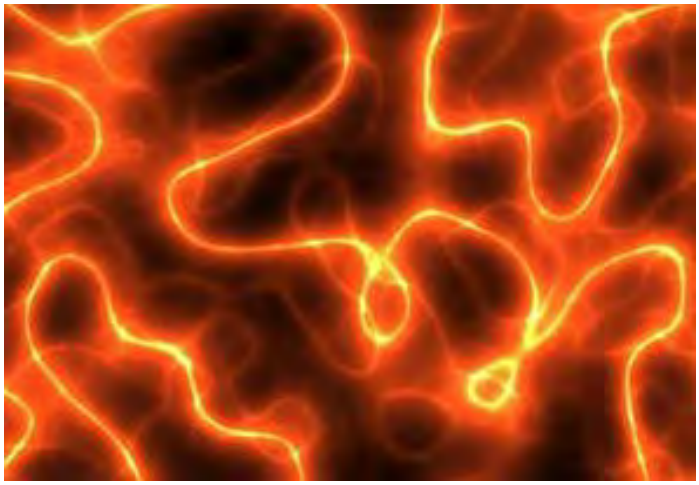
IHDSL 5 YEAR BUSINESS PLAN

IHDSL has attached it's Five Year Business Plan, which provides the foundation for the Cost of Service application.

APPENDIX H

5 YEAR BUSINESS PLAN

WMSFIL HYDRO DISTRIBUTION SYSTEMS LIMITED



Business Plan 2012

For years 2013 to 2017

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5. Engineering Five Year Capital Plan ..... Page 20
6. Financial Five Year Forecast Plan and Rates ..... Page 30

Appendix 1 – Financial Forecast

Appendix 2 – Load Growth Calculation 2011 to 2031

Appendix 3 – Asset Management Plan

Appendix 4 – Reliability Management Plan

Appendix 5 – Health & Safety Business Plan

Appendix 6 - South Simcoe County Area Study Final Report 2011

Appendix 7 – Asset Management Plan Review

Appendix 8 – Green Energy Plan

Appendix 9 – 2013 Detailed Capital Budget Sheets

Background

The Innisfil Hydro Electric Commission was originally formed in January 1991 and in July 1993, the distribution assets were purchased from Ontario Hydro for the service area expansion as provided for in Bill 185. 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 defined boundary as the Town of Innisfil as of January 1, 1994) to operate its distribution system within the licensed territory of 292 square kilometres in the Town of Innisfil and the south part of the City of Barrie with the passing of *Bill 196, Barrie-Innisfil Boundary Adjustment Act, 2009*.

As of January 1, 2010, 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 has 5 “in-house” Linemen and associated equipment. Major construction projects and substation maintenance is contracted out to independent contractors. A service agreement has been negotiated with the Town of Innisfil in order for Innisfil Hydro to put water and wastewater billing onto the existing monthly Hydro bills starting August 1, 2012. This has triggered the need to accelerate the hire of a Customer Service Manager.

The Head Office and Operations Centre for Innisfil Hydro is located at 2073 Commerce Park Drive in Innisfil, Ontario with 34 full-time staff. The site consists of a Customer Service building, an Engineering and Finance building, a Warehouse building and two public school portables situated on approximately 3.3 acres. The site was purchased from Pan-Abode model log homes & cabins.

Innisfil Hydro’s positive cash flow from operations ceased in 2009 due to capital requirements. Dividend payments are projected to be consistent over the next five years at $625,000 per year.

GO Transit service to Barrie has commenced in 2008 with a proposed Innisfil GO Train station situated at 20th Sideroad and 5th Line not expected until after 2013. The 400 Industrial Park development is extremely slow due to the lack of waste water treatment. The Town of Innisfil has completed a business plan to bring full municipal servicing to the 400 Industrial Park area. Timelines for servicing decisions in not expected until the fall of 2012.

The Provincial Government’s Intergovernmental Action Plan (IGAP) Report was released on August 29, 2006. The report has deduced that the population of Simcoe County would be 667,000 by year 2031. It is projected that by 2031, Innisfil Hydro will service 56,000 people in Innisfil with another 39,000 people in the new Barrie lands.

Sturdy Power Line is contracted until June 30, 2013 and the Olameter meter reading and billing contract is being renegotiated in 2012 to accommodate water and wastewater billing. The collective agreement with the local union has been negotiated until July 2013.

Innisfil Hydro is a member of the *Cornerstone Hydro Electric Concepts Association Inc.* (CHEC), George Shaparew sits on the Board of Directors. The group has 12 LDC members

(representing >100,000 customers) that have hired staff to perform 'back office' functions for its members. A Chief Operating Officer was hired in early 2009 and now they have a total of 4 full time staff.

IHDSL remains an active member in the Electricity Distributors Association. Liability, equipment, property, vehicle, bad debt and crime insurance are with MEARIE, which is a division of the EDA. MEARIE is a reciprocal insurance exchange that is owned by its members. We therefore receive insurance coverage at much lower rates than other market insurance providers.

1. Innisfil Customer Growth Assumptions

Following the aftermath of the *Oak Ridges Moraine Protection Act 2001*, 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/official-plan

The County of Simcoe Official Plan (2008);

http://www.simcoe.ca/ws_cos/media/media/planning%20files/OP%20Consolidation%20August%202007%20-%20TEXT%20FINAL.pdf

Draft Proposed Modified County of Simcoe Official Plan (2012)

http://www.simcoe.ca/dpt/pln/index.htm

Places to Grow, Simcoe Strategy;

https://www.placestogrow.ca/index.php?option=com_content&task=view&id=210&Itemid=15

https://www.placestogrow.ca/index.php?option=com_content&task=view&id=165&Itemid=15

Proposed Amendment 1 (2010) to the Growth Plan for the Greater Golden Horseshoe, 2006

https://www.placestogrow.ca/index.php?option=com_content&task=view&id=210&Itemid=15

The Provincial Government's IGAP Report was released on August 29, 2006 and is located at URL

http://www.simcoe.ca/ws_cos/media/media/IGAP-ECA---Communities-Report---MARCH-15-2006-FINAL.pdf

The Barrie-Innisfil Boundary Adjustment Act, 2009;

http://www.mah.gov.on.ca/Page6474.aspx

The Town of Innisfil's Official Plan (2006) and the County of Simcoe's Official Plan (2008) growth projections have been summarized below:

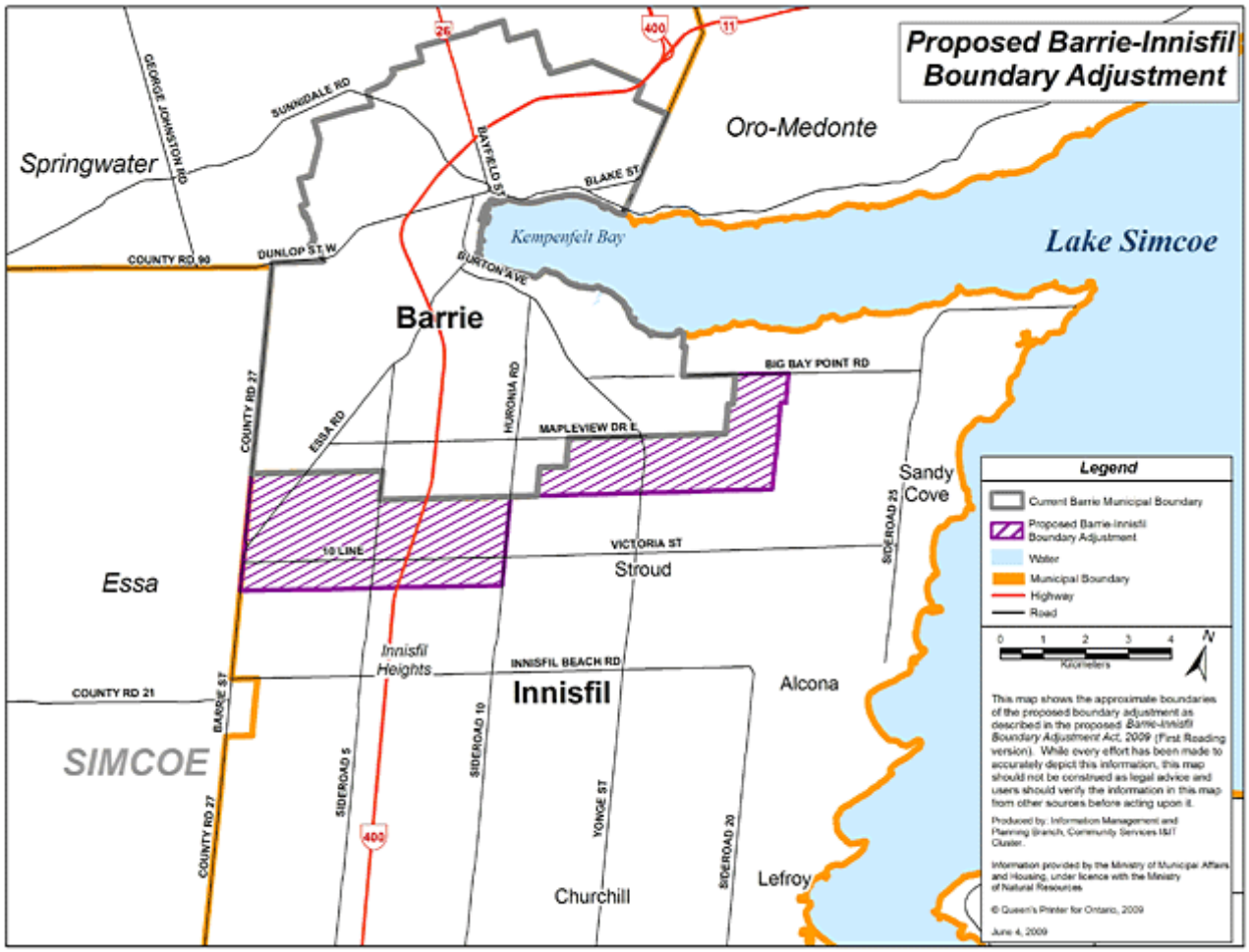
Official Plan	Population 2006	Population 2026	Employment 2006	Employment 2026
Innisfil	32,400	55,000	5,700	27,700

Official Plan	Population 2006	Population 2031	Employment 2006	Employment 2031
Simcoe	32,400	65,000	5,700	13,100

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 the long range plan. 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.

By virtue of the short timelines provided for distributors to make an offer to connect (60 days) versus years it takes to complete large capital projects, the distributor is therefore obligated to plan and build infrastructure in advance of a request for connection as a normal course of business.



The Barrie-Innisfil Boundary Adjustment Act was effective on Jan 1, 2010. This has granted the City of Barrie approximately 2,300 hectares of Innisfil lands for their development purposes. Until the City of Barrie releases an official plan amendment, 39,000 residents, or 80MW of demand, has been estimated for this service territory by 2031. These lands are in Innisfil Hydro's licensed distribution territory and long term plans have been incorporated in that regard.

There are five commercial development sites around the Highway 400 and Innisfil Beach Road area with a potential of over 100 lots. Three out of the five commercial sites were approved in 1990, 1991 and 1993. There has been an environmental assessment on-going for the impact of water and waste-water facilities around the Highway 400 corridor. Future development from Metrus Properties has proposed development for ~50,000 residents and 20,000 commercial jobs north of Georgian Downs. Preferred water and waste-water servicing for this area has been recommended from the City of Barrie, but not entertained by Barrie. Hydro servicing for such a development would require a 70 MW supply either with 3-44kV feeders or a preferred 230kV – 27.6kV T.S. The scope of such an undertaking is not anticipated within this 5-year plan but has been discussed with Hydro One and PowerStream (Appendix 6).

Long range planning strategies has been discussed with Hydro One and neighbouring South Simcoe LDCs. Innisfil Hydro believes that its best strategy for service supply post 2020 involves the deployment of an Innisfil Transformer Station 230kV – 27.6kV. Hydro One has indicated that Barrie TS will reach the end of it useful life in 2020. If Barrie TS gets rebuilt from 115kV to 230kV supply, it is then possible to run a double two circuit 230kV compact tower line down the 100' 13M3 easement from Barrie TS into Innisfil. A three acre property for a new 230kV – 27.6kV TS has been purchased in 2012. If a 230kV supply is delayed or not possible, the new TS site could be supplied with 115kV or even multiple 44kV sub-transmission circuits.

A resort community (Friday Harbour) is planned within the development of Big Bay Point Marina has been approved by Council and by the Ontario Municipal Board. This 600 acre site will consist of approximately 1,600 + new customers over a ten year period. It is anticipated that development would commence in 2014. It will be built to 28kV standards supplied with a new 44kV-27.6 kV Distribution Station, being ultimately replaced with 27.6kV supply from a new T.S. Both Innisfil Hydro and the Town of Innisfil have approved a land swap consisting of a 1/10th acre parcel (Alcona DS) to be sold to the Town in exchange for a one acre parcel at the Big Bay Point Road gravel pit. Innisfil Hydro will build its distribution station to supply load growth at the resort community, along with future load in the new Barrie lands and will provide 27.6kV backup to the Brian Wilson DS in Alcona.

The Lefroy area has development approval for approximately 2,300 customers. Together with the anticipated GO Train station on 5th Line, a new 27.6kV feeder extension from 7th Line to 4th Line will be required within a five year horizon. To meet the demands for Lefroy and a back-up for Alcona, a new 44kV-27.6kV Distribution Station is planned for Lefroy.

The following chart was provided by the Town of Innisfil and projects Innisfil new dwelling construction activity from 2009 to 2031.

Estimated New Dwelling construction activity

Area	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Alcona	260	260	260	260	260	260	260	260	260	260
Cookstown	c	50	50	50	50	50	50			
Gilford		2	2	2	2	2	2	2	2	2
Lefroy			50	50	50	50	50	50	50	50
Big Bay Point (Res)			b	100	100	100	100	100	100	100
New Growth Areas				a		100	100	100	100	100
Balance (rural)	25	25	25	25	25	25	25	25	25	25
Totals	285	337	387	487	487	587	587	537	537	537

Area	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Totals	Population
															30000
Alcona	260	260	260	260	260	260	260	260	260	260	260	260	260	6455	18719.5
Cookstown														300	870
Gilford														18	52.2
Lefroy	50	50	50	50	50	50	50	50	50	50	50	50	50	1050	3045
Big Bay Point (Res)	100	100	100	100	100	100	100	100	100					1600	4640
														0	0
New Growth Areas	100	100	100	100	100	100	100	100	100	100	100	100	100	1800	5220
Balance (rural)	25	25	25	25	25	25	25	25	25	25	25	25	25	625	1812.5
Totals	535	535	535	535	535	535	535	535	535	435	435	435	435	11848	64359.2

Utilizing growth projections from all available data, the following comprises the parameters for long range growth projections:

- Innisfil population in 2031 56,000
- New Barrie land population in 2031 39,000
- Big Bay Point development 1,600 units + commercial load

Further residential growth forecasts from Hemson Consulting as presented to Town Council on November 26, 2009, it is projected for 2010 – 150 units, 2011/12 – 200 units, 2013 – 300 units and 2014+ 600 units per year. Innisfil Hydro's projection is more conservative than the Town's estimated new dwelling activity. It is felt that Innisfil Hydro's conservative estimates more closely mirror the economic down-turn felt in the housing market. Factoring additional commercial customer growth, the following growth assumptions have been forecasted over the next five years:

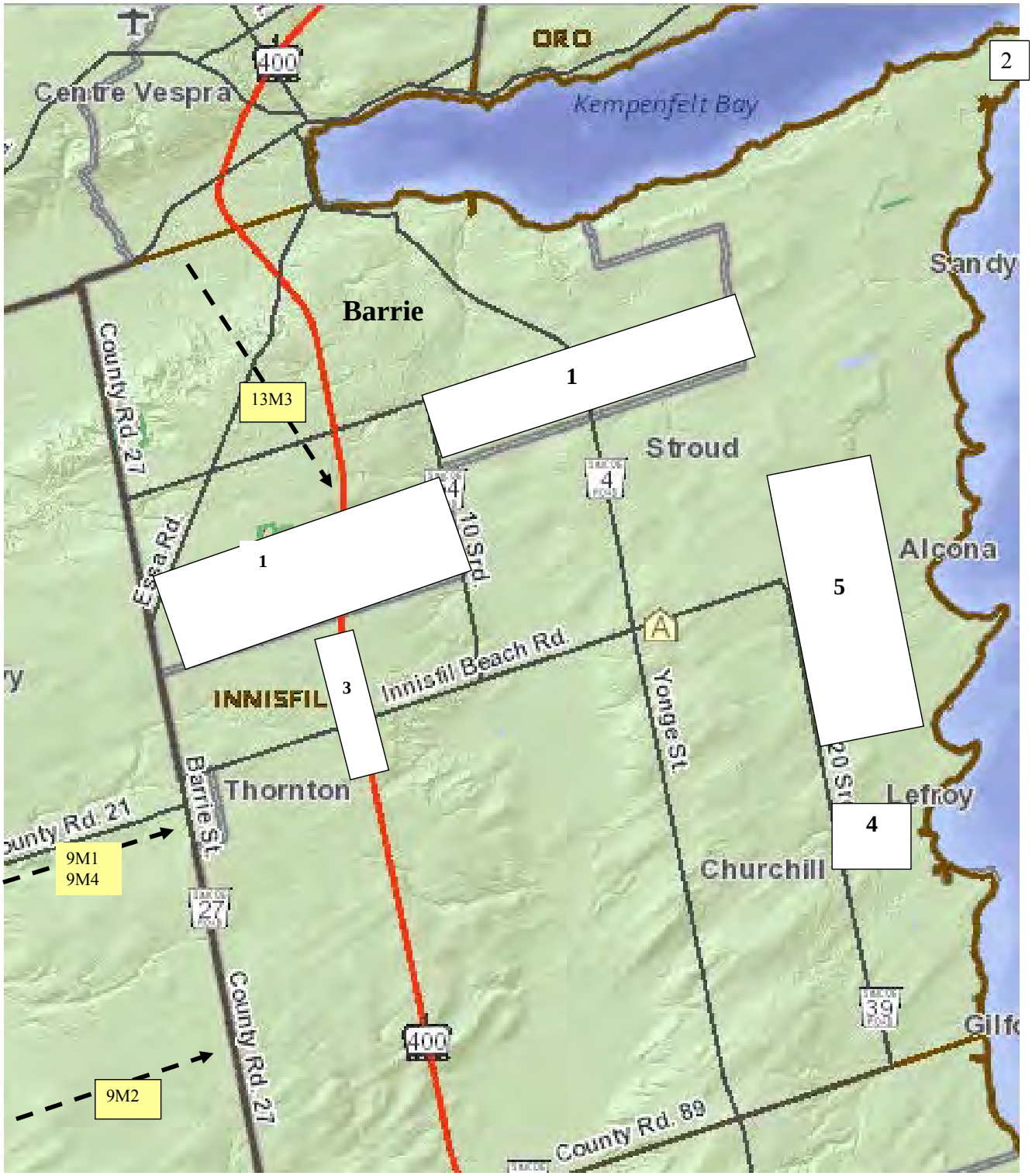
Customer Growth Assumptions

	Forecast 2012	Projection 2013	2014	2015	2016	2017
Total Customers Y/E	15,020	15,219	15,666	16,360	17,193	18,052
Residential Growth	192	194	421	652	781	805
GS < 50 Growth	4	5	24	38	49	51
GS > 50 Growth	(2)	(0)	2	3	4	4

Innisfil Hydro Load Growth by location

New Load by 2024 Total - 80MW
Zone 1 – 40 MW
Zone 2 – 8MW
Zone 3 – 10 MW
Zone 4 – 8 MW
Zone 5 – 14 MW

G Shaparew Mar 1, 2010



2. Human Resources Five Year Plan

A new Collective Agreement between Innisfil Hydro Distribution Systems Limited and Power Workers' Union C.U.P.E. Local 1000 Innisfil, was ratified in 2010 and expires on July 6, 2013.

During the past year, Innisfil Hydro hired a Customer Service Manager and a Smart Grid Engineer. The Customer Service Manager was hired to facilitate the inclusion of water and waste water billing, in addition to providing other mid-management assistance to the Vice President of Corporate Services.

In an effort to meet the need for succession planning for the Engineering Manager position, as well as to replace the retiring contract Protection and Control engineer, a recent Smart Grid Engineer/Engineer-in-Training was hired. This position will also be responsible for the coordination and administration of Innisfil Hydro's smart grid initiatives.

The 2012 rate application was submitted to the Ontario Energy Board (OEB) involving an Incentive Rate Mechanism (IRM). The allotted IRM rate increase that was approved was 0.88% for May 1, 2012. This nominal increase of 0.88% in distribution rates has put pressure on service delivery requirements since the collective agreement incorporated a 3% wage increase in 2012.

In 1212, Staff are preparing a Cost of Service (COS) application for submission to the OEB at the end of August, setting rates for the next four years. The following new positions will be included in the COS application for 2013 and will require approval from the Board of Directors:

- **Meter Technician** – *Required for back-up to the one incumbent and to start meter re-verification on all smart meters.*
- **IFRS Analyst** – *Required to administer IFRS implementation in addition to financial, regulatory and tax reporting.*
- **Purchaser/Stock Keeper**– *Required for back-up to the one incumbent and for custodianship of the new building*
- **Customer Service Representative** – Required for *Water / Wastewater and Power customer growth and regulatory burdens*
- **Regulatory Analyst (1/2)** – *Required to meet regulatory reporting requirements.*
- **Smart Grid Technician –** *Required for new SCADA software, network changes and new Smart Grid hardware. Funded through the Smart Grid Rate Rider*.

Although Hydro One has anticipated an increase in retirements due to their aging work force, it is not as critical for Innisfil Hydro. Innisfil Hydro was formed in 1993, and, therefore, does not have the same problem as more mature LDCs because there are few employees that have long service levels with the OMERS pension plan. However, two senior Innisfil Hydro managers are eligible for retirement in 2015. Discussions with a management consultant have begun for a non-union succession plan analysis to help establish seamless progression.

The following table outlines the estimated growth expectations with a predicted employee per customer ratio (end of year). It is worthwhile noting that new staff resources correlate to the cost of service rate applications that occur every four years. A Smart Grid (SCADA) Technician for 2013, funded by the Smart Grid Rate Rider has not been shown.

Human Resources Five Year Plan

	Forecast 2012	Projection 2013	2014	2015	2016	2017
Customer Growth	194	199	448	693	833	860
Customer Growth %	1.8%	1.3%	2.9%	4.4%	5.1%	5.0%
Total Customers Y/E	15,020	15,219	15,666	16,360	17,193	18,052
Employees	34.0	38.5	38.5	38.5	38.5	45.5
Customer to employee	442	395	407	425	447	397

Headcount by year	Forecast 2012	Projection 2013	2014	2015	2016	2017
President	1	1	1	1	1	1
HR	1.5	1.5	1.5	1.5	1.5	2
Ops Mgmt	2	2	2	2	2	2
Stores clerk	1	1	1	1	1	1
Purchasing	0	1	1	1	1	1
Techs	3	3	3	3	3	3
Ops clerk	1	1	1	1	1	1
Finance Mgmt	2	2	2	2	2	2
Regulatory/CDM	2	2.5	2.5	2.5	2.5	3
Accounting	1.5	2.5	2.5	2.5	2.5	2.5
CS Mgmt	3	3	3	3	3	3
IT	1	1	1	1	1	2
CSRs	7	8	8	8	8	8
Metering	1	2	2	2	2	2
Line crew	5	5	5	5	5	8
Locator	0	0	0	0	0	1
P Eng	1	1	1	1	1	1
GIS	1	1	1	1	1	1
SCADA	0	0	0	0	0	1
Total	34	38.5	38.5	38.5	38.5	45.5

3. Conservation and Demand Management Plan

The *Green Energy Act 2009* received royal assent on May 14, 2009. With this Bill, energy conservation and demand management is now a condition of the distribution license. In support of the *Green Energy Act 2009* and further Ministerial direction, the Ontario Energy Board (OEB) has issued energy reduction targets and CDM Codes for local distribution companies. The energy targets have to be achieved throughout the 2011-2014 timeframe.

Innisfil Hydro's targets are as follows:

Demand – 2.5 MW
Energy Reduction – 9.2 GWH

The energy reduction targets assigned by the OEB are equivalent to 700 residential homes within Innisfil Hydro's service territory. The targets will be met by a combination of OPA approved programs and conservation programs specific to Innisfil Hydro's service territory requirements known as OEB approved programs.

Innisfil Hydro registered/offered all the OPA programs (Tier 1) within the Consumer, Commercial & Institutional, Industrial, and Home Assistance portfolios for 2011-2014. In line with our customer rate class ratios the primary focus of the 2011 CDM program was on the Residential and General Service (GS) customer rate classes to promote awareness of the "saveONenergy" programs and the provincial website.

The transitional issues from the 2010 CDM programs and complete implementation of the 2011- 2014 OPA CDM programs has been extremely fragmented thus impacting Innisfil Hydro's ability to secure base energy savings to build cumulative persistence energy savings. The majority of programs and associated tools were not available until June 2011, and 2 programs within the Consumer Program have never been implemented (Mid-stream electronics and Consumer Conservation Card). Additionally, 2 programs that were estimated to greatly enhance residential savings (Home Assistance Program and *peaksaver **plus***) were not ready for implementation until 2012.

The following tables identify IHDSL's forecasted 2014 results and 2011 actuals by program;

OPA-Contracted Province-Wide CDM Programs DRAFT 2011 Results

LDC: Innisfil Hydro Distribution Systems Limited

DRAFT Progress to Targets	Incremental 2011	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	0.2	**3.8%**	**9.4%**
Net Cumulative Energy Savings (GWh)	0.6	**23.7%**	**23.8%**

Scenario 1 = Assumes that demand resource resources have a persistence of 1 year

Scenario 2 = Assumes that demand response resources remain in your territory until 2014

Note: all highlighted programs were not ready for implementation in 2011 at the time of the Master Agreement

IHDSL – OPA 2011 Tier 1 Participation

#	Initiative	Activity Unit	Uptake/ Participation Units
Consumer Program			
1	Appliance Retirement	Appliances	250
2	Appliance Exchange	Appliances	13
3	HVAC Incentives	Equipment	188
4	Conservation Instant Coupon Booklet	Products	2,037
5	Bi-Annual Retailer Event	Products	3,439
6	Retailer Co-op	Products	0
7	Residential Demand Response	Devices	233
8	Residential New Construction	Houses	0
Business Program			
9	Efficiency: Equipment Replacement	Projects	1
10	Direct Install Lighting	Projects	11
11	Existing Building Commissioning Incentive	Buildings	0
12	New Construction and Major Renovation Incentive	Buildings	0
13	Energy Audit	Audits	0
14	Commercial Demand Response (part of the Residential program schedule)	Devices	5
15	Demand Response 3 (part of the Industrial program schedule)	Facilities	0
Industrial Program			
16	Process & System Upgrades	Projects	0
17	Monitoring & Targeting	Projects	0
18	Energy Manager	Managers	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Projects[1]	0
20	Demand Response 3	Facilities	0
Home Assistance Program			
21	Home Assistance Program	Homes	0
Pre 2011 Programs Completed in 2011			
22	Electricity Retrofit Incentive Program	Projects	0
23	High Performance New Construction	Projects	1
24	Toronto Comprehensive	Projects	0
25	Multifamily Energy Efficiency Rebates	Projects	0
26	Data Centre Incentive Program	Projects	0
27	EnWin Green Suites	Projects	0

In order to meet Innisfil Hydro's target for energy and demand savings an incremental volume of 20 % energy savings will have to be achieved in 2012. To achieve these required energy savings, Innisfil Hydro will focus primarily on the GS customer rate class (<GS 50 and >GS 50). The following strategies have been developed to accomplish this goal,

- Contractor sessions to promote the value add proposition of ERII rebates
- Specialized sessions for farm sector, OMAFRA on rebate programs and control of increased energy costs
- Personalized targeted visits to large use customers to promote the rebate programs and value add from Innisfil Hydro
- Partnerships with local builders to participate with the Residential New Construction program
- Targeted media on the success stories of customers who have already participated in the saveONenergy programs
- Focused direct mail to increase *peaksaver **plus*** participation
- Sandy Cove information sessions to promote the Home Assistance Program

In addition to the focus on our business program, Innisfil Hydro will still continue to participate in community events to deliver the CDM message to its residential customers.

4. Information Technology and Metering Five Year Capital Plan

Information Technology (IT) is an integral part of the electricity industry in Ontario. The challenges and demands for increased efficiencies and security with zero 'down time' provide on-going opportunities to improve our network infrastructure and integrity. A comprehensive security audit of our internal network is being conducted in 2012 and any remedial actions will be undertaken in 2013. Security audits will be undertaken every second year thereafter.

Electricity retailers continue to be active in our service area, renewing contracts and enrolling new customers. There are service agreements with twenty electricity retailers, of whom twelve have active enrollments. North Star Utilities Division of Harris Computer Systems and SPi provide dependable software solutions that allow us to transact in excess of 138,000 Electronic Business Transactions (EBT) per year with electricity retailers via our Customer Information and Billing System (CIS).

The Alliance Service Bureau operated by Savage Data Systems continues to provide timely processing of our daily settlement statements from the Independent Electricity System Operator (IESO). Embedded generation has been integrated into our daily settlement files by the Service Bureau for import into the CIS.

An upgrade to the Customer Information Systems (CIS) is planned for 2013 to take advantage of programming enhancements from North Star Utilities and enhanced reporting functionality to facilitate reporting requirements for the Low-income Energy Assistance Program.

Implementation of 'Springboard' software has automated the tracking of Human Resources training-2012. It will be the first year of tracking training compliance with this new tool. Upgrades to the Penny Software for timesheet input has been implemented and input to Ceridian Canada for payroll is now web-based.

An upgrade of Microsoft Great Plains (MGP) to the current version is planned for 2014. IFRS implementation is ongoing and further integration with engineering software is planned for 2013.

Engineering continues to build on the implementation of a topobased solution supplied by AutoCad via Automated Solutions Inc. (ASI). The integration of CYME software for distribution system planning, analysis, Connection Impact Assessment for distributed generation with the topobased solutions will continue from 2012 forward. ASI's applications for outage management, work order estimating and asset management will also make use of the topobased technology against an oracle database. Network virtualization is scheduled for completion in 2013.

A multi-year project that commenced with the "*Energy Conservation Leadership Act, 2006" (Bill 21)* which received royal assent on March 28, 2006 was completed in 2011. This Act included amendments to the *Electricity Act, 1998* to allow for the establishment of a "Smart Metering Entity" to implement "Smart Metering" in Ontario. The underlying premise behind the provincial mandate to install these meters was to educate consumers on their consumption habits and implement new rate structures that would encourage load shifting and the conservation of energy.

The Ministry of Energy tasked the IESO with the development of a Meter Data Management/Meter Data Repository (MDM/R) including the workflow and interfaces that are required between the MDM/R, Local Distribution Companies (LDCs), Advanced Metering Infrastructures (AMI) and CIS. The Ministry of Energy continues to oversee ongoing policy and monitoring of the Smart Metering Initiative (SMI) to ensure the Government's policy objectives are met. The initial goal was to have a 'smart meter' installed in every residential and small commercial premise in Ontario.

Innisfil Hydro, in conjunction with the Cornerstone Hydro Electric Concepts (CHEC) group of distributors and a consulting firm (Util-Assist), participated in the Ministry approved London Hydro Phase II RFP which was overseen by a Fairness Commissioner, Mr. Peter Sorensen. By virtue of participation in this Ministry approved process, we were named in regulation and proceeded with implementation of an AMI in Innisfil.

The AMI installed is a tower based solution for communicating with deployed smart meters. Two existing towers were chosen, the Town of Innisfil's Churchill Tower and the Town's Big Bay Point Tower on Innisfil Hydro's substation site.

Innisfil Hydro is registered with the provincial MDM/R and successfully cut-over to the production environment of the MDM/R in late March 2011. The required reading success rate between the Sensus AMI and the MDM/R is being maintained.

The OEB amended the Standard Supply Service Code on August 4, 2010 to establish a mandatory time-of-use billing schedule. For Innisfil, the start month was June 2011 for time-of-use (TOU) billing rates on June consumption. With the implementation of TOU billing, printing meter readings on customers' bills was temporarily suspended. The MDM/R stores both meter readings as well as TOU data, however the system was not designed to pass meter readings when responding to billing quantity requests from LDC's.

Measurement Canada mandated that meter readings again be presented on customers' bills by January 2012. In May 2012, start and end meter readings on customers' bills was reinstated. By 2013, a permanent solution with additional functionality is to be implemented in the MDM/R. More testing between the CIS and the MDM/R will be required in advance of updating the production environment in the CIS.

As part of a consortium of 33 LDC's, Innisfil Hydro participated in a security audit of the AMI in 2012. The audit findings were distributed in early 2012; ongoing remediation efforts are being undertaken by the 'Smart Meter' vendor, Sensus Metering Systems Inc. to address vulnerabilities identified by the audit. Any additional remediation require as a result of a 2012 audit will be implemented in 2013-2014.

Between 2013 and 2017 significant system integration will be undertaken to link Smart Meter data from the Operational Data Store (ODS) with the Geographic Information System (GIS), Supervisory Control and Data Acquisition (SCADA) and Outage Management System (OMS) to streamline operations and facilitate 'smart grid' development. During this time, further integration is planned between Microsoft Great Planes (MGP) and the GIS for the International Financial Reporting System (IFRS) final implementation and asset management. Additionally, CYME modeling software will be linked with the GIS. During this time, re-verification of installed Smart Meters will also commence. Next generation smart meters will also be available enabling 2 way communication for in-home devices for consumers.

The following IT and Metering Five Year Capital Plan is designed to sustain the existing network infrastructure, server capacity, processing speed and user workstations required to operate efficiently and profitably in the electricity market. The goal is to facilitate system integration to improve efficiency while maintaining the high level of security required ensuring the integrity of electronic data.

General office furniture, equipment, buildings and fixture requirements for the next five years have also been included in this long range forecast.

5 YEAR CAPITAL PLAN for IT, Metering, Buildings

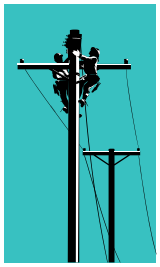
Hardware	2013	Description	2014	Description	2015	Description	2016	Description	2017	Description
Network Infrastructure GB003	15,000	Upgrade network infrastructure Replace firewalls	15,000	Upgrade network infrastructure	15,000	Upgrade network infrastructure Replace firewalls	15,000	Upgrade network infrastructure	15,000	Upgrade network infrastructure Replace firewalls
	13,000	Add network printers and other peripherals	13,000	Add network printers and other peripherals	13,000	Add network printers and other peripherals	13,000	Add network printers and other peripherals	13,000	Add network printers and other peripherals
	50,000	Network redundancy and security enhancements	50,000	Network redundancy and security enhancements	50,000	Network redundancy and security enhancements	50,000	Network redundancy and security enhancements	50,000	Network redundancy and security enhancements
Server Upgrades/ Replacement GB003	35,000	Virtualization Enhance/Replace	35,000	Virtualization Enhance/Replace	35,000	Virtualization Enhance/Replace	35,000	Virtualization Enhance/Replace	35,000	Virtualization Enhance/Replace
Workstation Unit Replacement GB003	15,000	Add and replace workstations & monitors cyclical by department	15,000	Add and replace workstations & monitors cyclical by department	15,000	Add and replace workstations & monitors cyclical by department	15,000	Add and replace workstations & monitors cyclical by department	15,000	Add and replace workstations & monitors cyclical by department
Metering										
Wholesale Meters	15,900	Wholesale Meter Upgrades	15,900	Wholesale Meter Upgrades	15,900	Wholesale Meter Upgrades	15,900	Wholesale Meter Upgrades	74,900	Add One Wholesale Meter (44kV)
Retail Meters DB001	100,150	Residential and C&I	100,150	Residential and C&I	100,150	Residential and C&I	100,150	Residential and C&I	41,150	Residential and C&I
Hardware Total	**$244,050**		**$244,050**		**$244,050**		**$244,050**		**$244,050**	
1860	116,050		116,050		116,050		116,050		116,050	
1920	128,000		128,000		128,000		128,000		128,000	
Total	**244,050**		**244,050**		**244,050**		**244,050**		**244,050**	

Software	2013	Description	2014	Description	2015	Description	2016	Description	2017	Description
Network Related GB003	15,000	Network Security Enhancements sql, 128 bit encryption	10,000	Network Security Enhancements Implement Security Audit Recommendations	15,000	Network Security Enhancements Implement Security Audit Recommendations	10,000	Network Security Enhancements Implement Security Audit Recommendations	15,000	Network Security Enhancements Implement Security Audit Recommendations
Server Related GB003	10,000	Exchange archive, physical vMotion	10,000	Exchange archive, physical vMotion	10,000	Exchange archive, physical vMotion	10,000	Exchange archive, physical vMotion	10,000	Exchange archive, physical vMotion
GB003	25,000	Harris NS upgrades-add licences	25,000	Harris NS upgrades-add licences	25,000	Harris NS upgrades-add licences	25,000	Harris NS upgrades-add licences	25,000	Harris NS upgrades-add licences
GF001	40,000	MGP upgrades	40,000	MGP upgrades and Integrations	40,000	MGP upgrades and integrations	40,000	MGP upgrades and integrations	40,000	MGP upgrades and integrations
GF001	7,500	Add Wennsoft licences	7,500	Add MGP licences	7,500	Add Wennsoft licences	7,500	Add MGP licences	7,500	Add Wennsoft licences
GO010	171,000	Engineering -topobase, CYME, IFRS integration,add AUD clients integrate GIS to AMI	171,000	Engineering -topobase, CYME, IFRS integration,add Topo clients integrate GIS to AMI	171,000	Engineering -topobase, CYME, IFRS integration,add AUD clients integrate GIS to AMI	171,000	Engineering -topobase, CYME, IFRS integration,add Topo clients integrate GIS to AMI	171,000	Engineering -topobase, CYME, IFRS integration,add AUD client integrate GIS to AMI
Workstation Related GB003	10,000	Workstation apps upgrade cyclical by department	15,000	Workstation apps upgrade cyclical by department	10,000	Workstation apps upgrade cyclical by department	15,000	Workstation apps upgrade cyclical by department	10,000	Workstation apps upgrade cyclical by department
Software Total-1925	**$278,500**		**$278,500**		**$278,500**		**$278,500**		**$278,500**	

Building, F&F	2013	Description	2014	Description	2015	Description	2016	Description	2017	Description
1908	35,000	Miscellaneous-existing location	52,500	Miscellaneous additions/fixtures	52,500	Miscellaneous additions/fixtures	52,500	Miscellaneous additions/fixtures	52,500	Miscellaneous additions/fixtures
GB001minus DR,GB002	17,500	New Building - Misc		at New Building and DR site		at New Building and DR site		at New Building and DR site		at New Building and DR site
GB001 DR	75,000	Start new DR site	75,000	Complete new DR site	50,000	Replace one 'unit' at DR site	50,000	Replace second 'unit' at DR site	50,000	Add new 'unit' at DR site
1915	35,000	Miscellaneous	35,000	Miscellaneous	35,000	Miscellaneous	35,000	Miscellaneous	35,000	Miscellaneous
		Add/replace furniture&equipment		Add/replace furniture&equipment		Add/replace furniture&equipment		Add/replace furniture&equipment		Add/replace furniture&equipment
		cyclical by department		cyclical by department		cyclical by department		cyclical by department		cyclical by department
Total	**$162,500**		**$162,500**		**$137,500**		**$137,500**		**$137,500**	
Grand Total	**$685,050**		**$685,050**		**$660,050**		**$660,050**		**$660,050**	

Summary	2013		2014		2015		2016		2017	
1860	116,050		116,050		116,050		116,050		116,050	
1920	128,000		128,000		128,000		128,000		128,000	
1925	278,500		278,500		278,500		278,500		278,500	
1908	127,500		127,500		102,500		102,500		102,500	
1915	35,000		35,000		35,000		35,000		35,000	
Total IT & Metering	**685,050**		**685,050**		**660,050**		**660,050**		**660,050**	
Engineering capital	**8,335,802**		**5,257,224**		**5,469,323**		**5,578,857**		**5,519,149**	
WIP changes	**-**		**-**		**-**		**-**		**-**	
Total IHDSL capital	**9,020,852**		**5,942,274**		**6,129,373**		**6,238,907**		**6,179,199**	

5. Engineering Five Year Capital Plan



The capital infrastructure necessary to meet the 20-year demand, which is more than double the existing demand, will require long term planning with staging of the capital infrastructure. Failure to plan capital requirements will prohibit Innisfil Hydro from meeting the needs of the growing community, which would, therefore, restrict growth due to lack of capacity, contrary to the Distribution System Code (DSC).

The 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."*

Furthermore, the introduction of *Ontario Regulation 22/04*, Electrical Distribution Safety, in late 2004 established 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. Appendix 3 includes the Asset Management Plan which was first developed in 2008.

Whether O&M or Capital, programs are generally prioritized as follows:

1. Health & Safety
2. Legislative
3. Growth
4. Reliability

The new Innisfil Hydro Head Office and Operations Center is slated to start construction in the fall of 2012. The 2013 budget reflects the necessary investment to enhance Innisfil Hydro's effectiveness and operations with all departments under one roof rather

than the five (5) buildings currently being utilized. Growth requirements and structural deficiencies have prompted this required expansion.

A new Supervisory Control and Data Acquisition (SCADA) software program began in 2012. The outdated SCADA program does not have enough capacity to include new operational devices. The new SCADA system is a step towards Smart Grid implementation and can accommodate an enhanced capacity server, work stations, and an extensive number of control points for new operational devices. The new SCADA implementation features enhanced reliability, faster response time and has the capability to talk with other SCADA systems outside of Innisfil Hydro's network as well. In an effort to mitigate costs, discussions are on-going with the Town of Innisfil's water and wastewater departments to share network communications.

Furthered growth in Innisfil Hydro's SCADA network will occur in the presented five year plan consisting of both 44 kV and 27.6 kV automated switches. There are a number of old mid span openers and air break switches that will be replaced with remote operable load break switches. These new devises in the 44kV and 27.6 kV systems will provide remote switching capability and real time data acquisition to better manage outage reporting numbers to the OEB. Crew time will be reduced during emergency and non-emergency operations and built in functionality can be used for future smart grid, self healing considerations.

Recloser automation has been planned in each year from 2013 to 2017. Electronic Vacuum style reclosers with electronic relay controls are planned to replace the oil filled hydraulic reclosers providing remote communication via the SCADA network and the recording of momentary and operational data. The electronic reclosers play a compulsory role in the Self healing, smart grid system.

Pole replacements, infrastructure betterments, substandard transformer replacements and pad mounted transformer replacements have been carried forward from year to year to address the need to remove and replace rotten and damaged poles and substandard or defective devices that pose a danger to the public and safety of workers.

A 2009 pole replacement project on the 20th Sideroad will accommodate the line extension planned in 2013 to egress 27.6 KV into the Big Bay Point (BBP) area from Brian Wilson DS to make a future operational feeder tie. This line will become increasingly important to ensure the new BBP station projected in 2015 is not islanded without back up in an emergency or for planned station maintenance. To support the Friday Harbour development start up, a section of line will be constructed from the newly built 27.6kV line extension easterly to the south entrance of the resort.

In 2014, the construction of a new Distribution Station in the Lefroy area is required to facilitate growth needs of the Lefroy secondary plan. With this new station, a link to the Brian Wilson DS has been facilitated in the 5 year forecast in 2014 with a 27.6 kV line extension from the 7th Line to the 5th Line on the 20th Sideroad, combined with additional re-poling and re-conductoring between the 6th and 7th Lines on the 20th Sideroad. A pole replacement and line extension project completed in 2010/2011 has set the foundation for connecting the new Lefroy station which will provide excellent

redundancy to the south end of Alcona and avoid islanding new customer growth in Lefroy.

In 2014, the start of distribution expansion for the new Barrie lands is expected. Rebuilding of old infrastructure on Yonge Street north of Lockhart Road and west on Mapleview (some dating back to the early 1950's), will supply the Mapleview west location within the City of Barrie with 3 phase power for anticipated customer growth. This line will also facilitate feeders from a possible station expansion of Stroud DS with an additional 5 MVA transformer (44-8.3kV) in 2016. For station back-up, the same expansion will need to occur at Sandy Cove DS. Another alternative being investigated that will eliminate the need to expand two stations, is to build a 44-27.6kV DS at the Innisfil TS site.

A rear lot relocation project is anticipated in 2014 to remove 415m of 1940's vintage single phase overhead primary infrastructure out of the back yards of customers' homes to the street front Boulevard. Accessibility, safety of workers and public, decreased outage times and the replacement of old infrastructure are a direct benefit of this project.

In 2015, the installation of a new Distribution Station in the Big Bay Point area to facilitate growth of the BBP Friday Harbour resort and surrounding area is planned. A land transfer between the Town of Innisfil and Innisfil Hydro has designated a location for the station in the Town's gravel pit. The new station, (44-27.6 KV), will also provide back up to the Brian Wilson station.

To energize the new BBP Distribution Station, a 44kV line extension from the 13th line north on 25th Sideroad is required in 2015. As part of the scope of works in this project, a 44kV supply is also needed by the Friday Harbour resort as a hotel facility reviewed from the developer's plans exceeds the maximum KVA size of transformer we can provide in the distribution system under the Conditions of Service.

With the anticipated growth in the Big Bay Point area, egress from the new station is forecasted as one of the projects in 2015. New feeders will go north and easterly into the Big Bay Point area as well as south to the 13th Line. This egress will provide the redundant tie for emergency or planned feeder maintenance.

In 2016, several other projects are anticipated to accommodate load growth in the City of Barrie's new Lands. Feeder egress from the 20th Sideroad and Mapleview area will extend 27.6 KV westerly to the Yonge Street. A 27.6 KV conversion and line rebuild from the 10th Line and 10th Sideroad area west over Highway 400 to the 5th Sideroad will replace old infrastructure while introducing 27.6 KV for future expansion. A line extension of a second 8.3kV circuit from the Stroud DS expansion in the Yonge Street and Mapleview areas will provide future growth needs and redundancy for circuit backup and station maintenance. Also in 2016, a 44kV pole line rebuild and replacement on Lockhart Road between the 25th Sideroad and Yonge Street will take place to rebuild the old infrastructure. This 44kV line supplies three distribution stations and two private station customers.

Phase 1 of a primary cable replacement in the Sandy Cove retirement community will occur in the year 2016. The underground cables in this development were installed in the early 1980's with the life expectancy of the cable in that era of 20-25 years. The aging cable within this development is direct buried which creates an obstacle in elbow replacement during failure or maintenance. Cable length is often not long enough to make repairs. Phase 2 of this project continues in 2017.

As presented in Appendix 2, load growth indicates the need for a new 44kV feeder in 2017. Feeder 9M6 from the Alliston TS will supply growth requirements until 2020. This new sub transmission feeder will be built on a recently constructed pole line equipped to accommodate a second 44kV feeder.

In 2017, 44kV pole replacements are required between the Mapleview and Lockhart road area on the 25 Sideroad to replace decaying and feathering sub transmission poles. Insect infestation has also been identified in poles replaced in this section of line. This project will set the stage for a future 27.6kV feeder tie between the Brian Wilson DS and the recently constructed Big Bay Point DS.

The Alliston 9M2 was successfully installed in 2009. Future load requirements and redundancy issues prompted this project. In 2017, a 44kV pole replacement and re-conductoring is necessary to replace pole infrastructure, some dating back to the 1950's along with 44kV conductor replacement from 336 kcmil AAC to 556 kcmil AAC as this section cannot accommodate full feeder capacity and is a week link. *Ontario Regulation 22/04* standards will dictate the pole replacement as the existing infrastructure cannot support the new weight of the 556 kcmil AAC.

In 2017, the replacement of a 1993 Double Bucket truck will be required. This truck was purchased second hand from another power company in 2010 and will be at the end of its useful life.

Load growth calculations have been presented in Appendix 2 outlining anticipated demand together with predicted supply from 2008 – 2031. Anticipated demand is based on 2KW per resident.

The 2008 decrease in reliability was caused by loss of supply from Hydro One and storm related outages. In 2009, a new 44kV feeder was put into service and tree trimming frequency was increased from four years to three years. A more in-depth reliability analysis is available in Appendix 4, (Reliability Management Plan). Capital budgets from 2013 to 2017 and a pending project pool list is presented in the following six pages. Appendix 9 includes a more detailed description of the Capital projects for 2013.

INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED

ENGINEERING BUDGET - 5 YR. FORECAST 2013

CAPITAL REQUESTS - DISTRIBUTION PLANT			Contributions	
Stn. Recloser automation, replacements & Ln. Recl. Maint.4 yr.Cycle	$	223,300		
44kV Mechanized scada controlled load Interrupting gang switches (2)	$	160,100		
27.6kV Mechanized scada controlled load interrupting gang switches (3)	$	253,180		
Infrastructure replacements and betterments	$	210,900		
U/G padmounted Transformer replacements and painting	$	79,700		
Substandard transformer re-habs	$	182,700		
2013 Pole Replacement	$	391,288		
27kV Extension 20th S.R., BBPT to 25th SR.	$	724,294		
Big Bay Pt. F3 for BBPT Development	$	110,743		
Utility relocates	$	101,112	$	33,026
CAPITAL REQUESTS - GENERAL PLANT				
New Building Construction	$	5,000,000		
Stand up inside Fork Lift	$	30,000		
Fleet vehicle replacement 2004 pick up 265000km/Add SCADA/Eng. Addition	$	80,000		
Stores equipment	$	4,200		
Tools, shop and garage equipment	$	20,000		
Measurement and testing equipments Locator replacement	$	19,000		
System supervisory	$	62,000		
Capacitor Intelilink to SCADA (2)	$	51,400		
44KV/27.6 kV Radio repeated fault indicators	$	38,400		
Topobase - Integration - IFRS	$	-		
BASE - CAPITAL				
1. Land right & legal easements	$	-		
2. Station ancillary equipment replacement & improvement	$	4,622		
3. Innisfil Hydro & customer contributed poles, towers & fixture works	$	104,990	$	29,270
4. Innisfil Hydro & customer contributed O/H conductor works	$	98,695	$	23,313
5. Innisfil Hydro & customer contributed u/g duct installations & relocates	$	9,243	$	4,108
6. Innisfil Hydro & customer contributed primary cable installations & relocates	$	75,485	$	40,762
7. Innisfil Hydro & customer contributed O/H TX relocates, replacements & upgrades	$	172,279	$	51,864
8. Innisfil Hydro & customer contributed U/G TX relocates,replacements & upgrades	$	106,345	$	73,378
9. Innisfil Hydro & customer contributed O/H secondary relocates,replacements & upgrades	$	21,875	$	7,189
10. Innisfil Hydro & customer contributed U/G secondary relocates,replacements & upgrades	$	175,725	$	119,493
11. Innisfil Hydro system supervisory & scada control	$	11,297		
12. Economic evaluation	$	195,332		
TOTAL	**$**	**8,718,205**	**$**	**382,403**
NET	**$**	**8,335,802**		

Distribution	$	8,049,505
General	$	286,297
Total Engineering Capital	$	8,335,802
IT & Metering	$	685,050
WIP changes	$	-
Total IHDSL Capital Expend	**$**	**9,020,852**
2013-2016 4 year average	**$**	**6,832,851**

ENGINEERING BUDGET - 5 YR. FORECAST 2014

CAPITAL REQUESTS - DISTRIBUTION PLANT		Contributions
Lefroy DS 44kV/27.6 Station	$ 1,400,000	
3 Phase 27.6kV Conductoring on 20th S.R. between 5th & 7th Lines	$ 290,115	
3 Phase 44kV Repoling-reconductoring 20th btwn. 6th & 7th	$ 256,550	
Line rebuild and feeder extension from Stroud DS to Barrie moritorium lands	$ 500,000	
27.6kV Mechanized scada controlled load interrupting gang switches (3)	$ 263,053	
44kV Mechanized scada controlled load Interrupting gang switches (2)	$ 166,344	
Stroud DS transformer replacement	$ 25,000	
Everton rear lot 1 phase relocate to street front	$ 300,000	
2014 Pole Replacement	$ 331,289	
Infrastructure replacements and betterments	$ 219,125	
Recloser automation & replacements DS - 4 year cycle replace	$ 232,009	
UG padmounted transformer replacements and painting	$ 82,808	
Substandard transformer re-habs	$ 189,825	
Utility relocates	$ 70,729	$ 34,314
CAPITAL REQUESTS - GENERAL PLANT		
Class 7 All Terrain Fork Lift Replacement	$ 80,000	
SCADA PME 2 (two) motorized switch gear installs IBR Urbanization	$ 70,000	
Fleet tools	$ 20,780	
Stores equipment	$ 4,364	
Tools, shop and garage equipment	$ 20,780	
Measurement and testing equipments Fault finder replacement	$ 13,507	
27.6 kV Radio repeated fault indicators	$ 39,898	
System supervisory	$ 64,418	
BASE - CAPITAL		
1. Land right & legal easements	$ -	
2. Station ancillary equipment replacement & improvement	$ 4,802	
3. Innisfil Hydro & customer contributed poles, towers & fixture works	$ 109,085	$ 30,412
4. Innisfil Hydro & customer contributed O/H conductor works	$ 102,544	$ 24,222
5. Innisfil Hydro & customer contributed u/g duct installations & relocates	$ 9,603	$ 4,268
6. Innisfil Hydro & customer contributed primary cable installations & relocates	$ 78,429	$ 42,352
7. Innisfil Hydro & customer contributed O/H TX relocates, replacements & up	$ 178,998	$ 53,887
8. Innisfil Hydro & customer contributed U/G TX relocates,replacements & up	$ 110,492	$ 76,240
9. Innisfil Hydro & customer contributed O/H secondary relocates,replacemen	$ 22,728	$ 7,469
10. Innisfil Hydro & customer contributed U/G secondary relocates,replacemen	$ 182,578	$ 124,153
11. Innisfil Hydro system supervisory & scada control	$ 11,738	
12. Economic evaluation	$ 202,950	
TOTAL	**$ 5,654,541**	**$ 397,317**
NET	**$ 5,257,224**	
Distribution	$ 4,931,740	
General	$ 325,484	
Total Engineering Capita	$ 5,257,224	
IT & Metering	$ 685,050	
WIP changes	$ -	
Total IHDSL Capital Ex	**$ 5,942,274**	
2013-2014 2 year average		**$ 7,481,563**

INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED

ENGINEERING BUDGET - 5 YR. FORECAST 2015

CAPITAL REQUESTS - DISTRIBUTION PLANT		Contributions
Big Bay Point DS 44kV/27.6 Station	$ 1,400,000	
F3 & F4 Feeder Extension from BBP DS to Big Bay Point Development	$ 705,194	
44kV line Extension from 13th Line on BBPT.Rd.and 25th SR N to BBPDS & Dev	$ 750,000	
Recloser automation & replacements Innisfil DS - 4 year cycle replace	$ 248,482	
Substandard transformer re-habs	$ 203,303	
27.6 kV mechanized scada controlled load interrupting gang switches (3)	$ 281,730	
44 kV mechanized scada controlled load Interrupting gang switches (2)	$ 178,154	
2015 Pole replacement program	$ 354,811	
Infrastructure replacements and betterments	$ 234,683	
Third party utility relocates	$ 75,751	$ 36,750
U/G padmounted Transformer replacements and painting	$ 88,687	
CAPITAL REQUESTS - GENERAL PLANT		
Fleet vehicle replacement 2- 2005 Dodge RAM 1/2 Ton	$ 85,000	
Fleet tools	$ 15,000	
Stores equipment	$ 4,674	
Tools, shop and garage equipment	$ 22,255	
Measurement and testing equipments Fault finder replacement	$ 14,466	
27.6 kV Radio repeated fault indicators	$ 42,731	
System supervisory	$ 68,992	
SCADA PME motorized switch gear install Green Acres	$ 35,000	
BASE - CAPITAL		
1. Land right & legal easements	$ -	
2. Station ancillary equipment replacement & improvement	$ 5,143	
3. Innisfil Hydro & customer contributed poles, towers & fixture works	$ 116,830	$ 32,571
4. Innisfil Hydro & customer contributed O/H conductor works	$ 109,825	$ 25,942
5. Innisfil Hydro & customer contributed u/g duct installations & relocates	$ 10,285	$ 4,571
6. Innisfil Hydro & customer contributed primary cable installations & relocates	$ 83,997	$ 45,359
7. Innisfil Hydro & customer contributed O/H TX relocates, replacements & upgrades	$ 191,707	$ 57,713
8. Innisfil Hydro & customer contributed U/G TX relocates,replacements & upgrades	$ 118,337	$ 81,653
9. Innisfil Hydro & customer contributed O/H secondary relocates,replacements & up	$ 24,342	$ 8,000
10. Innisfil Hydro & customer contributed U/G secondary relocates,replacements & up	$ 195,541	$ 132,968
11. Innisfil Hydro system supervisory & scada control	$ 12,571	
12. Economic evaluation	$ 217,359	
TOTAL	**$ 5,894,849**	**$ 425,526**
NET	**$ 5,469,323**	

Distribution	$ 5,168,634
General	$ 300,689
Total Engineering Capital	$ 5,469,323
IT & Metering	$ 660,050
WIP changes	$ -
Total IHDSL Capital Expenditures	**$ 6,129,373**
2013-2015 - 3 year average	**$ 7,030,833**

INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED

ENGINEERING BUDGET - 5 YR. FORECAST 2016

CAPITAL REQUESTS - DISTRIBUTION PLANT			Contributions	
Sandy Cove Acres U/G Cable Replacement and Rehab - North side, Phase 1	$	725,000		
Line Extension 27.6kV on Mapleview-Repoling from 20th & Mapleview W to St.	$	450,000		
Stroud DS 44kV/8320V Station Expansion 5 MVA Second Transformer	$	250,000		
Line Extension 3 Ph. Fdr 2 8320kV on Lockhart Rd.W/Yonge St. N to Maplevie	$	450,000		
Highway 400 & 10th Ln. 27.6 Crossing & Repoling from 10 S.R. to 5 S.R.	$	250,000		
44kV Line Rebuild Lockhart Road from 25 S.R. to Yonge St.	$	750,000		
Substandard transformer re-habs	$	217,534		
27.6 kV mechanized scada controlled load interrupting gang switches (3)	$	301,451		
44 kV mechanized scada controlled load Interrupting gang switches (2)	$	190,625		
2016 Pole replacement program	$	379,648		
Infrastructure replacements and betterments	$	251,111		
Recloser automation & replacements Innisfil DS - 4 year cycle replace	$	265,876		
U/G padmounted Transformer replacements and painting	$	94,895		
Third party utility relocates	$	81,054	$	39,323
CAPITAL REQUESTS - GENERAL PLANT				
Fleet tools	$	15,000		
Stores equipment	$	5,001		
Tools, shop and garage equipment	$	15,000		
Measurement and testing equipment	$	15,479		
27.6 kV Radio repeated fault indicators	$	45,722		
System supervisory	$	73,821		
Fleet vehicle replacement 1-2006 Ford 1/2 ton	$	45,000		
BASE - CAPITAL				
1. Land right & legal easements	$	-		
2. Station ancillary equipment replacement & improvement	$	5,503		
3. Innisfil Hydro & customer contributed poles, towers & fixture works	$	125,008	$	34,851
4. Innisfil Hydro & customer contributed O/H conductor works	$	117,512	$	27,758
5. Innisfil Hydro & customer contributed u/g duct installations & relocates	$	11,005	$	4,891
6. Innisfil Hydro & customer contributed primary cable installations & relocates	$	89,877	$	48,534
7. Innisfil Hydro & customer contributed O/H TX relocates, replacements & up	$	205,126	$	61,753
8. Innisfil Hydro & customer contributed U/G TX relocates,replacements & upg	$	126,621	$	87,369
9. Innisfil Hydro & customer contributed O/H secondary relocates,replacement	$	26,046	$	8,560
10. Innisfil Hydro & customer contributed U/G secondary relocates,replacement	$	209,229	$	142,276
11. Innisfil Hydro system supervisory & scada control	$	13,451	$	-
12. Economic evaluation	$	232,575	$	-
TOTAL	**$**	**6,034,169**	**$**	**455,313**
NET	**$**	**5,578,857**		

Distribution	$	5,350,382
General	$	228,474
Total Engineering Capital	$	5,578,857
IT & Metering	$	660,050
WIP changes	$	-
Total IHDSL Capital Expen	**$**	**6,238,907**

2013-2016 - 4 year average	**$**	**6,832,851**

INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED

ENGINEERING BUDGET - 5 YR. FORECAST 2017

CAPITAL REQUESTS - DISTRIBUTION PLANT			Contributions
Substandard transformer re-habs	$	231,674	
27.6 kV mechanized scada controlled load interrupting gang switches (3)	$	321,045	
44 kV mechanized scada controlled load Interrupting gang switches (2)	$	203,016	
2017 Pole replacement program	$	404,325	
Infrastructure replacements and betterments	$	267,433	
Recloser automation & replacements Innisfil DS - 4 year cycle replace	$	253,158	
U/G padmounted Transformer replacements and painting	$	101,063	
Third party utility relocates	$	86,323	$ 41,879
44KV reconductoring and poling 5sr N to Innisfil Beach Rd	$	784,000	
44KV Additional Subtransmission line extenstion of the Alliston 9M6 to 5th side roa	$	425,000	
44kV Betterment 25 Sideroad - Lockhart to Mapleview	$	294,496	
Sandy cove acres U/G cable replacement and rehab North side phase 2	$	750,000	
CAPITAL REQUESTS - GENERAL PLANT			
Double bucket truck fleet replacement 55 foot 1993 Ammador	$	325,000	
Fleet tools	$	12,500	
Stores equipment	$	5,326	
Tools, shop and garage equipment	$	10,000	
Measurement and testing equipment	$	16,485	
27.6 kV Radio repeated fault indicators	$	48,694	
System supervisory	$	78,619	
SCADA PME two (2) motorized switch gear install Crossroads	$	84,420	
Capacitor Intelilink to SCADA (2)	$	64,000	
BASE - CAPITAL			
1. Land right & legal easements	$	-	
2. Station ancillary equipment replacement & improvement	$	5,860	$ -
3. Innisfil Hydro & customer contributed poles, towers & fixture works	$	133,133	$ 37,116
4. Innisfil Hydro & customer contributed O/H conductor works	$	125,151	$ 29,562
5. Innisfil Hydro & customer contributed u/g duct installations & relocates	$	11,721	$ 5,209
6. Innisfil Hydro & customer contributed primary cable installations & relocates	$	95,719	$ 51,688
7. Innisfil Hydro & customer contributed O/H TX relocates, replacements & upgra	$	218,459	$ 65,766
8. Innisfil Hydro & customer contributed U/G TX relocates,replacements & upgra	$	134,851	$ 93,047
9. Innisfil Hydro & customer contributed O/H secondary relocates,replacements &	$	27,739	$ 9,116
10. Innisfil Hydro & customer contributed U/G secondary relocates,replacements &	$	222,829	$ 151,524
11. Innisfil Hydro system supervisory & scada control	$	14,325	$ -
12. Economic evaluation	$	247,692	$ -
TOTAL	$	6,004,057	**$ 484,909**
NET	**$**	**5,519,149**	

Distribution	$	5,184,779
General	$	334,370
Total Engineering C	$	5,519,149
IT/Metering	$	660,050
WIP changes	$	-
Total IHDSL Capita	$	6,179,199

2013-2017 - 5 year average **$ 6,702,121**

The following pending projects have been prioritized and listed to provide a pool of projects that can be inserted into the 5-Year Plan as priorities and circumstances change.

Priority	Rating	Project Description	Dollar Amount	
moved into	1	44kV Betterment 25 Sideroad - Lockhart to Mapleview	$ 294,496	used 2017
med	5	DS Oil re-inhibit treatment per/each	$ 26,000	
low	12	Capacitor Intelilink tp SCADA per/each	$ 21,400	
med	3	44KV reconductoring and poling 5sr N to Innisfil Beach Rd	$ 784,000	used 2017
high	2	Lockhart Road 44kV Pole Replacement - 10 Sideroad to Yonge Street	$ 512,000	
low	10	Stratallen Woods U/G conversion	$ 450,000	
low	11	Degrassi cove U/G conversion phase 1	$ 450,000	
med	4	44 kV line rebuild 5SR from Hwy. 89 north to 5th Line 9M2 tie	$ 700,000	
med	6	Parkview rear lot 1 phase relocate to street front	$ 275,000	
low	8	Line extension 27.6kV Lefroy DS 4th line -20th S.R east to 10th S.R	$ 980,000	
low	9	Line extension 27.6kV Lefroy DS to Bob Deugo10th S.R north to Innisfil Be	$ 520,000	
low	16	Alcona south 27.6 conversion	$ 400,000	
low	14	400 Corridor Voltage Conversion Thornton DS offload phase 1	$ 785,000	
low	13	Sandy cove acres U/G cable replacement and rehab North side phase 2	$ 750,000	used 2017
low	15	400 Corridor Voltage Conversion Thornton DS offload phase 2	$ 860,000	
med	7	Cookstown rebuild and infrastructure replacement	$ 550,000	

6. Financial Five Year Forecast Plan

The following Proforma Financial statements (2012 – 2017) have been attached in Appendix 1:

- Executive Summary
- Balance Sheet Budget
- P&L Budget
- Balance Sheet Analysis of Capital
- Cash from Operations Budget
- Rate Base, Debt, Equity and ROE Analysis

Assumptions:

- Rebasing rates are planned for May 1, 2013. Depending on cost increases beyond our control, a rebasing exercise can be accomplished before 2017, but there must be extra-ordinary and serious circumstances to justify.
- Projections are correlated with HR, IT and Engineering forecasts
- Expenses have utilized 3% growth and 5% for contract line crew costs per year
- Revenue growth is based on customer growth
- Load trends are based on the Town's economic development activity
- Innisfil Hydro is planning to move to a new location in 2013. The sale of the existing head office building is not projected until 2014.

Appendix 1

Executive Summary

	Forecast 2012	Projection 2013	2014	2015	2016	2017
Total Customers Y/E	15,020	15,219	15,666	16,360	17,193	18,052
Growth Numbers	194	199	448	693	833	860
Growth %	1.8%	1.3%	2.9%	4.4%	5.1%	5.0%
Total Revenues	8,308,637	9,034,486	10,054,245	10,004,370	10,499,329	11,813,853
Total Expenses	6,070,186	7,090,525	7,613,400	7,912,400	8,313,800	9,157,300
PILS Taxes	418,800	227,700	308,400	189,600	170,200	254,200
NIAT	1,076,989	648,005	877,806	539,544	484,379	723,558
Retained Earnings	5,199,868	5,222,873	5,475,679	5,390,223	5,249,602	5,348,160
Return S/H Equity	6.5%	3.9%	5.2%	3.2%	2.9%	4.3%
Capital Contributions	1,083,954	382,523	397,317	425,526	455,313	484,909
Dividends	625,000	625,000	625,000	625,000	625,000	625,000
Dividends yield	3.8%	3.8%	3.7%	3.7%	3.7%	3.7%
Change in cash	1,037,013	0	(1)	(0)	(0)	0
Debt	16,560,564	23,708,111	26,904,601	30,719,740	34,400,888	37,488,222
Change in debt	4,364,737	7,147,547	3,196,490	3,815,139	3,681,148	3,087,334
Debt ratio	49.9%	58.8%	61.4%	64.6%	67.4%	69.1%
Equity ratio	50.1%	41.2%	38.6%	35.4%	32.6%	30.9%

Customer Growth Assumptions

	Forecast 2012	Projection 2013	2014	2015	2016	2017
Total Customers Y/E	15,020	15,219	15,666	16,360	17,193	18,052
Residential Growth	192	194	421	652	781	805
GS < 50 Growth	4	5	24	38	49	51
GS > 50 Growth	(2)	(0)	2	3	4	4

Balance Sheet Budget

	Actual 2011	Forecast 2012	Projection 2013	2014	2015	2016	2017
Assets							
Cash	-	-	-	0	-	-	0
Short term investments	-	-	-	-	-	-	-
Receivables	2,952,862	3,000,000	3,150,000	3,200,000	3,250,000	3,300,000	3,350,000
Unbilled revenue	2,914,972	2,962,199	3,113,965	3,163,965	3,213,965	3,263,965	3,313,965
Inventory	428,004	440,000	450,000	463,500	477,400	491,700	506,500
Income taxes receivable	421,969	-	-	-	-	-	-
Future Income taxes-Current	22,000	22,000	22,000	22,000	22,000	22,000	22,000
Prepaids	300,372	315,000	325,000	334,800	344,800	355,100	365,800
Due from Interco	-	-	-	-	-	-	-
Notes due from IESL	-	-	-	-	-	-	-
Capital Assets	52,269,149	60,194,622	68,889,974	73,723,372	79,493,881	85,355,981	91,139,533
Accumulated Depreciation	(27,938,675)	(29,530,159)	(30,985,429)	(32,450,158)	(34,457,224)	(36,719,838)	(39,258,538)
Long Term Investment	21,721	21,721	21,721	21,721	21,721	21,721	21,721
Regulatory assets	2,563,947	768,619	389,117	504,157	503,497	502,837	502,177
Future Income Taxes	1,740,000	1,740,000	1,740,000	1,640,000	1,540,000	1,440,000	1,340,000
Total Assets	35,696,321	39,934,000	47,116,346	50,623,357	54,410,041	58,033,467	61,303,158
Liabilities							
Cash	1,037,013	0	0	-	0	0	-
Current portion of LTD	5,026,316	1,211,243	1,306,770	1,401,285	364,039	373,103	381,460
Payables	4,372,280	4,773,375	4,893,687	4,947,900	5,002,500	5,058,100	5,114,200
Customer credit bal & deposits	648,368	650,000	620,000	608,000	596,000	584,000	572,000
Income taxes payable	-	120,000	130,000	131,000	132,000	133,000	134,000
Due to related party	97,871	70,100	48,900	25,500	1,000	1,500	2,000
Future Taxes	-	-	-	-	-	-	-
Customer & retailer deposits	205,196	215,000	210,000	206,000	202,000	198,000	194,000
Regulatory Liabilities	983,818	98,625	-	-	-	-	-
Long term debt	7,169,511	15,349,321	22,401,341	25,503,316	30,355,701	34,027,785	37,106,762
Total Liabilities	19,540,376	22,487,664	29,610,698	32,823,001	36,653,240	40,375,488	43,504,422
Shareholder Equity							
Capital Stock	10,852,444	10,852,444	10,852,444	10,852,444	10,852,444	10,852,444	10,852,444
Development chgs	555,621	555,621	555,621	555,621	555,621	555,621	555,621
Retained Earnings	4,747,880	6,038,267	6,097,581	6,392,287	6,348,731	6,249,910	6,390,668
Total Shareholder Equity	16,155,945	17,446,336	17,505,649	17,800,357	17,756,801	17,657,979	17,798,737
Total Liabilities and Equity	35,696,321	39,934,000	47,116,347	50,623,358	54,410,041	58,033,467	61,303,159

P&L Budget

	Actual 2011	Forecast 2012	Projection 2013	2014	2015	2016	2017
Energy Revenue	21,570,056	24,387,689	24,220,825	25,407,600	27,033,700	28,763,900	30,604,800
Energy Costs	(21,570,056)	(24,387,689)	(24,220,825)	(25,407,600)	(27,033,700)	(28,763,900)	(30,604,800)
Distribution Revenue	7,633,882	8,992,133	8,530,871	9,038,950	9,496,900	9,983,650	11,292,100
Other Revenue	544,272	444,825	501,915	1,021,195	513,170	521,379	527,953
Total Gross Margin & other revenue	8,178,154	9,436,958	9,032,786	10,060,145	10,010,070	10,505,029	11,820,053
Operating Expenses:							
Distribution Ops & Maintenance	1,476,314	1,760,995	2,137,512	2,190,700	2,245,300	2,301,400	2,600,300
Billing and Collecting	925,296	955,500	1,106,020	1,133,700	1,162,000	1,191,100	1,220,800
Administration	1,806,010	1,931,265	2,235,040	2,391,200	2,348,400	2,406,900	2,666,600
Depreciation	1,894,236	1,386,248	1,561,144	1,847,000	2,105,800	2,363,600	2,618,700
Total Operating Expenses	**6,101,856**	**6,034,008**	**7,039,716**	**7,562,600**	**7,861,500**	**8,263,000**	**9,106,400**
Earnings from Operations	2,076,298	3,402,950	1,993,070	2,497,545	2,148,570	2,242,029	2,713,653
Interest on Long term debt	672,043	742,662	1,068,256	1,254,639	1,362,826	1,530,950	1,678,795
Earnings before Income Taxes	1,404,256	2,660,288	924,813	1,242,906	785,744	711,079	1,034,858
Income Taxes	293,400	744,900	240,500	323,200	204,300	184,900	269,100
Net Earnings	1,110,856	1,915,388	684,313	919,706	581,444	526,179	765,758
ROE	6.9%	11.0%	3.9%	5.2%	3.3%	3.0%	4.3%
Retained Earnings, Beginning	4,262,023	4,747,880	6,038,267	6,097,581	6,392,287	6,348,731	6,249,910
Dividends	(625,000)	(625,000)	(625,000)	(625,000)	(625,000)	(625,000)	(625,000)
Change in Future Income Tax	-	-	-	-	-	-	-
Retained Earnings, Ending	4,747,880	6,038,267	6,097,581	6,392,287	6,348,731	6,249,910	6,390,668

Balance Sheet Analysis of Capital

Distribution and General Plant	Actual 2011	Forecast 2012	Projection 2013	2014	2015	2016	2017
Capital Asset Opening Balance	50,156,165	52,269,149	60,194,622	68,889,974	73,723,372	79,493,881	85,355,981
Purchases	4,415,727	9,362,689	9,403,375	6,339,591	6,554,899	6,694,220	6,664,108
WIP changes	110,615	(35,616)	-	-	-	-	-
Capital Contributions	(521,407)	(1,083,954)	(382,523)	(397,317)	(425,526)	(455,313)	(484,909)
Adjustments	85,160	-	-	-	-	-	-
Disposals	(1,977,111)	(317,646)	(325,500)	(1,108,876)	(358,864)	(376,807)	(395,647)
Capital Asset Ending Balance	52,269,149	60,194,622	68,889,974	73,723,372	79,493,881	85,355,981	91,139,533
Accum Deprec Opening Balance	(27,555,405)	(27,938,675)	(29,530,159)	(30,985,429)	(32,450,158)	(34,457,224)	(36,719,838)
Current year depreciation	(1,894,236)	(1,386,248)	(1,561,144)	(1,847,000)	(2,105,800)	(2,363,600)	(2,618,700)
Adjustments-'12 SMI trueup je	(16,884)	(354,606)	-	-	-	-	-
Disposals	1,716,823	266,170	276,675	572,071	305,034	320,286	336,300
Deduct:Truck Depr realloc rolling stock	(220,718)	(159,800)	(170,800)	(189,800)	(206,300)	(219,300)	(256,300)
Add:Stranded Meter depr from DVA acct	31,745	43,000	-	-	-	-	-
Capital Asset Ending Balance	(27,938,675)	(29,530,159)	(30,985,429)	(32,450,158)	(34,457,224)	(36,719,838)	(39,258,538)
Net Book Value	24,330,474	30,664,463	37,904,545	41,273,214	45,036,658	48,636,144	51,880,995
Excess of Purchases over depreciation	2,000,084	6,892,487	7,459,708	4,095,274	4,023,573	3,875,307	3,560,499
NBV of Disposals	260,288	51,476	48,825	536,805	53,830	56,521	59,347

Cash from Operations Budget

	Actual	Forecast	Projection				
Operating	2011	2012	2013	2014	2015	2016	2017
Net Earnings	1,110,856	1,915,388	684,313	919,706	581,444	526,179	765,758
Future income taxes	(122,000)	-	-	100,000	100,000	100,000	100,000
(Gain)Loss on disposal	126,618	51,476	48,825	(463,195)	53,830	56,521	59,347
Depreciation	2,081,606	1,857,654	1,731,944	2,036,800	2,312,100	2,582,900	2,875,000
	3,197,080	3,824,518	2,465,083	2,593,311	3,047,374	3,265,600	3,800,105
Customer Deposits	(145,812)	9,804	(5,000)	(4,000)	(4,000)	(4,000)	(4,000)
Change in non-cash oper working cap	186,711	795,936	(242,654)	(103,487)	(104,800)	(79,500)	(79,900)
	3,237,979	4,630,258	2,217,429	2,485,824	2,938,574	3,182,100	3,716,205
Financing							
Capital contributions	521,407	1,083,954	382,523	397,317	425,526	455,313	484,909
Proceeds from property sale	-	-	-	1,000,000	-	-	-
Changes in debt	3,217,182	4,364,737	7,147,547	3,196,490	3,815,139	3,681,148	3,087,334
Loan to related party	-	-	-	-	-	-	-
	3,738,589	5,448,691	7,530,070	4,593,807	4,240,665	4,136,461	3,572,243
		2,895,458					
Investing							
Net additions to ST investments	-	-	-	-	-	-	-
Net additions to property and equip	(4,459,345)	(9,327,073)	(9,403,375)	(6,339,591)	(6,554,899)	(6,694,220)	(6,664,108)
Net additions to regulatory liabilities	191,954	(885,193)	(98,625)	-	-	-	-
Net additions to regulatory assets	403,930	1,795,328	379,502	(115,040)	660	660	660
Net additions to LT investments	-	-	-	-	-	-	-
	(3,863,461)	(8,416,937)	(9,122,498)	(6,454,631)	(6,554,239)	(6,693,560)	(6,663,448)
Dividends	(625,000)	(625,000)	(625,000)	(625,000)	(625,000)	(625,000)	(625,000)
S/H Equity-Development Chges	-	-	-	-	-	-	-
Increase(Decrease) in Cash	2,488,107	1,037,013	(0)	0	(0)	(0)	0
Cash, beginning of year	(3,525,119)	(1,037,013)	(0)	(0)	0	(0)	(0)
Cash, end of year	(1,037,013)	(0)	(0)	0	(0)	(0)	0

Innisfil Hydro - Rate Base, Debt, Equity and ROE analysis

	COS 2009	2011	2012	COS 2013	2014	2015	2016	COS 2017	2018	2019	2020	COS 2021	2022	2023	2024	COS 2025	2026	2027	2028	COS 2029	2030	2031
Deemed ROE $	701	895	914	1,332	1,497	1,656	1,816	1,965	2,104	2,239	2,371	2,499	2,624	2,745	3,043	3,333	3,438	3,538	3,636	3,730	3,820	3,907
Deemed Interest $	903	1,153	1,178	878	987	1,092	1,197	1,561	1,671	1,779	1,883	1,985	2,085	2,181	2,417	2,648	2,731	2,811	2,888	2,963	3,035	3,104
Return on ratebase if COS every year	1,604	2,048	2,092	2,210	2,484	2,748	3,013	3,526	3,775	4,018	4,254	4,485	4,709	4,926	5,460	5,981	6,168	6,349	6,524	6,692	6,855	7,011
Deemed debt if COS every year	13,119	16,755	17,113	21,906	24,627	27,243	29,864	32,320	34,603	36,827	38,995	41,106	43,159	45,155	50,047	54,825	56,540	58,197	59,798	61,343	62,831	64,262
Debt per financials	13,722	14,203	18,624	27,046	29,747	32,401	35,007	40,841	46,475	51,909	57,143	61,643	65,942	70,042	103,622	105,718	107,613	109,309	110,804	111,704	112,403	112,903
Debt Under(Over) leverage	(603)	2,552	(1,511)	(5,140)	(5,120)	(5,158)	(5,144)	(8,521)	(11,872)	(15,082)	(18,148)	(20,537)	(22,783)	(24,887)	(53,575)	(50,892)	(51,074)	(51,111)	(51,006)	(50,361)	(49,573)	(48,640)
Actual debt ratio	61.1%	47.2%	54.0%	62.0%	63.2%	64.3%	65.2%	67.1%	68.5%	69.6%	70.4%	70.4%	70.3%	70.2%	76.7%	75.5%	74.4%	73.4%	72.3%	71.1%	69.8%	68.6%
Actual equity ratio	38.9%	52.8%	46.0%	38.0%	36.8%	35.7%	34.8%	32.9%	31.5%	30.4%	29.6%	29.6%	29.7%	29.8%	23.3%	24.5%	25.6%	26.6%	27.7%	28.9%	30.2%	31.4%
Deemed interest-per IHDSL COS filing	903	903	903	878	878	878	878	1,561	1,561	1,561	1,561	1,985	1,985	1,985	1,985	2,648	2,648	2,648	2,648	2,963	2,963	2,963
Forecasted interest-per annual f/s	945	699	734	1,084	1,391	1,576	1,691	1,973	2,245	2,507	2,760	2,977	3,185	3,383	5,005	5,106	5,198	5,280	5,352	5,395	5,429	5,453
Interest Over(Under) reovery	(42)	204	169	(206)	(513)	(698)	(813)	(412)	(684)	(946)	(1,199)	(992)	(1,200)	(1,398)	(3,020)	(2,458)	(2,550)	(2,632)	(2,704)	(2,432)	(2,466)	(2,490)
Deemed ROE if COS every year	733	895	914	1,332	1,497	1,656	1,816	1,965	2,104	2,239	2,371	2,499	2,624	2,745	3,043	3,333	3,438	3,538	3,636	3,730	3,820	3,907
Forecasted ROE-per annual f/s	733	1,004	617	1,332	1,332	1,332	1,332	1,965	1,965	1,965	1,965	2,499	2,499	2,499	2,499	3,333	3,333	3,333	3,333	3,730	3,730	3,730
ROE Under(Over) recovery	-	(109)	296	-	165	324	484	-	139	274	406	-	125	246	544	-	104	205	302	-	90	178
Forecasted ROE-per annual f/s		1,004	617	1,332	1,332	1,332	1,332	1,965	1,965	1,965	1,965	2,499	2,499	2,499	2,499	3,333	3,333	3,333	3,333	3,730	3,730	3,730
Dividends		625	625	625	625	625	625	625	625	625	625	625	625	625	625	625	625	625	625	625	625	625
Retained Earnings		4,472	4,464	5,171	5,878	6,585	7,292	8,632	9,972	11,312	12,652	14,526	16,401	18,275	20,149	22,857	25,566	28,274	30,983	34,087	37,192	40,297
Forecasted Equity	8,746	15,880	15,872	16,579	17,286	17,993	18,700	20,040	21,380	22,720	24,060	25,934	27,809	29,683	31,557	34,265	36,974	39,682	42,391	45,495	48,600	51,705
Opening Net Fixed Assets	17,840	22,601	25,578	30,470	34,669	38,868	43,067	47,266	50,978	54,590	58,102	61,514	64,826	68,038	71,150	84,002	86,729	89,356	91,883	94,310	96,637	98,864
Annual Additions	3,102	4,919	5,993	6,274	6,274	6,274	6,274	6,250	6,250	6,250	6,250	6,250	6,250	6,250	16,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
Annual Depreciation	(1,918)	(1,942)	(1,101)	(2,075)	(2,075)	(2,075)	(2,075)	(2,538)	(2,638)	(2,738)	(2,838)	(2,938)	(3,038)	(3,138)	(3,398)	(3,523)	(3,623)	(3,723)	(3,823)	(3,923)	(4,023)	(4,123)
Ending Net Fixed Assets	19,024	25,578	30,470	34,669	38,868	43,067	47,266	50,978	54,590	58,102	61,514	64,826	68,038	71,150	84,002	86,729	89,356	91,883	94,310	96,637	98,864	100,991
2 Year Average Net Fixed Assets	18,431	24,090	24,747	32,570	36,769	40,968	45,167	49,122	52,784	56,346	59,808	63,170	66,432	69,594	77,576	85,366	88,043	90,620	93,097	95,474	97,751	99,928
Working capital allowance	3,434	3,836	3,775	3,941	4,276	4,438	4,606	4,744	4,887	5,033	5,184	5,340	5,500	5,665	5,835	6,010	6,190	6,376	6,567	6,764	6,967	7,176
Rate Base	21,865	27,926	28,522	36,511	41,045	45,406	49,773	53,866	57,671	61,379	64,992	68,510	71,932	75,259	83,411	91,376	94,233	96,996	99,664	102,238	104,718	107,104
Deemed debt rate LT	7.28%	7.28%	7.28%	4.01%	4.01%	4.01%	4.01%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%
Deemed debt rate ST	1.33%	1.33%	1.33%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Deemed ROE	8.01%	8.01%	8.01%	9.12%	9.12%	9.12%	9.12%	9.12%	9.12%	9.12%	9.12%	9.12%	9.12%	9.12%	9.12%	9.12%	9.12%	9.12%	9.12%	9.12%	9.12%	9.12%
Deemed debt ratio LT	56.00%	56.00%	56.00%	56.00%	56.00%	56.00%	56.00%	56.00%	56.00%	56.00%	56.00%	56.00%	56.00%	56.00%	56.00%	56.00%	56.00%	56.00%	56.00%	56.00%	56.00%	56.00%
Deemed debt ratio ST	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Deemed equity ratio	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%

Working Capital Allowance	2009	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Cost of power	18,957	21,117	21,117	22,100	24,211	25,161	26,149	26,933	27,741	28,574	29,431	30,314	31,223	32,160	33,125	34,119	35,142	36,196	37,282	38,401	39,553	40,739
Expenses	3,933	4,457	4,051	4,173	4,298	4,427	4,559	4,696	4,837	4,982	5,132	5,286	5,444	5,608	5,776	5,949	6,127	6,311	6,501	6,696	6,897	7,103
Total	22,890	25,574	25,168	26,273	28,509	29,588	30,708	31,630	32,579	33,556	34,563	35,599	36,667	37,767	38,901	40,068	41,270	42,508	43,783	45,096	46,449	47,843
Working Capital Allow @ 15%	3,434	3,836	3,775	3,941	4,276	4,438	4,606	4,744	4,887	5,033	5,184	5,340	5,500	5,665	5,835	6,010	6,190	6,376	6,567	6,764	6,967	7,176
Debt																						
Debt-pre 2013	12,807	14,203	18,224	17,114	15,911	14,619	14,369	14,119	13,869	13,619	13,369	13,119	12,869	12,619	12,369	12,119	11,869	11,619	11,369	11,119	10,869	10,619
Debt-2013 and fwd	-	-	-	9,532	13,436	17,382	20,238	26,322	32,206	37,890	43,374	48,124	52,673	57,023	80,853	83,599	86,144	88,490	90,635	92,185	93,534	94,684
Debt-Transmission tower	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10,000	9,600	9,200	8,800	8,400	8,000	7,600	7,200
Line of credit	915	-	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
Total Debt	13,722	14,203	18,624	27,046	29,747	32,401	35,007	40,841	46,475	51,909	57,143	61,643	65,942	70,042	103,622	105,718	107,613	109,309	110,804	111,704	112,403	112,903
Weighted average interest rate	6.89%	4.92%	3.94%	4.01%	4.68%	4.86%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%	4.83%
Cash from ops							(3,492)	(2,372)	(2,272)	(2,172)	(2,072)	(1,438)	(1,338)	(1,238)	(10,978)	(19)	81	181	281	778	878	978

Assumptions

1) COS filing every 4 years starting in 2009

Appendix 2

20 Year Innisfil Hydro Supply Analysis (2011-2031)

G. Shaparew Aug 27, 2012

Normal Load growth at 2kW per population
Load growth minus 2.5 MW conservation target

One New 44 kV Feeder installed 9M2

One New 44 kV Feeder Aliston TS

OPTION 1

One New 44 kV Feeder Required

One New 44 kV Feeder Required

One New 44 kV Feeder Required

One New 44 kV Feeder Required

OPTION 2

92 MW Requred
Will Require 4 - 44 kV feeders & 7 - 13.3MVA DSs or
a 230kV - 27.6kV TS

Available Supply From Hydro One (MW)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Feeder Capacity	63	63	63	63	63	88	88	88	88	88	88	88	88	113	113	113	138	138	138	163	163	163	188	188	188	188	213	213
Total Load MW	54	63	48	49	49	50	67	67	68	69	72	77	83	90	99	109	118	127	137	146	155	163	170	178	185	192	199	201
2.5MW reduction						48	67	65	66	67	70	74	80	87	96	106	115	125	134	143	153	161	168	175	182	189	196	198
DS Cap MW	68	68	68	68	75	75	75	75	75	75	88	101	101	101	101	124	124	124	137	150	163	163	180	180	180	193	193	206
					Bob Deugo DS						New Lefroy DS	New BBP DS				DS			DS	DS	DS		DS			DS		DS

Projected Load in Innisfil (MW)

56K Population

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
OP MW	53.7	62.7	48.2	49	65	66	67	67	68	69	71	74	76	78	80	82	85	88	92	95	98	102	103	105	107	109	111	114
With BBP MW	53.7	62.7	48.2	49	65	66	67	67	68	69	72	76	80	82	86	90	94	97	100	104	107	110	112	115	117	119	121	123
population	30.5	30.9	32.4	32007	32515	32932	33277	33608	34170	34748	35467	36796	38132	39046	39946	40926	42566	44206	45846	47486	49126	50766	51250	52410	53570	54730	55745	56760
Units		129	203	353	175	144	119	114	194	199	248	459	461	315	310	338	566	566	566	566	566	566	400	400	400	400	350	350
Pop Increase		400	400	1024	508	418	345	331	563	577	719	1330	1336	914	900	980	1640	1640	1640	1640	1640	1640	1160	1160	1160	1160	1015	1015

39K Population

Barrie Lands MW									0	0	0	0.2	1.2	3.2	7.2	12.2	18.2	24.2	30.2	36.2	42.2	48.2	53.2	58.2	63	67.8	72.6	77.4
Population									0	0	0	100	600	1600	3600	6100	9100	12100	15100	18100	21100	24100	26600	29100	31500	33900	36300	38700
Units									0	0	0	34	172	345	690	862	1034	1034	1034	1034	1034	1034	862	862	828	828	828	828
Pop Increase									0	0	0	100	500	1000	2000	2500	3000	3000	3000	3000	3000	3000	2500	2500	2400	2400	2400	2400

BBP Requirements (MW)									0.00	0.00	1.08	2.16	3.24	4.32	6.48	8.64	8.64	8.64	8.64	8.64	8.64	8.64	8.64	8.64	8.64	8.64	8.64	8.64
BBP Units											200	400	600	800	1200	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600
BBP Units Add									0	0	200	200	200	200	400	400	0	0	0	0			0	0				

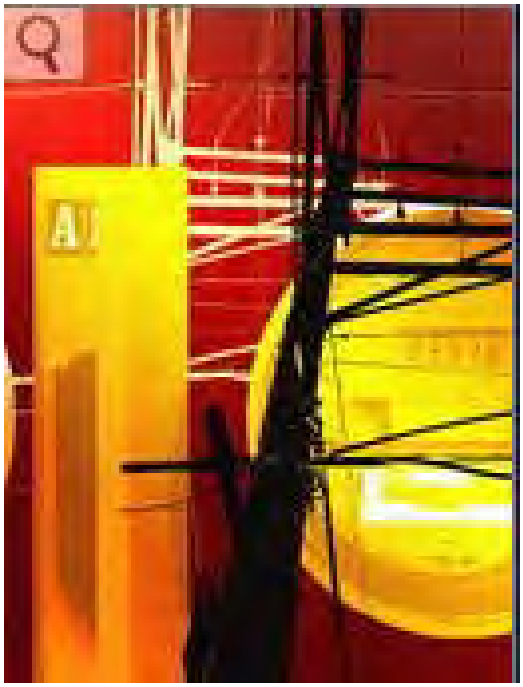
Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Customers EOY	13,542	13,703	13,832	14,035	14,388	14,563	14,707	14,826	15020	15219	15666	16360	17193	18052	19452	21052	22652	24252	25852	27452	29052	30652	31914	33176	34404	35631	36809	37986
New customers		129	203	353	175	144	119	114	194	199	448	693	833	860	1400	1600	1600	1600	1600	1600	1600	1600	1262	1262	1228	1228	1178	1178
% customer growth		0.9%	1.5%	2.5%	1.2%	1.0%	0.8%	0.8%	1.3%	1.3%	2.9%	4.2%	4.8%	4.8%	7.2%	7.6%	7.1%	6.6%	6.2%	5.8%	5.5%	5.2%	4.0%	3.8%	3.6%	3.4%	3.2%	3.1%

Appendix 3

Innisfil Hydro Distribution Systems Limited

Asset Management Plan

2012



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Appendix C, DSC Minimum Maintenance Standards

Background

The Innisfil Hydro Electric Commission was originally formed in January 1991 and in July 1993, the distribution assets were purchased from Ontario Hydro for the service area expansion. 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, defined as the Town of Innisfil as of January 1, 1994.

As of January 1, 2009, 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 hired five “in-house” Linemen in 2010 that perform daily service work requirements. All other associated Line construction projects 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 34 full time staff. The site consists of a Customer Service building, an Engineering and Finance building, a Warehouse building and two old school portables situated on approximately 3.6 acres.

Following the aftermath of the *Oak Ridges Moraine Protection Act 2001*, 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).

Utilizing growth projections from all available data, the following population projections comprises the parameters for growth:

- Innisfil population in 2031 56,000
- New Barrie land population in 2031 39,000
- Big Bay Point development 1,600 units + commercial load

Both population and employment is projected to increase by more than 100% within the next 20 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 be contrary to the Distribution System Code.

AESI Acumen Engineering Solutions was engaged in 2012 to review, provide commentary and make recommendations on the Asset Management Plan. Their report is attached in Appendix 7. Innisfil Hydro staff have implemented all reasonable recommendations from the AESI report into the 2012 Asset Management Plan.

2012 Programs whether O&M or Capital are generally prioritized as follows:

1. Health & Safety
2. Legislative
3. Growth
4. Reliability

*** 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 endeavours to meet the all of the minimum maintenance standards in DSC Appendix C. Reductions in Operations or Maintenance funding may 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.

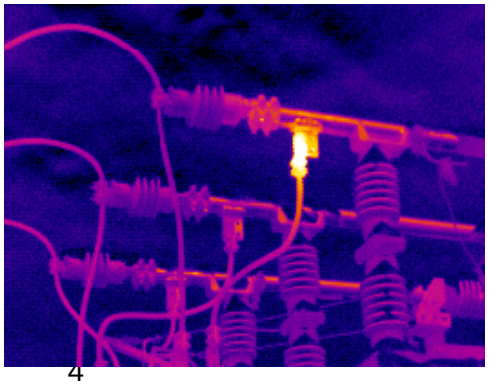
Trees contacting energized lines have the ability to inflict the following:

- 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 within a three year time frame.

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 cost for tree trimming has been budgeted in account 5135.

3.2 Infra-red Scanning



Electrical energy forces 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 pictures (above) shows 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 high voltage assets on a three year cycle as follows:

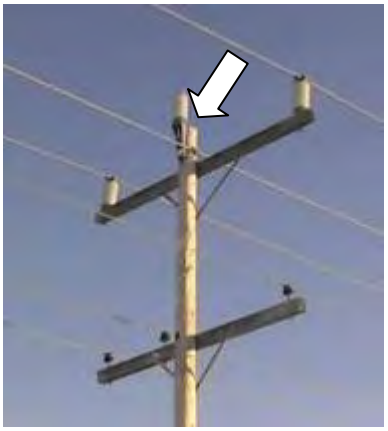
Year 1. All overhead primary voltage 3 phase and single phase lines (44kV, 27.6kV, 8.32kV) including Distribution Stations.

Year 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.

Year 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 cost for infra-red scanning has been budgeted in accounts 5020 & 5045.

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

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 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. Electrical system problems 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 perform a physical inspection at 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 become loose. With weather elements such as wind and ice loading, hardware can eventually 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 $56,000.00 and has not been budgeted for in 2013. 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 has only Operation's staff on standby duty after normal working hours. Engineering and Operation's staff perform line patrol while driving to and from work on a daily basis. The Town is divided into eleven quadrants and staff keep a log of the quadrants and dates that receive line patrol.

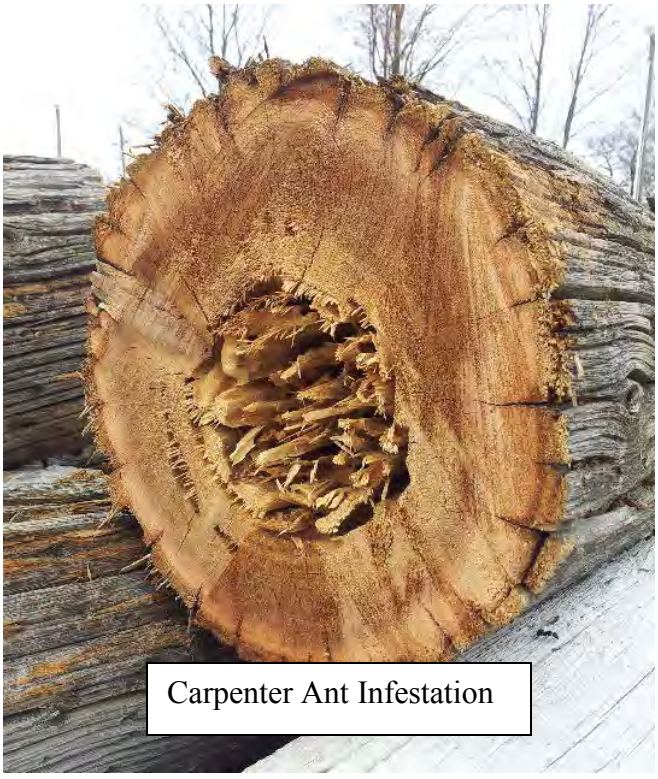
3.4 Poles

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' in length. These pole species involve creosote, chromium copper arsenate or pentachlorophenol treatment to extend the life of the wood. There are no steel or composite poles that are in service in Innisfil. Two concrete poles are in service where feeder 9M6 enters Innisfil. These two concrete poles were installed in 2009 to facilitate installations where guying was not possible.

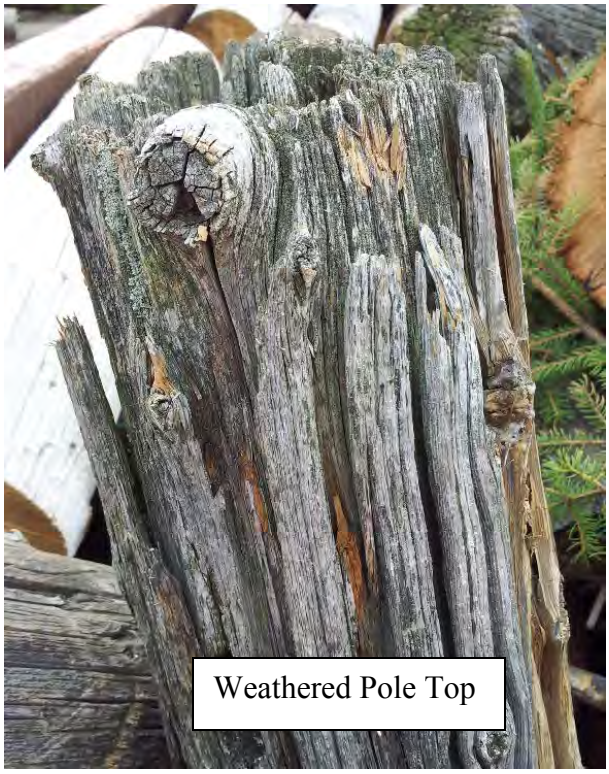
The majority of wood pole deterioration occurs at the pole butt, basically where the pole enters the ground. The amount of pole below the surface is 2 feet plus 10% of the pole height. It is the area flush with the ground that receives the greatest impact of moisture and oxygen that enables the rotting 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 pole replacement is scheduled as required.

While pole testing at grade identifies the need of pole replacements due to ground level pole deterioration. Poles also require replacement as a result of carpenter ant / termite damage and age related weathering above grade. Example of these two pole deficiencies are shown below.



Carpenter Ant Infestation



Weathered Pole Top

Historically, a pole replacement rate of approximately4% has been experienced and is budgeted for within the capital budget. However, an approximate 200-215 of the tested poles per year receive comments back to Innisfil Hydro from the pole testers indicating

deficiencies. Items such as slack or loose guy wires, guy strain insulators pulled apart or broken, guy guards out of position or missing, loose grounding connections and missing nomenclature are a few examples. A maintenance program has not been budgeted before in the past, however with an Annual Pole Maintenance Program, Innisfil Hydro would be able to address the issues raised by our contractor and remediate potential hazards to the public and staff. The annual maintenance cost of **$13,440.00** has been included in the **5120** account in the 2013 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 Geographical Information System (GIS). An increase to a six year pole testing program cycle will increase pole testing costs by over 33%. The typical cost for pole testing utilizing an eight year pole testing program cycle is $30,000.

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 straighten poles that are currently leaning. This issue will always be present with existing poles. 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 visually displeasing to look at, the potential for more dangerous situations may 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 2013.

Pole Replacements are undertaken for the following different reasons:

- Pole decomposition or 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.

Poles are replaced to current ESA requirements. With an approximate 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, capital growth and project requirements:

	2012	2013	2014	2015	2016	2017
Total Count	10,120	10,150	10,180	10,210	10,240	10,270
Total Replacement	215	215	215	215	220	220
Additional	30	30	30	30	30	30

Poles are replaced as required to maximize the health and safety of the public, system reliability and the ability to connect new customers.

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 switches (cut-outs) accept different sizes of fuses, which are used for the protection of lines, equipment or transformers from main feeder amperages. Fused cut-outs are inspected during the infra-red scanning process. Fused cut-outs 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 related fused cut-outs may be replaced as an act of due diligence. Failure to do so will not only decrease reliability and the safety of operational personnel would be compromised.

Load break and air break 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 perform switch maintenance on one quarter of all airbreak and loadbreak switches on an annual basis. The cost to perform three phase switch maintenance has been budgeted in account 5125 which does not include repair parts.

There are numerous in-line switches and mid span openers (MSOs) on the 44kV, 27.6kV and 8.32kV system. These are single phase switches or mid span openers that

can be grouped together on 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 and are replaced as required. Failure to do so will not only decrease reliability, the safety of operational personnel would be compromised. These devices have traditionally received proactive maintenance via the infra red scanning process. An actual physical inspection would require three crew hours to perform in-line switch or MSO maintenance which would require an extra $$12,900 of internal labour annually to implement a cycle program. This new additional amount has been budgeted for in the 5125 account of the 2013 Maintenance Budget.

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;
- Systemic failures involving a particular manufacturer or style.

The following switch addition and replacement schedule has been incorporated to deal with capital requirements:

Disconnect Cutouts Single & Three Phase						
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Total Count	384	399	415	431	447	463
Replacement	30	10	10	10	10	10
Additional	15	16	16	16	16	16
These cutouts include disconnect devices on our distribution infrastructure, but exclude transformer protection fuses.						

Air Break and Load Break Three Phase Switches						
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Total Count	57	65	73	81	89	97
Replacement	2	3	3	3	3	3
Additional *	8	8	8	8	8	8
Includes manual and automatic switches, on both our subtransmission and distribution system. Types include SCADA-Mate's, Alduti-Rupter's, reclosers (used as **switches**), and manual gang switches						
* numbers based on 5 yr plan, pending Green Energy plan approval						

In-Line Switches & MSOs						
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Total Count	336	338	340	342	344	346
Replacement	8	8	8	10	10	10
Additional	2	2	2	2	2	2

3.6 Reclosers

Recloser inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. IHDSL currently has eight (8) three-phase reclosers and 82 single-phase reclosers installed and fully operational on its distribution infrastructure. While all eight (8) three-phase reclosers are radio controlled and serve as circuit breakers inside three (3) of our Distribution Stations (DS), 45 single phase hydraulic reclosers serve as protective devices for station transformers inside the other six (6) of our DS'. The remaining 37 single-phase

hydraulic reclosers are installed on our distribution lines in Innisfil Hydro's system. The list is kept in an EXCEL directory by the Engineering and Operations Clerk. 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 or vacuum chamber 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 reclosers are inspected and rebuilt once ever 4 years. They are also inspected by the infra-red process. Reclosers that are damaged, will be replaced as required. The cost for rebuilding the reclosures is capitalized and the cost for maintaining reclosers is in account 5125.

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. The cost for inspecting voltage regulators is in account 5016. There are no voltage regulators budgeted for replacement in 2013.

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 3071 overhead and pad mounted transformers in its distribution system. The transformer list is kept in the Northstar Billing system. Innisfil Hydro does not have any transformers in confined spaces or below grade.

Transformers are able to transform 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

For Innisfil Hydro to have internal staff or external contractors either climb poles or set-up bucket trucks to inspect transformers up close, it is estimated that the cost of $60 per overhead transformer would be required. This translates into an annual cost increase of $45,000. This has not been budgeted for in 2013.

The annual 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, potential oil leakage or internal/external problems. The following overhead transformer addition and replacement schedule has been incorporated to deal with capital requirements:

Overhead Transformers

	2012	2013	2014	2015	2016	2017
Total Count	2,145	2,156	2,168	2,183	2,203	2,223
Replacement	26	26	27	28	28	28
Additional	11	12	15	20	20	20

The cost for infra-red scanning overhead transformers has been budgeted in account 5020 & 5045.

3.9.1 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. The cost for inspecting capacitors has been budgeted in account 5125. There are no plans to replace any capacitors within the next five year horizon.

Fault Indicators

The installation and use of overhead radio controlled fault indicators has been deployed since 1996. These units send radio signals to the Innisfil Hydro Supervisory Control and Data Acquisition (SCADA) system when fault currents have been detected. They assist in finding a problem section of line and for sectionalizing damaged sections of high voltage lines. Lowering System Average Interruption Duration Index (SAIDI) 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 forty sets of indicators scattered over Innisfil Hydro territory an expected cost of $12,100 would be needed on a yearly basis to make this happen on an annual basis. This new additional amount has been budgeted for in the **5125** account of the 2013 budget.

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 $9,000 of crew labour to complete. This has not been budgeted for in 2013 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 49 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 whereby there are no high voltage connections 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. The cost for infra-red inspecting switching cubicles has been budgeted in account 5020 & 5045. Switch Gears are exposed to a variety of elements which can cause potential public safety hazards, equipment deterioration and operational challenges. In addition to infra-red testing , a more in-depth maintenance program will create an opportunity to lubricate and operate infrequently used load break elbows and switches; repair and/or replace corroded connectors caused by acidic soil conditions and standing water; identify and correct any abnormal soil infiltration; inspect, repair or replace transformer grounding; re-fresh deteriorated nomenclature and identify any damage to the outside of the equipment caused by pedestrian, vehicular and municipal maintenance traffic. An annual maintenance cost of **$49,780.00** under the heading of Underground Transformer and Switch Gear Maintenance has been included in the **5161** account of the 2013 budget.

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 off 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 cost for underground cable locating has been budgeted in accounts 5070, 5075, 5040 & 5045.

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. Pad mounted transformers have their lids opened and are 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. Elbows or cable terminators are nomenclatured to the connecting switch, transformer or switching 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. The cost for infra-red inspecting underground elbows and terminators has been budgeted in account 5020 & 5045. In addition to infra-red testing , a more in-depth maintenance program will create an opportunity to lubricate and operate infrequently used load break elbows and switches; repair and/or replace corroded connectors caused by acidic soil conditions and standing water; identify and correct any abnormal soil infiltration; inspect, repair or replace transformer grounding; re-fresh deteriorated nomenclature and identify any damage to the outside of the equipment caused by pedestrian, vehicular and municipal maintenance traffic. An annual maintenance cost of **$49,780.00** under the heading of Underground Transformer and Switch Gear Maintenance has been included in the **5161** account of the 2013 budget.

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 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. The cost for inspecting underground transformers has been budgeted in the infra-red scanning budget. The cost for infra-red scanning underground transformers has been budgeted in account 5020 & 5045. Underground Transformers are exposed to a variety of elements which can cause potential public safety hazards, equipment deterioration and operational challenges. In addition to infra-red testing , a more in-depth maintenance program will create an opportunity to lubricate and operate infrequently used load break elbows and switches; repair and/or replace corroded connectors caused by acidic soil conditions and standing water; identify and correct any abnormal soil infiltration; inspect, repair or replace transformer grounding; re-fresh deteriorated nomenclature and identify any damage to the outside of the equipment caused by pedestrian, vehicular and municipal maintenance traffic. An annual maintenance cost of **$49,780.00** under the heading of Underground Transformer and Switch Gear Maintenance has been included in the **5161** account of the 2013 budget.

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:

Pad Mounted Transformers

	2012	2013	2014	2015	2016	2017
Total Count	1,030	1,105	1,190	1,275	1,360	1,445
Replacement	8	9	8	9	9	9
Additional	75	85	85	85	85	85

All additional transformers are required to meet load growth and load demand.

4.5 Underground 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. 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 cost for maintaining and inspecting underground primary services has been budgeted in account 5150.

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.

Approximately 30 spans of secondary buss replacement have been budgeted to replace in 2013. 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. Secondary services with a premature failure rate are repaired or replaced as required. The cost for maintaining and inspecting underground secondary services has been budgeted in account 5155.

4.7 Grounding

Lightning from storms 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 had incorporated tens of thousands of dollars put in to arrestor and grounding installations to protect Innisfil Hydro's assets. Older installations like overhead and pad mounted transformers installations, steel cross arm locations and separate dead end arrestor locations that have been existing for many years generally confirm that 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, $18,000 would be needed. This amount has not been budgeted in the 2013 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 $14,500 is required to verify operation maps in the field, which has not been budgeted for in 2013.

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. 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:

- Theft of copper
- Vegetation
- Fencing
- Litter
- Health & Safety
- Station Grounding (visual)
- Condition of SCADA building
- Transformer temperature
- Reclosure operations

There are ten privately owned 44 kV transformer stations connected to Innisfil Hydro's distribution system. Innsifil 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 cost for monthly inspections is budgeted in account 5016. Annual distribution station maintenance includes weed and vegetation control, grass cutting, snow plowing, supervisory control and data acquisition (SCADA) maintenance. The cost for annual maintenance is budgeted in accounts 5114, 5125 and 5012. Due to the evidence of copper theft from substation sites, security at substations has started to be implemented in 2012. Each station security system will have the following features and response protocol.

- Driveway sensor to activate flood light(s) inside the station upon vehicle entering driveway;
- Key activated arm and disarm switch at main entry;
- Magnetic contact on main entry gate;
- Motion sensor(s) inside gated compound (designed to minimize nuisance alarms) which will activate alarm and flood light(s);
- Alarm signals will be communicated via existing SCADA system to on call Manager;
- Securatas Guard Service will provide onsite alarm verification at request of on call Manager prior to Police dispatch;
- On site motion triggered camera will record activity within station.

The contingent cost of copper theft remediation greatly exceeds the scrap copper value that is being taken. Substation security will deter unauthorized entry and therefore improve public safety and system reliability.

5.2 Major Service

On a four year rotation, distribution stations are switched out of service and maintenance is 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 is budgeted in account 5114. 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	1996
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 seven 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. Five

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 Cru Solutions Inc., operated by ERTH Corporation (formerly Erie Thames Power Corporation) 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. Any meter reading problems are investigated immediately by Innisfil Hydro and or Cru Solutions for remedial service. The cost for maintaining wholesale meters is budgeted in account 5175.

6.1 Retail Meters

Innisfil Hydro has over 14,500 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 sample tested. If sample testing shows meter accuracy for residential meters, then sample groups can pass inspection without being re-sealed.

All retail smart meters are read on a daily basis by wireless technology. In 2012, there are approximately 4 residential meters that were not replaced with smart meters due to access restrictions. Staff are diligently working with customers to alleviate the restrictions.

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. The annual cost for maintaining retail meters is budgeted in account 5065.

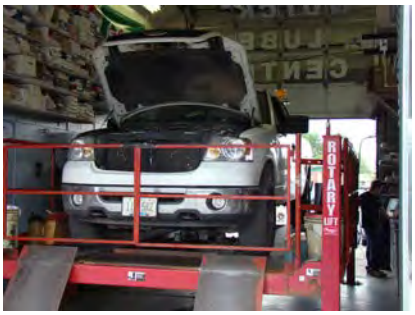
Contract negotiations were completed in 2009 with KTI/Sensus for supply of smart meters, with Olameter for mass deployment of the meters and with Kineiq/Savage Data Systems for Operation Data Storage of the flow of data from the smart meters. The Advanced Metering Infrastructure (AMI) installed is a tower based solution for communicating with deployed smart meters. Two existing towers were chosen, the Town of Innisfil's Churchill Tower and the Town's Big Bay Point Tower on Innisfil Hydro's substation site. Communications equipment was installed at both locations early in 2009, with communications established between the towers in early May. Mass deployment of smart meters commenced mid-September 2009, with substantial completion of March 2010. Innisfil Hydro is now registered with the provincial Meter

Data Management Repository (MDM/R) and have been assigned an identification number.

Time-of-use (TOU) billing to standard supply residential and low volume general service customers commenced on June 1, 2011.

7.0 Vehicle Maintenance

7.1 Service



Innisfil Hydro contracts out some line and all substation maintenance and construction. Innisfil Hydro does not have internal vehicle maintenance staff or equipment and out-sources that function. Innisfil Hydro has fourteen motorized vehicles in its fleet consisting of 1-double bucket line truck, 1-single bucket line truck, 1-RBD, 1-1 ton dump truck, 5 pick-up trucks, 5 Ford Escape Hybrids and 1 forklift. The vehicle replacement plan includes no replacement vehicles in 2012. Most of these vehicles do not meet the weight threshold for Commercial Vehicle Operator Registration (CVOR) except for the one ton dump truck and the three line vehicles. 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 cost for maintaining Innisfil Hydro's fleet is 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 analysis. Maintenance costs will be monitored to determine if they exceed the depreciation of a replacement vehicle. Surplus equipment is sold or disposed of for the greatest benefit to Innisfil Hydro.

YEAR	VEHICLE	TRUCK #	PLATE #
1993	GMC BUCKET TRUCK MODEL WG64	301	359 1YH
2000	GMC PICK-UP WITH DUMP BOX	94	1339XV
2004	CHEVY SILVERADO PICK-UP	84 (Student Truck)	1356NC
2005	DODGE RAM PICK-UP	87 (Julie Jeffels)	XP3 286
2005	DODGE RAM PICK-UP	91 (ON CALL TRUCK)	3765NS
2006	FORD F150	93 (Sheldon Lamoureux)	1185RZ
2008	FORD ESCAPE (HYBRID)	92 (Milan Boldin)	BDBA902
2008	FORD ESCAPE (HYBRID)	85 (Min Gill)	ACMR852
2009	FORD ESCAPE (HYBRID)	88 (Tony Mendicino)	AEME615
2009	FORD ESCAPE (HYBRID)	89 (Pete Stephens)	AEME616
2010	POSI PLUSSINGLE BUCKET MODEL FM2	302	185 9ZB
2010	FORD ESCAPE (HYBRID)	95 (Steve Edwards)	BJWA 824
2010	REEL TRAILER	402	H6112Y
2010	PORTABLE TRAFFIC SIGNALERS (2)	404 (For Both)	NO PLATES
2011	CHEVY SILVERADO HYBRID	96 (Wade Morris)	AA52433
2011	FORD SRW F350 PICK UP	101 (ROB REAL)	3809ZJ
2011	FLOAT TRAILER	403	H6607W
2011	POLE TRAILER	401	H6113Y
2011	FREIGHTLINER RBD	201	554 8ZR

8.0 Property Maintenance

8.1 Sites

Innisfil Hydro owns 10 substation sites and one 3.3 acre head off site. A new 3.5 acre head office site is being purchased in 2012 at the Town's Administrative Campus at 2147 Innisfil Beach Road along with a one acre parcel for a substation in Big Bay Point. 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.

The following list includes all properties owned by Innisfil Hydro and their respective land size and 1999 assessment values.

Innisfil Hydro Land Values

Distribution Stations			
Land Description	Address	Size Acreage	FMV 1999 ($)
Alcona Land	835 Innisfil Beach Rd	0.12	18,000
Brian Wilson DS	1434 Innisfil Beach Rd	2.00	112,000
Big Bay Point DS	709 13th Line	0.91	66,000
Cedar Point DS	733 6th Line	1.84	106,000
Cookstown Land	18 Victoria St.	0.08	17,700
Innisfil DS	2255 Hwy 89	0.28	36,500
Lefroy DS	1495 Kilarney Beach Rd	0.82	62,000
Leonard's Beach DS	2895 25th SR	0.28	35,500
Sandy Cove DS	1104 Lockhart Rd	0.91	66,000
Stroud DS	2135 Lockhart Rd	0.38	45,000
Barrie Land	22 Saunders Rd	3.5	(2012) 465,000
Yard	2033 Commerce Park Dr	1.3	88,000
Eng/Fin	2061 Commerce Park Dr	1.0	(2012) 500,000
CS/Warehouse	2073 Commerce Park Dr	1.0	(2012) 550,000

8.2 Buildings, Head Office

The head office site includes one wood frame building for Customer Service, one wood frame building for Engineering/finance, one wood framed building for the warehouse and two used public school portables (not shown). 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 cost for maintaining the head office is budgeted for in accounts 5085, 5340 and 5620.

The existing facility is not capable of facilitating growth needs. A long range staffing and space needs analysis was undertaken that was correlated with long-term growth projections. A professional architectural firm (McKnight Charron Laurin Inc. Architects) was hired to undertake a study which consisted of the following options:

1. Staying at the same location and making the necessary upgrades and additions to the existing five buildings.
2. Staying at the same location and construct a new building, replacing the five existing buildings.
3. Purchasing a neighbouring commercial property, upgrade and expand the existing buildings.
4. Purchase a green field commercial site and construct a new building.
5. Acquire the vacant Town of Innisfil old administration building and make the necessary upgrades and additions.

The recommendation was for option 5 which provided the best overall value. The site was the only one that was fully serviced from among the five options. It was closer to the centre of Town for response purposes, land was less expensive than the existing site and there is access to public transportation. Architectural renderings were undertaken for the new site with the construction of a single building to engender efficiencies as compared to the existing five buildings. Due to the high cost of renovating the existing building (bricks, roof, HVAC, windows, washrooms, elevator, asbestos, accessibility, etc.), it was deemed prudent to demolish the existing built and construct a new one to LEED standards. It is anticipated that substantial completion of this new building will occur in December 2013.

The building design incorporated some extra space for anticipated future growth needs. This space is designed in a way that it could be leased out to a commercial party until required. The Town of Innisfil's Economic Development Department has indicated that there is a shortage of commercial office space available and that a positive rate of return could be achieved.

Of the three existing lots that Innisfil Hydro currently uses for their head office, two lots are anticipated to be sold to the Town of Innisfil at appraised value for a water reservoir and pumping station. The third lot is used for outdoor storage and will remain as an outdoor storage yard because it contains a transformer station and was designed for a second transformer station on site.

9.0 Equipment Maintenance

9.1 Office Equipment

Office equipment includes desks, chairs, filing cabinets, office partitions etc. Repairs to office furniture occurs as needed and replacements occur generally after 10 years plus. 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 cost of office equipment is budgeted in account 1915. 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, wireless equipment etc. 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 cost of computer hardware is budgeted in account 1920. Surplus equipment is sold or disposed of for the greatest benefit to Innisfil Hydro.

9.3 Line Tools

Innisfil Hydro incorporated in-house Line Staff and Line Tools in 2010 so Line equipment is generally in new condition. Innisfil Hydro also purchases and operates line equipment such as underground cable locating equipment, fault locating equipment, meter analyzers and AVO meters, etc. The equipment is generally kept until it's no longer working or cost beneficial to maintain or replaced with new technologies. The cost of tools is budgeted in accounts 1935, 1940 and 1945.

10.0 Innisfil Beach Road Urbanization

The Town of Innisfil is 'urbanizing' 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 project was initially a four year project with utility relocates starting in 2009. The project has been changed to a two year project with Utility relocates completing in 2011.

The Town of Innisfil has finalized the urbanization design through a By-law. The same By-law requiring utility relocates to be underground. Innisfil Hydro was provided notice 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 the 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 (which is the total project cost without including contributions from the Town of Innisfil) for the relocation of distribution assets on Innisfil Beach Road as follows:

2009 - $1,000,000

2010 - $3,900,000

2011 - $ 464,800

2012 - $ 50,000

11.0 Long Range Load Projections

Long range load projections have been plotted from years 2011 to 2031. The parameters for the load growth model utilizes all known growth plans whereby Innisfil Hydro's customer base will grow to over 35,000 by 2031. Future demand has been estimated at 2 kW / resident which will include loads for commercial requirements such as schools, stores and businesses.

Innisfil Hydro currently has a supply limit of 63 MW from Hydro One and is projected to grow to 124 MW in 2031. This current supply limit will be exceeded so Innisfil Hydro has acquired one new 44kV feeder from Hydro One in late 2009 and another new 44kV feeder is planned for 2017. These new feeders will be able to supply Innisfil until 2020. At that time, four more 44kV feeders or a new Transmission Station will be required until

anticipated build-out in 2031. Innisfil Hydro Staff have met with Hydro One in 2010 to share their long range planning requirements. A report was issued by Hydro One and it is available in Appendix 6. It is expected that dialogue will resume between Innisfil Hydro, Powerstream and Hydro One again in 2014 or 2015 to continue long range supply planning.

Two New 44 kV Feeders into Innisfil Hydro

In the early part of the 2000s, 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 three feeder locations (9M2, 9M3 & 9M6), two of 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 (9M4 & 9M1) are on the same pole line, from 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 other supply feeders from Alliston TS available would have limited that interruption to about 10 minutes. There was no contribution to Hydro One required for one new 44kV feeder. The estimated contribution required to Hydro One in 2008 for the second feeder was $930k and was not undertaken. The project for a single circuit was completed in late 2009.

An approximate four (4) km of single circuit 44 kV sub-transmission was built from the 10 Sideroad of Essa south on Highway 27 and across the 5th Line of Innisfil to the 5 Sideroad. The one new incoming feeder should provide enough capacity for Innisfil until 2017, at that time, the second circuit will be required. Approximately sixty-five (65) poles replaced existing smaller single phase and three phase poles in order to accommodate for the sub-transmission circuits. Within the scope of this project, one metering unit and three (3) 44 kV SCADA load break switches were installed; two (2) switches at the Innisfil Hydro/Hydro One border and a third as a paralleling point within Innisfil Hydro’s system.

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

APPENDIX C - MINIMUM INSPECTION REQUIREMENTS

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

APPENDIX C - MINIMUM INSPECTION REQUIREMENTS

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.

APPENDIX C - MINIMUM INSPECTION REQUIREMENTS

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

8

APPENDIX C - MINIMUM INSPECTION REQUIREMENTS

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						

Notes to Table C-2:

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.

APPENDIX C - MINIMUM INSPECTION REQUIREMENTS

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							

APPENDIX C - MINIMUM INSPECTION REQUIREMENTS

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.

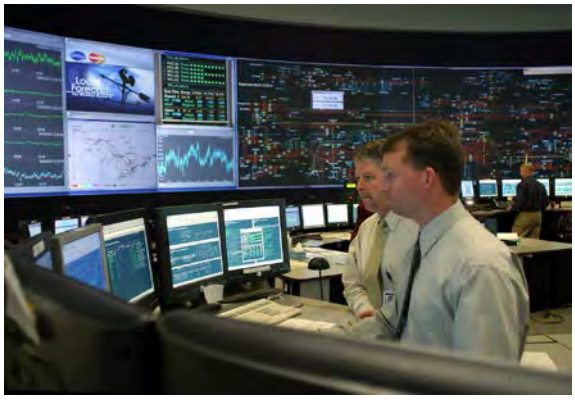
3. Distributors are required to retain this information and make it available to the Board upon request.

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.

Appendix 4

WINSFIL HYDRO DISTRIBUTION SYSTEMS LIMITED



Reliability Management Plan

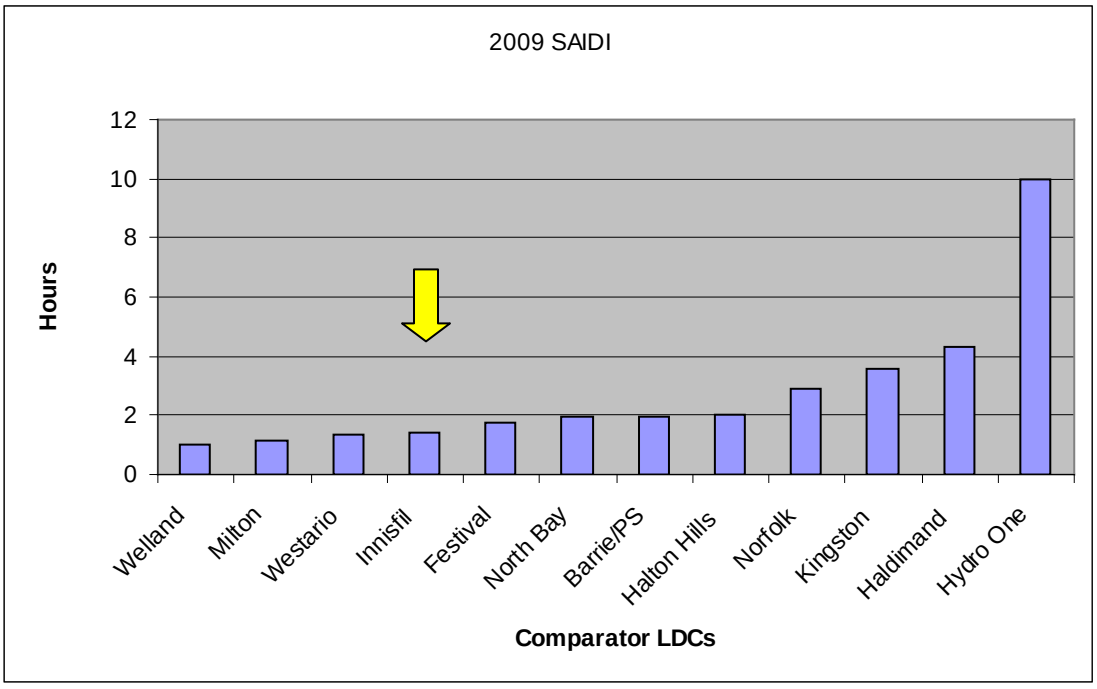
2012

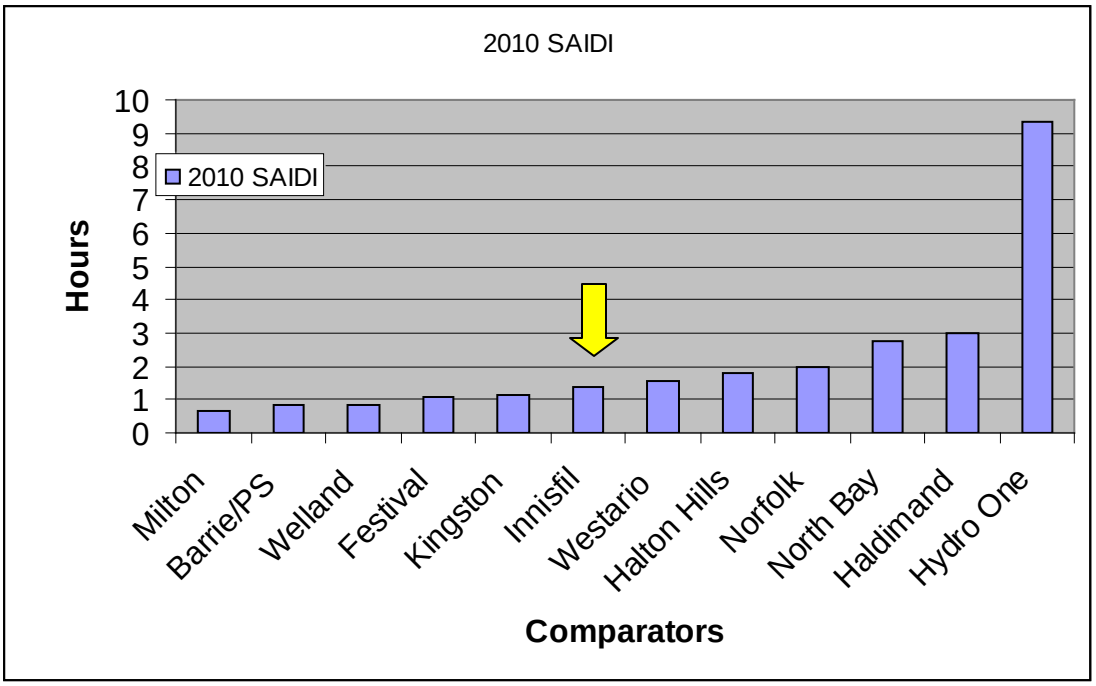
The Distribution System Code (DSC) requires an LDC to maintain its distribution system in good working condition, as follows:

"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."

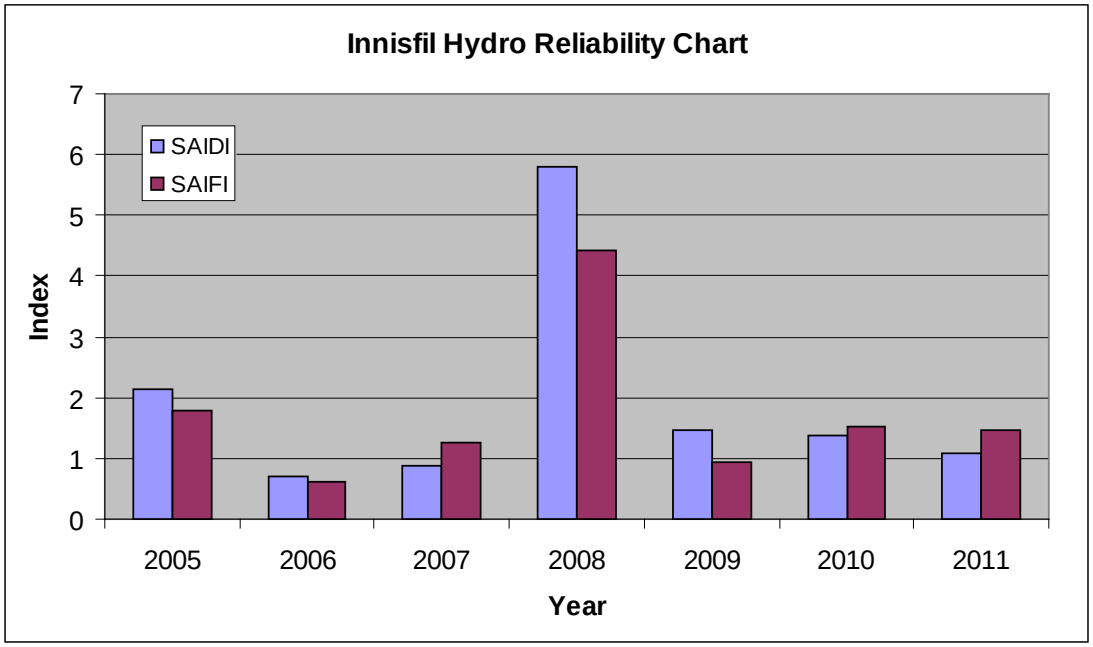
Together with the Asset Management Plan in the Business Plan, the Reliability Management Plan utilizes statistical evaluation tools to evaluate system reliability by diving into the root causes of electrical interruptions and incorporating operational and capital plans to provide the best overall cost benefit for system reliability.

By comparing Innisfil Hydro's reliability against their comparator group (2009 SAIDA vs. 2010 SAIDI), it is evident that Innisfil Hydro has moved from 4th place in 2009 to 6th place in 2010 of system average interruption duration statistics. The root cause of the slippage within the comparator group is not known even though Innisfil Hydro has improved over the period. 2011 statistics will not be available until late 2012.





From the graph below, there has been a marginal SAIDI improvement over the past three years. The 2008 anomaly was caused by loss of supply at Hydro One which involved the failure of two transformers at Alliston TS.



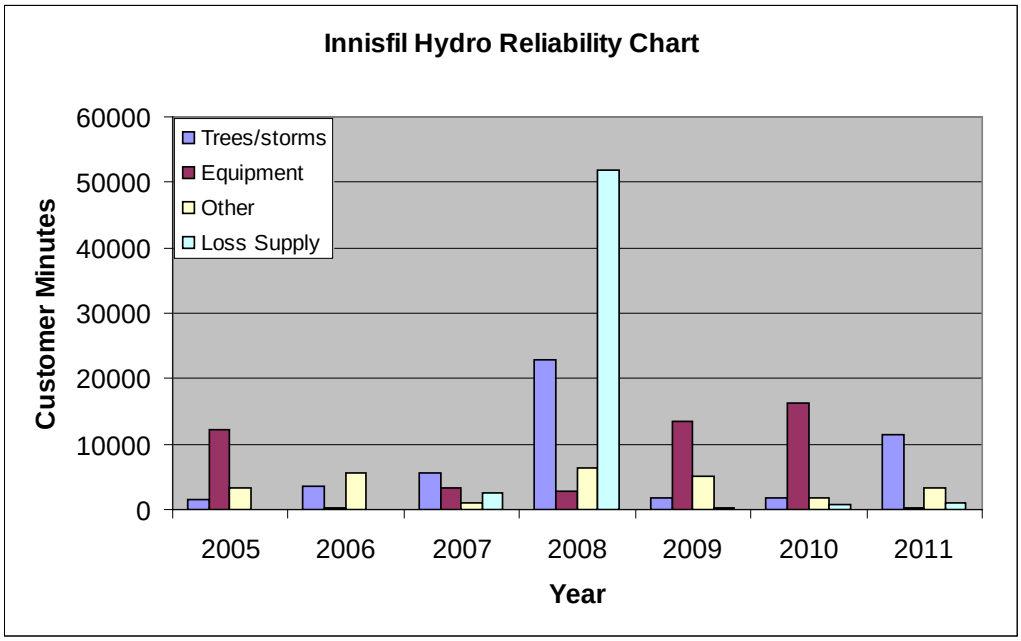
Diving into interruption statistics more deeply, an analysis has been developed with regard to the underlying causes of the interruptions in service. These underlying causes have been broken down into four categories initially as follows:

1. Adverse weather and tree contacts
2. Defective equipment
3. Other – unknown causes, foreign interference and scheduled outages
4. Loss of supply.

As seen from the Innisfil Hydro Reliability Chart below, the largest interruption duration cause in 2009 was equipment failure. The loss of supply from Hydro One in 2008 has virtually disappeared. This success was primarily due to the replacement of two transformers at Alliston TS by Hydro One and the completion of one new 44kV circuit into Innisfil in late 2009. The impact of tree contact and storm related interruptions have stayed the same from 2009 to 2010.

Weather mitigation has been accomplished by shortening the tree trimming rotation from a four year cycle to a three year cycle. With this schedule, one third of the trees in Innisfil Hydro's distribution territory that have proximity to power lines will be trimmed. Trees are trimmed by an independent contractor which was chosen through a public tender process.

Statistics in the OEB Yearbook for 2010 now includes additional reliability information which has loss of supply removed. Having pure distribution system reliability would be more helpful when analyzing comparator LDCs. Since 2010 is the first year this information is available, the 2012 plan will include reliability data exclusive of loss of supply to compare 2010 and 2011 reliability years.



The Innisfil Hydro Reliability Chart measures actual customer interruption minutes by category. The largest cause for interruptions in 2010 is equipment related failures, which is a marginal increase over the previous year.

In 2011, equipment failures virtually disappeared and storm related interruptions prevailed. From the storm related interruptions, 85% was caused by a single event on February 19, 2011 from feeder 13M3 out of Barrie supplying the north part of Innisfil. The tree trimming cycle for 2011 focused on the 13M3 service area and should have addressed this reliability factor for 2012.

The 13M3 service area has the highest concentration of trees amongst all of the tree trimming cycles. There is justification to warrant a further review of the frequency and efficacy of tree trimming in that area.

Appendix 5

Innisfil Hydro

Health and Safety Business Plan

Goal

The Joint Health & Safety Committee (JHSC) is compiled of employer and employee representatives who work together to pro-actively improve health and safety in the workplace.

Member Duties

1) Identify sources of danger or hazards.
2) Assist in writing recommendations for improvements to the employer.
3) Obtain certain information from the employer regarding actual or potential hazards.
4) Be consulted about testing methods and strategies.
5) Be present at the beginning of testing, if the member feels their presence is required.
6) Inspect the workplace at least once per month or at least a section of the workplace once a month.
7) Inform the JHSC of actual or potential hazards.
8) Assist in resolving matters when a worker refuses work on the grounds that it endangers health and safety.
9) Review the Health & Safety Policy on an annual basis, revise as necessary.

The H&S Committee Members will make recommendation for funds required to the budget committee for the annual budget. Items that require funding includes, but is not limited to:

- Attendance to E&USA conferences, workshops & annual general meetings.
- Attendance to IAPA or other pertinent safety associations for events.
- General or specialized training required for H&S Committee Members
- Recommendation for funding to facilitate recommended safety training for staff.
- Funds required to facilitate statutory obligations, meetings and staff participation.

Action Plan

This health and safety business plan is the overall strategy for planning and implementation of a health and safety system including the following action plan items:

- Long and short-term health and safety targets and objectives is ZeroQuest. Innisfil Hydro has won E&USA's President Award for 250,000 no lost time hours in 2005. Another 250,000 hour mile stone was reached in year 2011 and a 500,000 hour accident free celebration is planned for in 2012.
- Project assignment responsibilities are determined at every H&S committee meeting. Target dates for completion are provided and tracked on the minutes of every regular scheduled meeting.
- Anticipated funding requirements for H&S Committee resources shall be provided to the budget committee by mid September of each year. The average amount budgeted per year for the Health and Safety committee is $5,000. All other staff training costs are budgeted within departmental human resource training budgets.
- Securing the Silver Effort Level has been completed in late 2009.
- Securing the Gold Outcomes Level is expected to be completed in 2013.
- The Action Plan will be reviewed on an annual basis by the H&S committee to track past performance and to set new targets for subsequent years.

SOUTH SIMCOE AREA STUDY

ADEQUACY OF TRANSMISSION FACILITIES

AND

TRANSMISSION PLAN 2011 - 2025

January 12, 2011

Prepared by Hydro One in Consultation with the OPA

Prepared by: Alessia Dawes & Sacha Constantinescu

Approved by: John Sabiston

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EXECUTIVE SUMMARY

A transmission reinforcement plan is recommended for the South Simcoe area to address area reliability and capacity needs.

The Simcoe area is under intense development pressures and its population is expected to increase significantly by 2031. The South Simcoe area, which covers Barrie, Alliston, Innisfil and Bradford, is summer peaking, and had a non-coincident combined peak demand of about 420 MW in 2007. The demand dropped in 2008 (about 400 MW), increased in 2009 (about 430 MW), and reached 444 MW in 2010. It appears that the demand in the South Simcoe area was not greatly affected by the cooler summers and the economic downturn.

This assessment, which was carried out in consultation with the Ontario Power Authority has identified the following needs in the area over the next fifteen years:

- Inadequate 44 kV voltage levels at Midhurst TS and Orillia TS in the near term.
- Inadequate supply capacity to meet growing load requirements for Alliston TS in the medium term (5-10 years).
- Longer-term needs (>10 years out), include:
    - Inadequate transformation capacity to meet growing load requirement for Essa TS 500/230 kV auto-transformer.
    - Inadequate supply capacity to meet growing load requirements, as well as End-of-Life (EOL) issues expected in 2020 for Barrie TS.
    - Inadequate transmission capacity to meet the combined load requirements of the transformer stations served by M6E/M7E.
    - Marginally adequate supply capacity at Everett TS due to current transformer (CT) ratios.
    - Marginally adequate transmission capacity along E3B/E4B to meet load requirements for Barrie TS.

A multi-stage action plan to meet the above needs has been identified. The installation of two low-voltage capacitor banks at Midhurst TS and Orillia TS to restore the voltage to adequate levels was identified for immediate action. In the medium term, an upgrade of Alliston TS to increase its capability of meeting future load requirements will be considered by Innisfil Hydro. Options to meet longer-term needs were identified through this study but decisions were deferred until the next study update in 2014 (or earlier if required, as the situation will be monitored). These options include:

- installing a third 500/230 kV transformer at Essa TS to increase its transformation capacity
- changing ratios of the metering CTs at Everett TS to increase its supply capability
- installing in-line breakers on M6E and M7E to allow for increased load requirements and help meet IESO's load restoration criteria
- replacing End of Life (EOL) equipment at Barrie TS, as well as at other stations that have equipment at EOL.

INTRODUCTION

This adequacy assessment of the South Simcoe area focused on the electrical supply to four load stations—Midhurst TS, Barrie TS, Everett TS, and Alliston TS—as well as Essa TS, the primary supply point for the area, and the 230 kV and 115 kV transmission lines connecting them.

Geographically, the South Simcoe area consists of nine townships and/or municipalities - Adjala-Tosorontio, Barrie, Bradford West Gwillimbury, Essa, Innisfil, New Tecumseth, and parts of Oro-Medonte and Springwater. Electricity distribution in the South Simcoe area is carried out by Innisfil Hydro Distribution Systems Limited, PowerStream Inc. and Hydro One. A map of the area is shown in Appendix A, Figure 1.

The South Simcoe area is summer peaking, and had a non-coincident combined peak demand of about 420 MW in 2007. The demand had dropped in 2008 (about 400 MW), increased in 2009 (about 430 MW), and was at its highest in 2010 (about 444 MW). It appears that the demand in the South Simcoe area was not greatly affected by the cooler summers and the economic downturn. A plausible reason for this is articulated in the provincial report called *Simcoe Area: A Strategic Vision for Growth*, dated June 2009, found on the following website:

https://www.placestogrow.ca/images/pdfs/Simcoe_ENG.pdf

The Simcoe area – comprised of Simcoe County and the Cities of Barrie and Orillia – is unique in that it is under intense development pressures and also contains extremely important environmental assets for the Greater Golden Horseshoe. In 2006, the Province released the *Growth Plan for the Greater Golden Horseshoe* (the Growth Plan) which was updated in 2010, and can be found at the following link:
https://www.placestogrow.ca/index.php?option=com_content&task=view&id=210&Itemid=15
This plan is aimed at boosting job creation and improving quality of life while curbing urban sprawl and protecting the natural environment and farmland. Much of this growth will be focused in Barrie and Innisfil, with a lot of new housing being built, and the creation of high quality manufacturing and industrial jobs.

In August 2009, a study was initiated by Hydro One as a result of Local Distribution Companies (LDCs) in South Simcoe inquiring about transformation capacity and transmission adequacy.

The purpose of the study was to assess the load growth in the South Simcoe area and ensure that adequate transmission and connection facilities will be available to meet the electrical demand requirements over the next decade. LDCs that provided load forecasts included:

- ★ Hydro One Networks Inc. – Distribution
- ★ Innisfil Hydro Distribution Systems Limited
- ★ PowerStream Inc.

1. EXISTING ELECTRICAL FACILITIES

1.1 Transmission in Simcoe County

Electrical supply in this area is provided through 500 kV, 230 kV and 115 kV transmission lines and step down transformation facilities (transmission stations, TS) as shown in Appendix A, Figures 2 and 3.

The hub of the electrical system for Simcoe County is Essa TS. Essa TS provides the only connection to the 500 kV system in this area, which supplies the majority of resources with electricity to meet demand in Simcoe County. The Simcoe County transmission system is connected to Essa TS as follows (refer to Appendix A, Figures 2 and 3):

1. Two 230 kV radial circuits (E26/E27) emanating north to supply Waubaushene TS and Parry Sound TS;
2. Two 230 kV circuits (E8V/E9V) first heading south to Orangeville TS, and then going west providing a connection to Bruce A Generation Station (GS) via 230 kV circuits B4V and B5V;
3. Two 230 kV circuits (M6E/M7E) heading northeast to Midhurst TS and making a network connection at Minden TS;
4. Two 230 kV circuits (E20S/E21S) heading west to Stayner TS, and then transforming into a single 115 kV circuit (S2S) making a network connection to Owen Sounds TS (and ultimately Bruce A Generating Station); and,
5. Two 115 kV circuits (E3B/E4B) into Barrie TS

Voltage support is provided in the area by two high voltage capacitor banks at Essa TS.

All stations in Simcoe County were considered in the analysis to determine the adequacy of the existing transmission system however only the following stations in the South Simcoe study area were considered for transformation capacity issues: Allistion TS, Barrie TS, Everett TS and Midhurst TS.

1.2 Contracted Generation

New generation contracted under the Ontario Power Authority's Renewable Energy Standard Offer Program (RESOP) and Feed-in Tariff (FIT) program, are shown in Appendix B, Tables 1A and 1B, respectively. These show that the two programs would add about 10 effective MW of renewable generation in the South Simcoe area by the end of year 2012.

2. ADEQUACY OF EXISTING FACILITIES IN SOUTH SIMCOE

2.1 Study Assumptions

The assessment of supply adequacy and security in the South Simcoe area was carried out for the 15 year period 2011 to 2025 using the forecast peak demand for the area. The assumption and the criteria used are as per the IESO Ontario Resource and Transmission Assessment Criteria:

http://www.theimo.com/imoweb/pubs/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

2.2 Load Forecast

The load forecast, prepared in late-2009 and revised in 2010, used in this assessment is shown in Appendix C, Table 2a and 2b. The peak total summer load in Simcoe County is projected to grow by an annual rate of about 2.2% before conservation and distributed generation (DG) and 1.1% when these local resources are taken into account. Loads in the South Simcoe area (supplied by Alliston TS, Barrie TS, Everett TS and Midhurst TS) are projected to increase by an annual rate of 3.1% before conservation and DG and 1.9% with conservation and DG.

The projected rates of increase are consistent with the information provided in the Simcoe Area report, referred to above. The report states that growth will be directed to the five largest urban nodes, three of which are located in the South Simcoe area: Barrie, Alliston and Bradford. This growth allocation results in a significantly higher load growth rate for the South Simcoe area compared to the rest of the Simcoe area, with a growth rate of 1.3%

2.3 Supply Capacity and Needs

Single and double element contingencies were considered in assessing the adequacy and reliability of the South Simcoe area. The single element contingencies, or [N-1] contingency events, are helpful in determining the maximum load that can be supplied to an area or part of the area following the critical contingency while meeting all requirements for stability, equipment rating, and voltage. This maximum load for a transmission line or circuit is the load meeting capability (LMC) of the supply lines to the area or part of the area. The maximum load for a transmission station is the 10-day Limited Time Rating (LTR) of one of the two power transformers that make up that station (normally the most limiting transformer is considered).

2.3.1 Supply Capacity to Alliston TS, Barrie TS, Everett TS and Midhurst TS

Before consideration for conservation, Alliston TS is expected to be loaded beyond its 10-day LTR supply capacity in year 2017 according to Appendix C, Table 2a. After conservation, Alliston TS is expected to be loaded beyond its 10-day LTR supply capacity in year 2019. This increase in load is mainly due to growth projected in the Innisfil Hydro service territory.

Everertt TS load is expected to stay within the station "unlimited" 10-day LTR for the entire study period according to Appendix C, Table 2a. Currently Everett TS has a "limited" 10-day LTR due to the tap ratio setting of low voltage metering CT's (current transformers). Once the minimum load of the station is greater than 8 MVA, the tap ratio's can be increased and the "unlimited" 10-day LTR applied.

Barrie TS is not expected to be loaded beyond its 10-day LTR within the study period according to Appendix C, Table 2a. GO Transit's proposed new substation load of 20 MW, which may be operational sometime around 2020, was not considered in the forecast. GO Transit is considering electrifying its train system, thus removing all diesel locomotives and replacing them with electric ones. An option under consideration is to have Barrie TS feed the GO Transit substation. Note that Hydro One has declared Barrie TS to be End-of-Life (EOL) by year 2020. By year 2020, the majority of the high value components at Barrie TS are projected to trend towards EOL. Significant re-investment may be required in order to sustain and improve functionality and reliability levels. As well, the existing old low voltage structure poses limitations for uprating and replacing assets, and also poses challenges during maintenance and construction work, as the personnel must work close to live equipment. These issues at Barrie TS will require further study and discussion in order to determine the best solution.

Midhurst TS load is expected to stay within the station 10-day LTR for the entire study period according to Appendix C, Table 2a.

2.3.2 Supply Capacity of the 500 kV Network

The majority of electricity supply in Simcoe County is provided via two 500/230 kV auto-transformers located at Essa TS named T3 and T4. The 500 kV and 230 kV systems are connected via these two 750 MVA auto-transformers at Essa TS. Due to the load growth in the area, T3 auto-transformer would be nearing its 10-day LTR by 2020 before conservation and DG, however, once conservation/DG are taken into account, T3 would remain below its 10-day LTR throughout the whole study period. T4 auto-transformer nears its 10-day LTR as early as 2024.

The study assumed the second 230 kV shunt capacitor bank will be installed at Essa TS by November 2011. The installation of this capacitor bank is a need that was determined, and put into action by the North/South Reinforcement Project.

2.3.3 Supply Capacity of the 230 kV Network

Two double circuit 230 kV lines emanate out of Essa TS to supply power to step-down transformation stations in the South Simcoe area:

- ★ Alliston TS and Everett TS are supplied via a double circuit line (E8V and E9V) running southwest towards Orangeville TS; and,
- ★ Midhurst TS and several other transfor mer stations outside of the study area, are supplied via double circuit line (M6E and M7E) running northeast towards Minden TS.

The load meeting capability (LMC) of E8V/E9V circuits, due to thermal limitations on one circuit following the loss of its companion, is 444 MVA for the loss of E8V and 424MVA for the loss of E9V (due to thermal limitations on a section of E8V between Orangeville TS and Everett TS). At the end of the study period, year 2025, the combined load of Alliston TS, Everertt TS and Alliston TS Industrial customer is expected to be 341 MVA. Simulation of N-1 contingencies were required to be performed in order to determine that there are no foreseen circuit overloads for the duration of the study period for the loss of either E8V or E9V.

Circuits M6E/M7E also require simulation of N-1 contingencies in order to determine circuit overloads. Note that these circuits are comprised of many sections, each section with its own LMC due to various sag limitations. The Essa TS by Midhurst TS sections reach their LMC starting in year 2017 based on the load forecast without conservation and DG. The Cooper Falls Junction by Minden TS section of M6E reaches its LMC starting year 2024 and the Midhurst TS by Orillia TS sections reach their LMC starting year 2025.

The 230/115 kV auto-transformers, T1 and T2, at Essa TS currently supply load to Barrie TS only. Auto-transformer T1 is the most limiting of the pair and loading of T1 will remain within its 10-day LTR throughout the study period in the event that the companion auto-transformer, T2, is removed from service. However, if the required transformation capacity at Barrie TS were increased or additional load is needed to be supplied via the 115 kV system, both existing 230/115 kV autotransformers at Essa TS would need to be upgraded. In addition, the condition of T1 is poor and its End-Of-Life (EOL) is projected to be in 10-15 years (2020-2025).

2.3.4 Supply Capacity of the 115 kV Network

One 115 kV corridor supplies power to one step-down transformation station in the South Simcoe Area (as well as Simcoe County as a whole):

- Two single circuit 115 kV lines from Essa TS to Barrie TS (E3B and E4B).

The two 115 kV lines between Essa TS and Barrie TS (E3B and E4B) are also nearing capacity as the load at Barrie TS increases. This is particularly apparent on one 0.5 km section of circuit E3B near Essa TS, due to operating temperature limitations. These lines will be sufficient to supply Barrie TS in its existing state, however, if station capacity is increased at Barrie TS, and/or a new connection is made to circuits E3B and E4B, these circuits will require upgrading.

2.3.5 Load Security and Restoration

The load restoration criteria requires that following design criteria contingencies, all load lost must be restored within 8 hours, load loss in excess of 250 MW must be restored within 30 minutes, and load loss amount between 150 and 250 MW within 4 hours.

In addition to this, load security criteria require that not more than 600 MW of load may be interrupted by configuration. The 600 MW load interruption limit reflects the established practice of incorporating up to three typical modern transmission stations on a double-circuit line. A typical TS is a 75/125 MVA DESN station with transformer overload capability factor of 1.6 in the winter and 1.5 during summertime.

There are three pairs of 230 kV double circuits in the south Simcoe area: E8V/E9V, M6E/M7E, and E26/E27.

E8V/E9V
By the end of the study period the total load connected to E8V/E9V is 296 MW, not considering conservation and DG. Since the two circuits share a common tower line a valid [N-2] contingency event is the loss of a tower resulting in the loss of both E8V and E9V circuits. Simulations were performed and the total 296 MW of load can be restored from either end of the circuits, Essa TS or Orangeville TS. Therefore, depending on the severity of the transmission line failure, total load restoration is achievable within 8 hours.

M6E/M7E
The total load serviced by circuits M6E/M7E is winter peaking. By winter 2020/2021, the total load connected to M6E/M7E is 610 MW before accounting for conservation and DGs, however the load will remain below the 600 MW threshold throughout the study period once these factors are included. Tables 3a and 3b contain the summer and winter load forecasts, respectively, for all stations supplied off of M6E/M7E. Since the two circuits share a common tower line, a valid [N-2] contingency event is the loss of a tower resulting in the loss of both M6E and M7E circuits. Simulations were performed and the total 610 MW of load cannot be restored from the Minden TS end, since the station can only supply about 300MW to these circuits. Depending on the sequence of stations being restored there could be at least 300 MW of unsecured load. The amount of restored MW of load is greater from the Essa TS, however, it is limited by the LMC of the Essa TS by

Midhurst TS section, which would allow for approximately 400 MW to be supplied. Up to 22 MW of load could be restored through low voltage feeder transfers, which would take about one hour to complete following the contingency.

Therefore load security criteria will not be exceeded within the study period when conservation and DGs are taken into account. With respect to load restoration, depending on the severity of the transmission line failure, up to 420 MW of load is restorable until one of the outage circuits is restored, at which point the remaining load can be supplied. With the current arrangement, a severe enough failure can prevent this section of line from meeting IESO's load restoration criteria.

E26/E27
The total load serviced by radial circuits E26/E27 will not exceed 160 MW by the end of this study period and a contingency would only affect Parry Sounds TS and Waubashene TS. To restore full operation to these transformer stations, E26/E27 would have to be placed back into service.

2.3.6 Needs Summary

In summary, the following needs are identified for the South Simcoe area:

Station Overloads
(a) Alliston TS is expected to reach the station 10-day LTR by summer 2017
(b) Essa TS 500/230 kV auto-transformer T3 is expected to reach its 10-day LTR by summer 2020
(c) Essa TS 500/230 kV auto-transformer T4 is expected to reach its 10-day LTR by summer 2024
(d) Everett TS is expected to reach the station's "limited" 10-day LTR by summer 2020

Voltage Deficiencies
(e) Midhurst TS DESN #1 is expected to experience post-contingency voltage deficiencies by summer 2011
(f) Alliston TS is expected to experience post-contingency voltage deficiencies by summer 2020.
(g) Midhurst TS DESN #2 is expected to experience post-contingency voltage deficiencies by summer 2021

Circuit Overloads
(h) 230 kV Transmission Line M6/7E, section Essa TS x Midhurst TS is expected to be over its LMC starting summer 2017
(i) 230 kV Transmission Circuit M6E, section Cooper Falls Jct. x Minden TS is expected to be over its LMC starting summer 2024
(j) 230 kV Transmission Line M6/7E, section Midhurst TS x Orillia TS is expected to be over its LMC starting summer 2025.

Load Security/Restoration Violations

(k) By winter 2020/2021, more than 600 MW of winter loading is expected to be connected to 230 kV transmission line M6/7E and could be lost due to configuration.

Equipment End-Of-Life based on Condition Assessments

(l) Barrie TS reaches EOL by year 2020

(m) Essa TS 230/115 kV autotransformer, T1, reaches EOL in 10-15 years.

Figure 4, on the following page, presents the needs for the South Simcoe Area, and the years in which they arise.

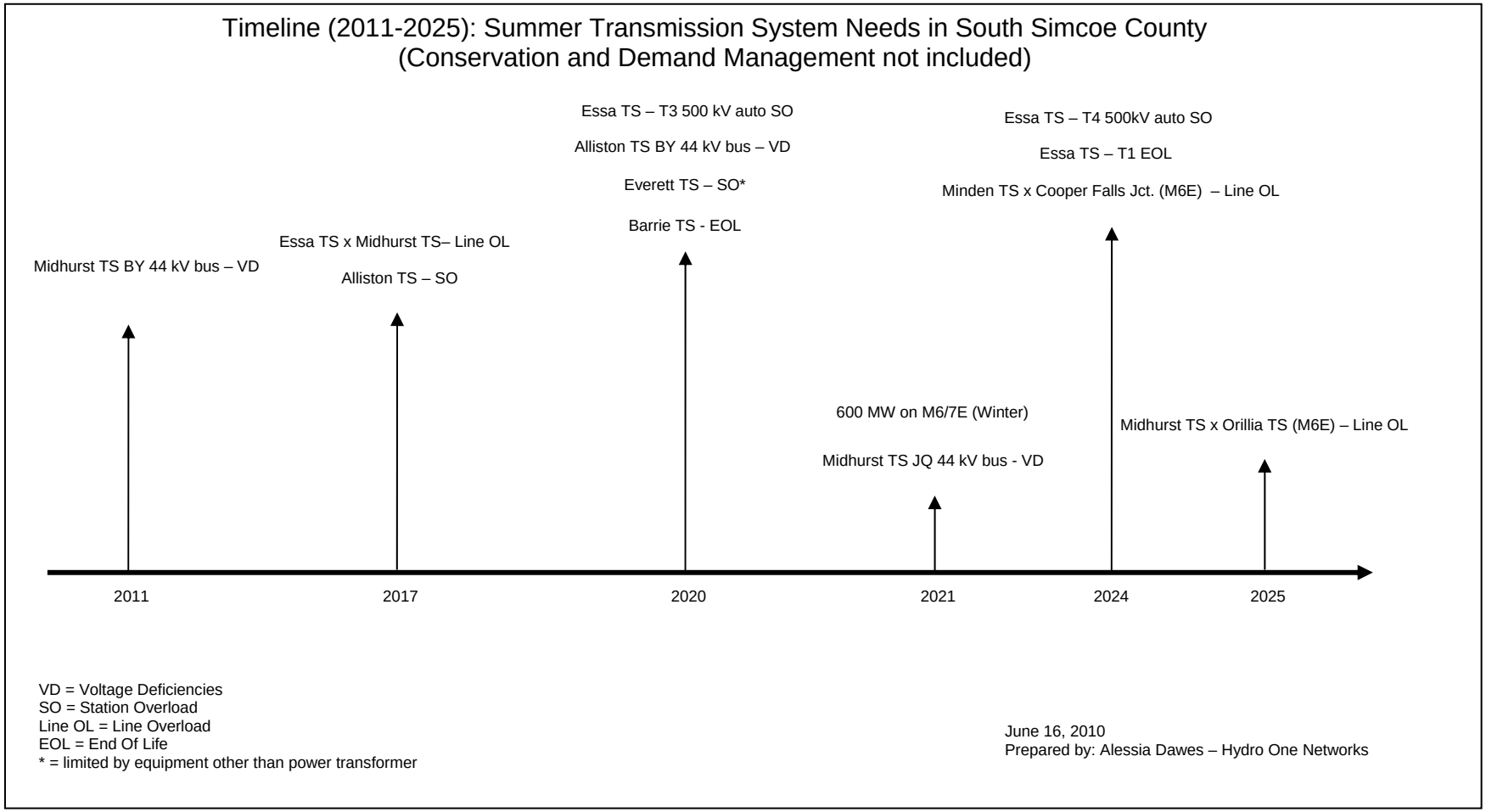


Figure 4: Needs for the South Simcoe Area

3. OPTIONS TO ADDRESS NEEDS

The following four sets of options were developed to address the needs identified above.

Note: All Prices are based on historical data (provided to Hydro One's Transmission Planner from Hydro One's Engineering and Construction Services under AR#19427 on March 26, 2010):

- ★ Taxes extra, overhead extra, interest extra
- ★ No escalation considered
- ★ No assumptions are made as to feasibility or construction
- ★ No assumptions made as to space requirements
- ★ No breakdown of price provided
- ★ Real Estate and Environmental costs extra

3.1 Options to Relieve Station Overloads

Table 1 outlines options that could relieve Alliston TS station overload by year 2017 (Near-term Supply Needs). Since Innisfil Hydro's load is expected to increase beyond the study period, a list of Long-term Supply Need Options are also provided in Table 1.

Table 2 outlines two options that could relieve Essa TS 500/230 kV autotransformer overloads.

Power flow through Everett TS is currently limited by the low voltage metering current transformers (CTs). The ratio setting of these CTs limits the station's 10-day LTR to 95.6 MVA however the power transformers are capable of 117 MVA. Due to low night time loading, the CT ratio cannot be changed at this time. Once more load is placed onto Everett TS resulting in higher night time loading, > 8 MVA, the ratio setting can be increased resulting in an increase to the 10-day LTR.

3.2 Options to Relieve Voltage Deficiencies

Table 3 outlines the option to relieve the voltage deficiency at Midhurst TS as well as voltage deficiency at other stations along M6E/M7E transmission line.

3.3 Options to Relieve Circuit Overloads

Table 4 outlines options that could relieve the circuit overloads along sections of M6E/M7E.

3.4 Options to Relieve Load Security/ Restoration Violations

Table 4, options 3, 4, and 5 could relieve load security and restoration violations for stations off M6E/M7E.

Table 1: Short Listed Options for the Relief of Alliston TS Station Overload – Assumed I/S date 2017 **(Near-Term)**

Option	Description	Adverse Effects	Alliston TS LV – VD	Historical Cost (costs include an additional estimated 30% for tax, overhead & interest)
Near-Term Supply Needs (Transformation Capacity within Study Period)				
1) Upgrade Alliston TS	★ From 50/83 MVA DESN to 75/125 MVA DESN ★ 230/44 kV or 230/44/27.6 kV ★ Likely have to upgrade 44 kV buswork & add feeder positions	★ No thermal violations ★ Alliston TS 44 kV bus voltage deficiences starting summer 2021	★ No material improvement to low voltage performance ★ LV capacitors would still be required	$ 28M Customers to pay for (at a minimum) additional transformation capacity and feeder positions
2) Upgrade Barrie TS	★ From 115/44 kV 50/83 MVA DESN to 230/44 kV 75/125 MVA DESN (or 230/44/27.6 kV) ★ Rebuild E3/4B to 230 kV Tx Line ★ Provide new LV structure and feeder positions	★ No thermal violations ★ No voltage violations	★ No need for LV capacitor banks within study period provided Alliston TS 10-day LTR is respected.	$62M (Line ~50%, Station ~50%) Customers to pay for (at a minimum) additional transformation capacity and feeder positions. Details on cost allocation for line upgrade uncertain at this time (consideration should be made for the decommissioning of Essa TS 115 kV yard).
Long-Term Supply Needs (by ~2031)				
3) Build Innisfil TS at 230 kV from Essa TS	★ Build new 14-15 km 230 kV Tx line from Essa TS into Innisfil ★ Build new 230/27.6 kV 50/83 MVA	★ No thermal violations ★ No voltage violations	★ No need for LV capacitor banks within study period provided	$140 M (Line ~35%, Station ~30%, Essa ~ 35%) Customer to pay for (at a minimum) the entire new

	station ★ Likely induce creation of Essa TS North yard, 230 kV switching ★ 3 feeders – 2024 ★ 5 feeders – 2031		Alliston TS 10-day LTR is respected.	Transformer station and the dedicated new transmission line. Details on cost allocation for the creation of Essa TS North yard is uncertain at this time. Subject to economic evaluation.
4) Build Innisfil TS at 115 kV from Essa TS	★ Reconductor 115 kV Tx line E3/4B and extend ~6 km into Innisfil ★ Build new 115/27.6 kV 50/83 MVA station ★ Upgrade Essa TS 230/115 kV autotransformers	★ No thermal violations ★ No voltage violations	★ No need for LV capacitor banks within study period provided Alliston TS 10-day LTR is respected.	$132 M (Line ~30%, Station ~20%, Essa ~ 50%) Customer to pay for (at a minimum) the entire new Transformer station and the extended portion of the transmission line, dedicated to the customer. Cost allocation for the re-conductoring of E3/4B and the upgrading of Essa TS autotransformers is uncertain at this time. Subject to economic evaluation.
5) Build Innisfil TS at 230 kV via tapping E8/9V	★ Tap existing 230 kV circuits E8/9V near Alliston TS ★ Create new ROW Eastwards towards Innisfil ★ Decide if you need/can cross the 500 kV ROW ★ Build new 230/27.6 kV 50/83 MVA station	★ No thermal violations ★ No voltage violations	★ No need for LV capacitor banks within study period provided Alliston TS 10-day LTR is respected.	Highly dependent on new ROW.

6) Build Innisfil TS at 115 kV via circuit coming south from Barrie TS (or 230 kV with option #2 in place)	★ Current circuit being used as 44 kV feeder from Barrie TS ★ Circuit has capability to run at 115 kV ★ Work required to energize line at 115 kV to feed the new Innisfil TS	★ TBD	★ TBD	TBD

Table 2: Relief of Essa TS 500 kV Autotransformer Overloads – Assumed I/S date - TBD

Option	Description	Observation	Recommendation Going-Forward
1) Replace the existing 500/230 kV autotransformers at Essa TS with higher rated ones	★ Replace the existing autotransformers with ones with higher LTR values	★ T3 consists of 3 single phase units. ★ T3 becomes overloaded summer 2019 ★ T4 consists of 3 single phase units ★ T4 becomes overloaded summer 2024	★ Check to ensure that no single phase unit is more limiting than the other phases ★ Look into Hydro One's spare inventory being mindful of impedances ★ Check Lead-times for autotransformer purchasing ★ Check if a 3-phase unit replacement is appropriate
2) Install a 3rd 500/230 kV autotransformer at Essa TS		★ Would require some 230 kV breakers ★ Perhaps a 500 kV breaker ★ Unsure if room exists in the current Essa TS 500 kV yard	★ TBD

Table 3: Relief of Voltage Deficiencies Along M6/7E – Assumed I/S date 2012

Option	Description	Adverse Effects	Essa x Midhurst Line Overload	> 600 MW on M6/7E	Midhurst TS JQ bus - VD	Essa TS T3 & T4 500/230 kV autotransformers
1) Low Voltage Capacitor Banks at Midhurst TS BY bus & Orillia TS	★ Install 2 – 30 MX capacitor banks at Midhurst TS DESN #1 (BY buses) ★ Install 2 – 30 MX capacitor banks at Orillia TS	★ No new thermal violations ★ No new voltage violations	★ Postpones the line overload to the end of the study period 2023*	★ Does not impact the amount of MW load connected to M6/7E ★ M6/7E load exceeds 600 MW in Winter 2021	★ Slight improvement in voltage decline ★ Postpones the need for LV capacitors to 2023*	★ Postpones the need to upgrade T4 to beyond study period ★ Postpones the need to upgrade T3 by 1 year

*Note: With North Simcoe County upgrades
- ★ Additional transformation capacity (either Bracebridge TS or Muskoka TS)
- ★ Additional Var support (either Bracebridge TS or Muskoka TS)

Table 4: Short-Listed Options for Relief of M6/7E Line Overloads – Assumed I/S TBD

Option	Description	Adverse Effects	Essa x Midhurst Line Overload	> 600 MW on M6/7E (Winter 2021)	Minden TS x Cooper Falls Jct. Line Overload	Midhurst x Orillia Line Overload
1) Low Voltage Capacitor Banks at Midhurst TS BY bus & Orillia TS	★ Install 2 – 30 MX capacitor banks at Midhurst TS DESN #1 (BY buses) ★ Install 2 – 30 MX capacitor banks at Orillia TS	★ No new thermal violations ★ No new voltage violations	★ Without LV caps, the Need date is 2017 ★ With LV caps & Simcoe North upgrade, the Need date is postponed to 2023	★ Does not impact the amount of MW load connected to M6/7E	★ Without LV caps, the Need date is 2023 ★ With LV caps & Simcoe North upgrade, the Need date is not within the study period	★ Without LV caps, the Need date is 2024 ★ With LV caps & Simcoe North upgrade, the Need date is not within the study period
2) Re-conductor overloaded sections of M6/7E	★ Replace existing conductors with higher ampacity ones	★ TBD	★ After installing the LV caps, the Need date for the line overload is after the >600 MW rule Need date, hence re-conductoring may not be required.	★ Does not impact the amount of MW load connected to M6/7E	★ After installing the LV caps, the Need date for the line overload is after the >600 MW rule Need date, hence re-conductoring may not be required.	★ After installing the LV caps, the Need date for the line overload is after the >600 MW rule Need date, hence re-conductoring may not be required.
3) 1 x 230 kV Line between Essa TS x Midhurst TS	★ Widen the existing ROW and install a single 230 kV circuit ★ (Under normal conditions) Place	★ TBD	★ Overload should be resolved	★ Results in less than 550 MW of winter loading on M6/7E by the end of	★ After installing the LV caps, the Need date for the line overload is after the >600	★ TBD (overload should be resolved however, simulation recommended).

	half of entire Midhurst TS load onto new circuit; quarter of Midhurst TS load placed on M6E; quarter placed on M7E			★ the study period. ★ Impact to restoration TBD	MW rule Need date ★ TBD (must be simulated)	
4) In-line breakers	★ Sectionalize M6/7E to reduce flow on remaining circuits upon contingencies	★ TBD	★ Overload should be resolved (must be simulated)	★ If breakers place at Orillia TS, 5 DESN TS's would be split up (2/3, 3/2, or 2.5/2.5)	★ Overload should be resolved (must be simulated)	★ Overload should be resolved (must be simulated)
5) Tap E26/27 to resupply Midhurst TS	★ Tap E26/27 and create ~6 km of new ROW to Midhurst TS (M6/7E)	★ TBD	★ Overload should be resolved (must be simulated)	★ TBD via simulation however, the 600 MW rule will be not violated within the study period.	★ After installing the LV caps, the Need date for the line overload is after the >600 MW rule Need date ★ TBD (must be simulated)	★ TBD

Note: With North Simcoe County upgrades

- ★ Additional transformation capacity (either Bracebridge TS or Muskoka TS)
- ★ Additional Var support (either Bracebridge TS or Muskoka TS)

4. DISCUSSION OF PREFERRED OPTIONS

Since post-contingency voltage violations can occur as early as summer 2011, the preferred option is to install, as soon as possible, low voltage capacitor banks at Midhurst TS DESN #1 BY bus and Orillia TS. The installation of these low voltage capacitor banks, as well as solutions from the North/South Reinforcement Project, postpone many of the South Simcoe Needs. Figure 5 illustrates a timeline of the postponed Needs dates with Midhurst TS and Orillia TS capacitor banks are installed.

Three options were identified to supply Innisfil Hydro's load and alleviate the Alliston TS station overload which is forecast to occur as early as 2017:

1. Upgrade Alliston TS to a 75/125 MVA DESN station
2. Rebuild Barrie TS to a 230 kV 75/125 MVA DESN station
3. Build a new line and station into Innisfil

Based on historical costs and anticipated regulatory approval timelines, Innisfil Hydro has indicated that they tentatively prefer option 1. If Innisfil Hydro decides to pursue this option, low voltage capacitor banks will need to be installed at Alliston TS. Need date of these capacitor banks would likely not change. The second option—rebuilding Barrie TS—would require further study if it were to become Innisfil Hydro's preferred option, as this option would be driven by multiple needs and considerations (i.e., Barrie TS EOL, supply for multiple LDCs, potential GO Transit supply, expansion of transmission corridors, etc.).

Options to meet longer-term solutions were identified through this study but decisions as to which options are preferred were deferred by the study team as none of them would need to be committed before 2015.

5. RESULTING NEEDS TIMELINE & STAGING OF DEVELOPMENT PLAN

Resulting Needs Timeline

Figure 5 illustrates the postponed Need dates of M6E and M7E circuit overloads and 500/230 kV autotransformers at Essa TS after the installation of the low voltage capacitor banks at Midhurst TS DESN #1 and Orillia TS, in addition to the upgrades for the North/South Reinforcement Project. Furthermore, notice that the Need dates for the M6E/M7E circuit overloads are pushed beyond the Need date of load security off M6E/M7E. Figure 6 depicts the timeline once conservation is taken into account, further postponing the Need dates.

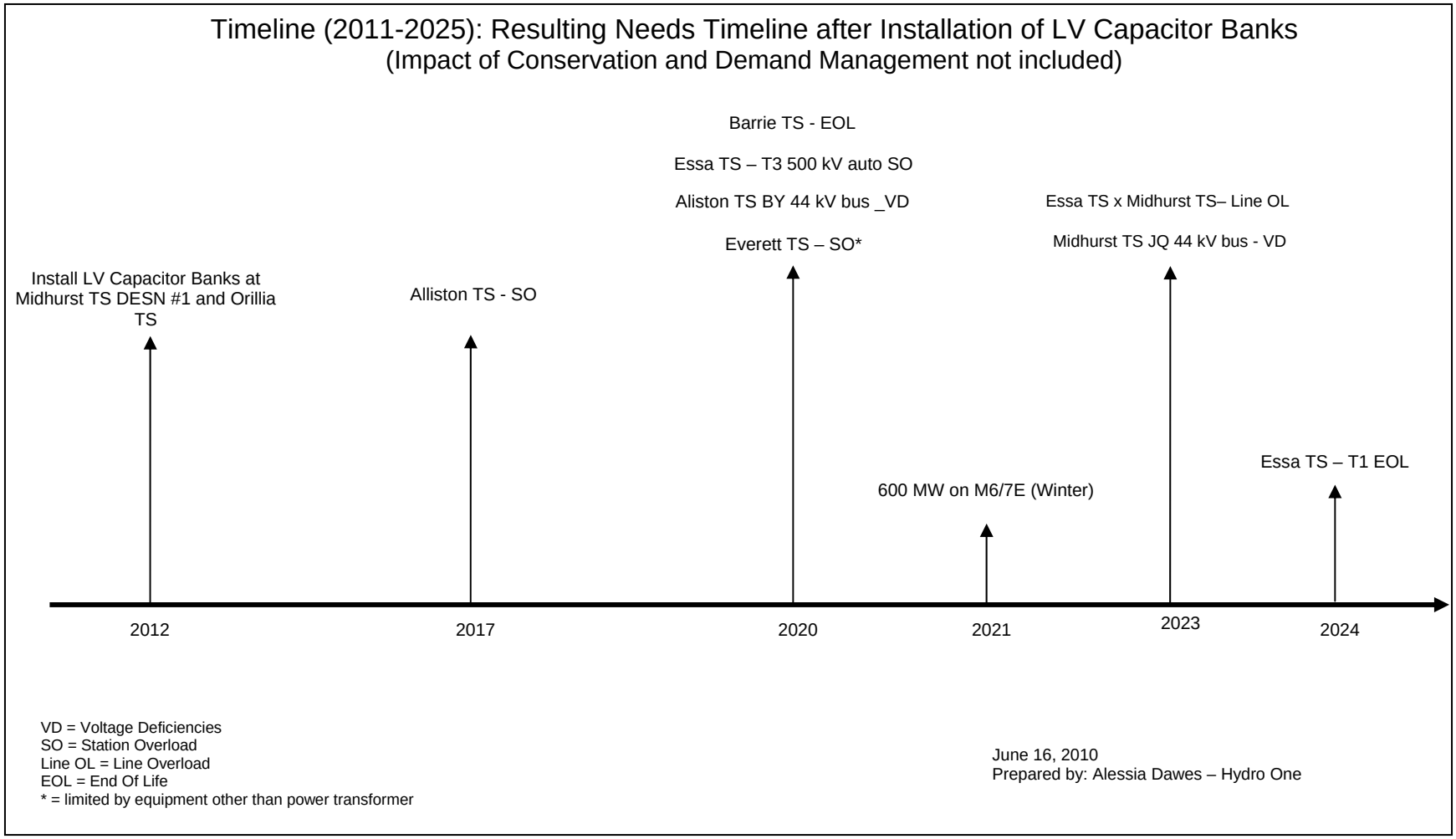


Figure 5: Resulting Needs Timeline with Installation of LV Capacitor Banks

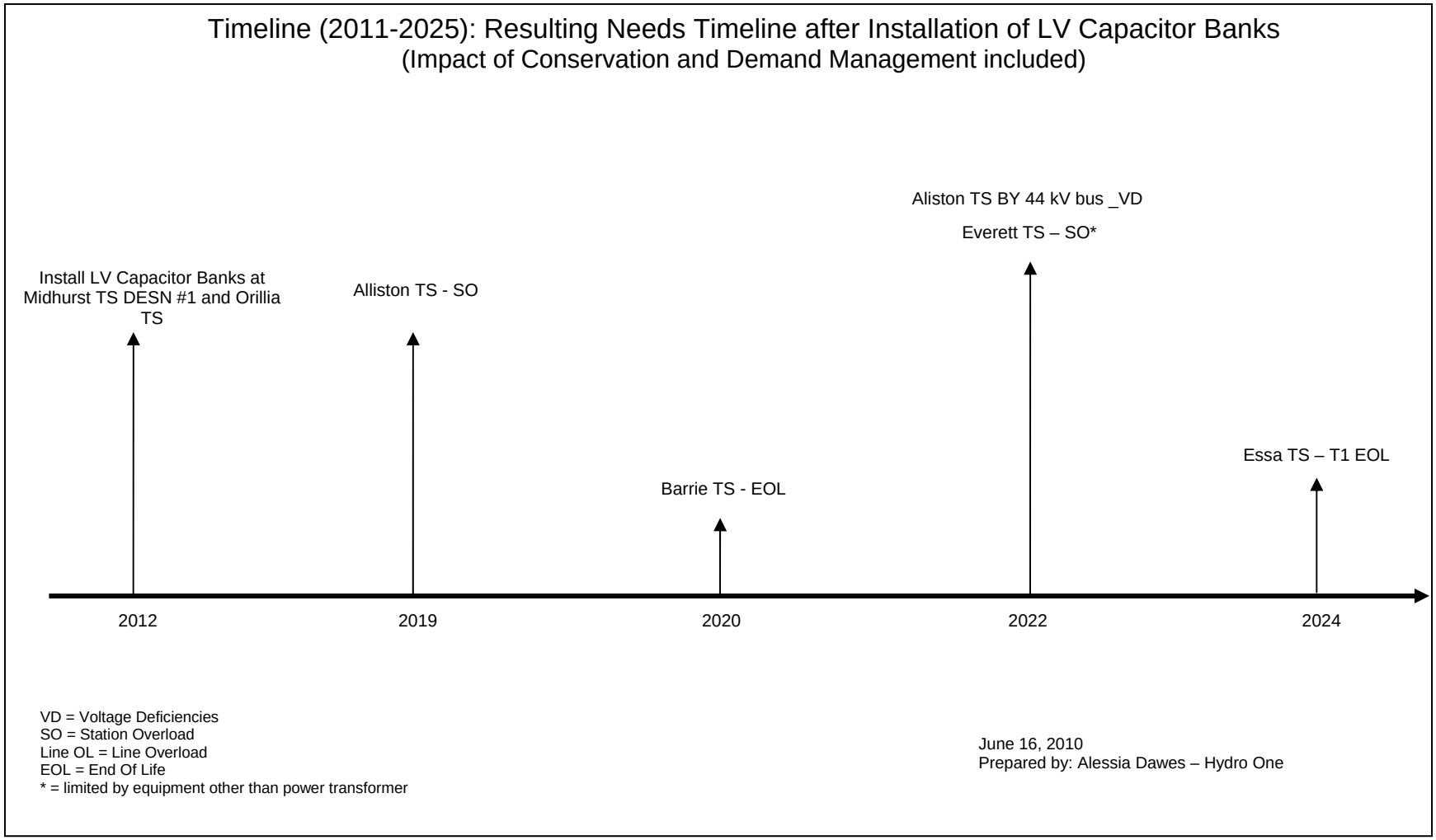


Figure 6: Resulting Needs Timeline with Installation of LV Capacitor Banks and impact of CDM

Staging of Development Plan

In view of the uncertainty associated with the load forecast as a result of the economic downturn, it is recommended that the preferred plan be implemented in stages as follows:

(1) Immediate Action: Install LV Capacitor Banks
Install low voltage capacitor banks at Midhurst TS DESN#1 and Orillia TS. This is to be placed in service by spring 2012.

(2) Medium-Term: Upgrade Alliston TS
This stage is to be placed in service by spring 2017 and should therefore be initiated no later than spring 2015 upon LDC request for additional transformation capacity. An addition to this project would be to place LV capacitor banks at Alliston TS in conjunction with the capacity upgrade. In the event the LDC determines that this is not their preferred option, further study of the identified alternatives (i.e., upgrading Barrie TS, or building a new Innisfil TS, and associated line construction) would be required.

(3) Long-term Needs:
A number of options to meet longer-term area supply needs were identified through this study, but as none of them need to be committed before 2015, a decision as to the preferred options was deferred for further study in 2014, or earlier if required. In view of the uncertainty associated with the economic recovery and therefore the load forecast, it is recommended that the load level in the entire Simcoe County be monitored to ensure that options are studied with enough lead time to meet needs as they arise. The following are some of the options identified in this study that may require further study as load continues to grow in the region:

1. Install additional 500/230 kV transformation capacity at Essa TS
2. Change CT ratio of Metering CTs at Everett TS
3. Install In-Line Breakers onto M6/7E
4. Replace End-Of-Life Equipment

Depending how the relief of Alliston TS station overload actually occurs, Hydro One may replace EOL equipment (like-for-like) at Barrie TS and Essa TS according to their work prioritization schedule. However, given the potential for further load growth and electrification of transit, it is recommended that options for Barrie TS EOL be studied in detail at the next iteration of this study.

6. CONCLUSIONS

The following conclusions can be reached from the analysis performed by this study.

- Midhurst TS as well as other stations connected along transmission line M6/7E experience post-contingency voltage deficiencies throughout the study period. Midhurst TS DESN#1 is expected to experience these voltage deficiencies as early as summer 2011. The earliest possible option to relieve this problem cannot be implemented until 2012.
- South Simcoe County requires additional transformation capacity for its growing load specifically in the Innisfil Hydro Service territory. The majority of Innisfil Hydro load is fed from Alliston TS. Alliston TS is expected to be loaded beyond its capacity limit in 2017. Several options have been developed to relieve Alliston TS.
- Sections of transmission line M6/7E become overloaded upon the loss of its companion circuit (post-contingency). Starting in 2017, the Essa TS by Midhurst TS section becomes overloaded. With conservation and the addition of low voltage capacitor banks at Midhurst TS and Orillia TS in addition of upgrades to Northern Simcoe County, the Need dates for these line overloads are postponed past 2025.
- The 500/230 kV auto-transformers at Essa TS are expected to be loaded to 100% of their capacity by 2020. However, when taking conservation into account, the transformers will not surpass their 10-day LTR within the study period.
- There will be greater than 600 MW of load served by transmission line M6E/M7E that could be load potentially lost due to configuration starting winter 2020/2021, but with conservation the loading remains below 600 MW throughout the study period. This would be a load security violation according to the IESO reliability criteria.

7. RECOMMENDATIONS

Several recommendations can be drawn from this study to address the current system deficiencies and provide system capacity to meet forecasted load growth. These recommendations are:

1. Hydro One Networks Inc. to install two low voltage capacitor banks at Midhurst TS DESN #1 as soon as possible.
2. Innisfil Hydro to officially request additional transformation capacity to Hydro One. Innisfil Hydro to initiate this request in time for Hydro One to obtain all necessary approvals for construction.
3. Hydro One Networks, the LDCs, and OPA to review the study in 2014 with updated Simcoe County load forecasts and to decide on appropriate actions to meet longer-term needs as they emerge.
4. The local electric utilities in Simcoe County and Hydro One to continue to monitor load growth and to review options for long-term growth based on location of new developments and load forecasts.
5. Hydro One to look a future options to enable M6E/M7E to meet load IESO's load restoration criteria.

APPENDIX A: South Simcoe Area Maps

Figure 1: Map of South Simcoe Area

Figure 2: Existing Transmission Facilities in South Simcoe Area

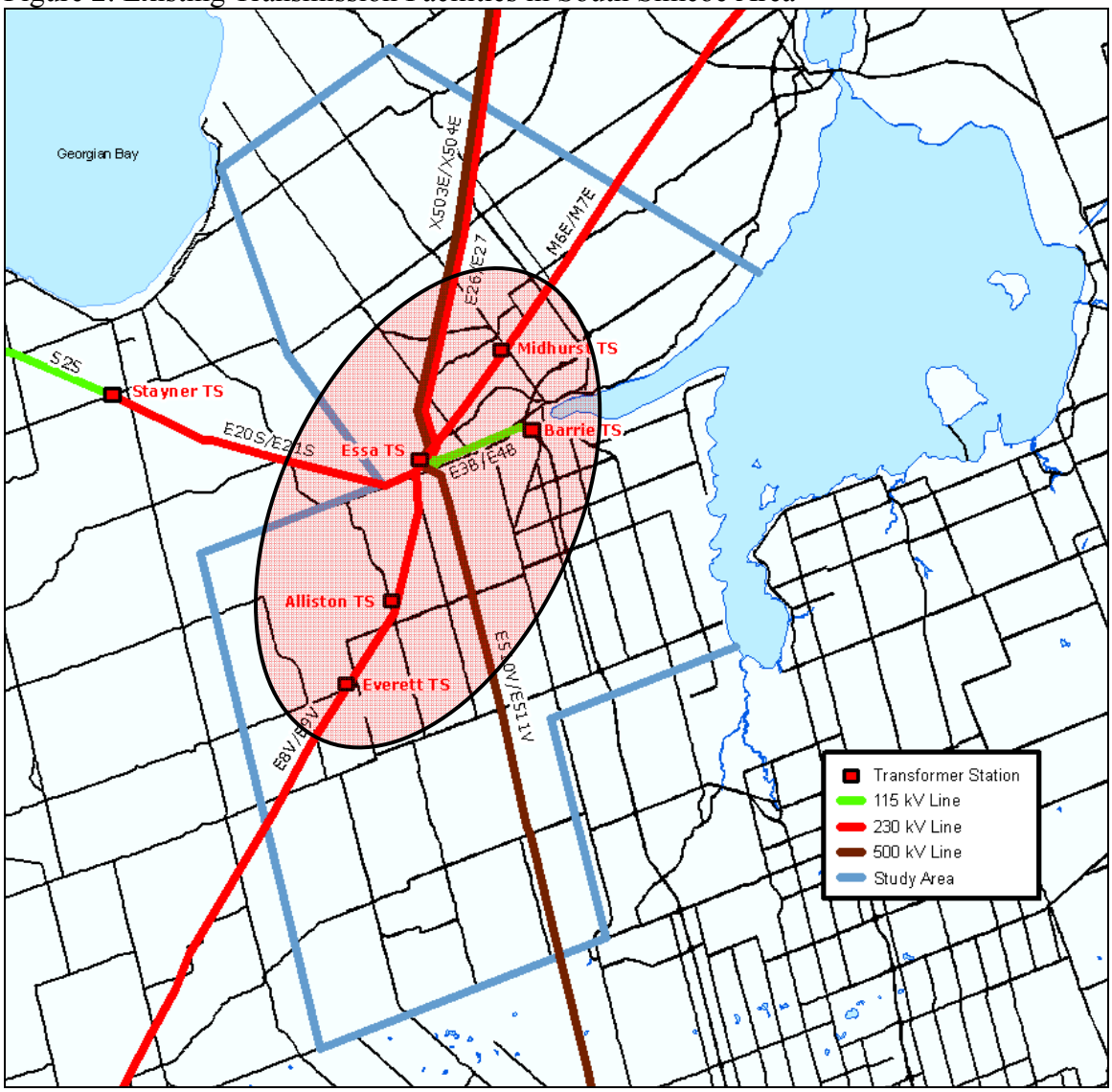
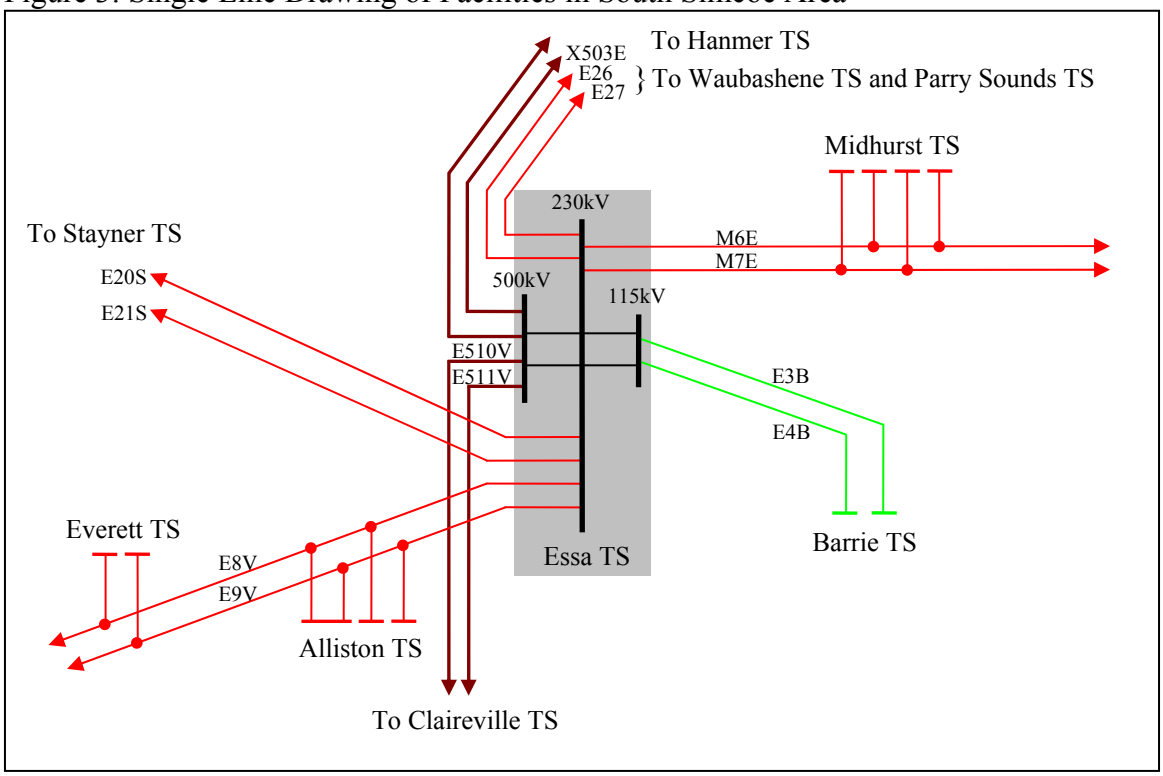


Figure 3: Single Line Drawing of Facilities in South Simcoe Area



APPENDIX B: Contracted Generation for South Simcoe area

Table 1a: Renewable Energy Standard Offer Program (RESOP) in the South Simcoe Area

Location	Nameplate Capacity by Type (MW)				Effective MW	Estimated i/s date
	Wind	Solar	Bioenergy	Total Contracted		
Alliston TS	-	-	-	-	-	-
Barrie TS	-	0.01	-	0.01	0.004	Mar/4/2008
Everett TS	-	-	-	-	-	-
Midhurst TS	0.004	-	-	0.004	0.0016	Aug/6/2011
Total	**0.004**	**0.01**	**0**	**0.014**	**0.0056**	

Data source: Ontario Power Authority

1. Effective MW calculated assuming 20% effective capacity for wind and 40% for solar generation, based on best available information

Table 1b: Feed-in Tariff (FIT) in the South Simcoe Area

Location	Nameplate Capacity by Type (MW)				Effective MW	Estimated i/s date
	Wind	Solar	Bioenergy	Total Contracted		
Alliston TS	-	-	-	-	-	-
Barrie TS	-	1.2	-	1.2	0.5	Dec/31/2012
Everett TS	-	0.8	-	0.8	0.3	Dec/31/2012
Midhurst TS	-	23.8	-	23.8	9.5	Dec/31/2012
Total	**0**	**25.8**	**0**	**25.8**	**10.3**	

Data source: Ontario Power Authority

1. Effective MW calculated assuming 40% for solar generation, based on best available information.
2. This table summarizes all contracted FIT generation at the time of writing. This includes all Capacity-Allocation-Exempt (CAE) applications received as of June 4, 2010, and all non-CAE applications received during the FIT program Launch Period (Oct 1 – Nov 30, 2010) that were offered contracts.

APPENDIX C: Simcoe County Demand Forecasts

Table 2a: Summer Load Forecast for South Simcoe Area (MVA): "Area" peak demand based on median growth and normal weather

	STN LTR	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Alliston TS Forecast	111.9	79.5	81.7	85.3	92.7	101.3	109.2	116.6	124.1	132.2	139.5	147.7	155.9	164.0	172.2	180.4
Alliston TS Conservation	111.9	2.7	4.2	5.9	7.5	8.7	9.9	11.1	12.2	13.1	13.8	14.6	15.2	15.8	16.2	16.6
Alliston TS Net Load	111.9	76.8	77.5	79.4	85.2	92.6	99.3	105.5	111.9	119.1	125.7	133.1	140.7	148.2	156.0	163.8
Barrie TS Forecast	115.0	78.9	80.8	82.8	84.8	86.8	88.8	90.8	92.9	95.1	97.3	99.6	101.9	104.2	106.7	109.2
Barrie TS Conservation	115.0	3.1	4.8	6.7	8.5	9.8	11.2	12.5	13.7	14.7	15.6	16.4	17.2	17.8	18.3	18.7
Barrie TS Net Load	115.0	75.8	76.0	76.1	76.3	77.0	77.6	78.3	79.2	80.4	81.7	83.2	84.7	86.4	88.4	90.5
Everett TS Forecast	117.0	76.3	78.3	80.4	82.4	84.9	87.3	89.9	92.6	95.4	98.2	101.2	104.1	107.3	110.5	113.3
Everett TS Conservation	117.0	1.3	2.0	2.8	3.5	4.1	4.6	5.2	5.7	6.1	6.4	6.8	7.1	7.3	7.6	7.7
Everett TS Net Load	117.0	75.0	76.3	77.6	78.9	80.8	82.7	84.7	86.9	89.3	91.8	94.4	97.0	100.0	102.9	105.6
Midhurst TS Forecast	339.4	238.9	241.5	244.5	247.5	250.4	253.5	256.6	259.8	262.9	266.3	269.6	273.2	276.7	280.3	284.0
Midhurst TS Conservation	339.4	7.1	11.0	15.4	19.6	22.7	25.7	28.8	31.6	34.0	35.9	37.8	39.5	40.9	42.2	43.1
Midhurst TS Net Load	339.4	231.8	230.5	229.1	227.9	227.7	227.8	227.8	228.2	228.9	230.4	231.8	233.7	235.8	238.1	240.9
Total Area Load Forecast		**473.6**	**482.3**	**493.0**	**507.4**	**523.4**	**538.8**	**553.9**	**569.4**	**585.6**	**601.4**	**618.1**	**635.0**	**652.3**	**669.6**	**687.0**
Total Area Conservation		**14.1**	**22.0**	**30.8**	**39.1**	**45.3**	**51.4**	**57.6**	**63.1**	**67.9**	**71.8**	**75.5**	**79.0**	**81.8**	**84.3**	**86.2**
Total Area Net Load		**459.5**	**460.3**	**462.2**	**468.3**	**478.1**	**487.4**	**496.3**	**506.3**	**517.7**	**529.6**	**542.6**	**556.0**	**570.5**	**585.3**	**600.8**

Data sources: Hydro One-Dx, PowerStream Inc., Innisfil Hydro, and Ontario Power Authority

Station LTR: Summer 10-day Limited Time Ratings

Conservation forecasts include LDC/OPA energy efficiency and demand response programs, and the effects of codes & standards and time-of-use rates. Energy efficiency/demand response savings from transmission-connected industrial customers are not included in the forecast. The conservation forecast is an allocation of the province-wide forecast to the local area; demand savings are coincident with IESO system peak.

Table 2b: Summer Load Forecast for other stations in Simcoe County (MVA): "Area" peak demand based on median growth and normal weather

	STN LTR	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Bracebridge TS Forecast	95.0	33.0	33.1	33.1	33.1	33.2	33.2	33.3	33.3	33.4	33.4	33.4	33.5	33.5	33.6	33.6
Bracebridge TS Conservation	95.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Bracebridge TS Net Load	95.0	33.0	33.1	33.1	33.1	33.2	33.2	33.3	33.3	33.4	33.4	33.4	33.5	33.5	33.6	33.6
Muskoka TS Forecast	153.9*	138.7	140.5	142.3	144.2	146.0	147.9	149.9	151.9	153.8	155.8	157.8	159.9	162.0	164.1	166.2
Muskoka TS Conservation	153.9*	3.8	6.0	8.4	10.6	12.3	14.0	15.7	17.2	18.4	19.5	20.5	21.5	22.2	22.9	23.4
Muskoka TS Net Load	153.9*	134.9	134.5	133.9	133.6	133.7	133.9	134.2	134.7	135.4	136.3	137.3	138.4	139.8	141.2	142.8
Orillia TS Forecast	165.2	112.1	114.3	116.6	118.9	121.3	123.8	126.2	128.8	131.3	134.0	136.6	139.4	142.2	145.0	147.9
Orillia TS Conservation	165.2	4.0	6.3	8.9	11.2	13.0	14.7	16.5	18.1	19.5	20.6	21.7	22.7	23.5	24.2	24.7
Orillia TS Net Load	165.2	108.1	108.0	107.7	107.7	108.3	109.1	109.7	110.7	111.8	113.4	114.9	116.7	118.7	120.8	123.2
Parry Sound TS Forecast	52.2	43.9	44.1	44.4	44.6	44.8	45.0	45.2	45.4	45.6	46.0	46.2	46.4	46.6	46.8	47.0
Parry Sound TS Conservation	52.2	1.6	2.4	3.4	4.3	5.0	5.7	6.4	7.0	7.5	7.9	8.4	8.7	9.1	9.3	9.5
Parry Sound TS Net Load	52.2	42.3	41.7	41.0	40.3	39.8	39.3	38.8	38.4	38.1	38.1	37.8	37.7	37.5	37.5	37.5
Stayner TS Forecast	191.5	107.3	109.1	111.0	112.9	114.8	116.7	118.7	119.7	120.6	121.6	122.6	123.5	124.5	125.5	126.5
Stayner TS Conservation	191.5	3.5	5.4	7.6	9.7	11.2	12.7	14.2	15.6	16.8	17.8	18.7	19.5	20.2	20.9	21.3
Stayner TS Net Load	191.5	103.8	103.7	103.4	103.2	103.6	104.0	104.5	104.1	103.8	103.8	103.9	104.0	104.3	104.6	105.2
Waubaushene TS Forecast	99.6	89.2	90.6	91.9	93.3	94.7	96.1	97.6	99.0	100.5	102.0	103.6	105.1	106.7	108.3	109.9
Waubaushene TS Conservation	99.6	3.4	5.2	7.4	9.3	10.8	12.3	13.8	15.1	16.2	17.1	18.0	18.8	19.5	20.1	20.6
Waubaushene TS Net Load	99.6	85.8	85.4	84.5	84.0	83.9	83.8	83.8	83.9	84.3	84.9	85.6	86.3	87.2	88.2	89.3
Alliston TS T2** Forecast	99.9	44.0	44.0	44.0	44.0	44.0	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3
Alliston TS T2** Conservation	99.9	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Alliston TS T2** Net Load	99.9	44.0	44.0	44.0	44.0	44.0	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3
Total Area Load Forecast		**568.2**	**575.7**	**583.2**	**591.0**	**598.8**	**610.0**	**618.1**	**625.3**	**632.6**	**640.0**	**647.4**	**655.0**	**662.7**	**670.5**	**678.4**
Total Area Conservation		**16.3**	**25.4**	**35.6**	**45.2**	**52.3**	**59.4**	**66.6**	**72.9**	**78.4**	**83.0**	**87.3**	**91.2**	**94.6**	**97.4**	**99.6**
Total Area Net Load		**551.9**	**550.3**	**547.6**	**545.8**	**546.5**	**550.6**	**551.5**	**552.4**	**554.2**	**557.0**	**560.1**	**563.8**	**568.1**	**573.1**	**578.8**

Data sources: Hydro One-Dx and Ontario Power Authority

Station LTR: Summer 10-day Limited Time Ratings

Bracebridge TS does not have conservation estimate as it does not serve LDC load

* LTR limited by a low voltage current transformer and post-contingency voltage problems

** Transformer dedicated to an Industrial customer

Conservation forecasts include LDC/OPA energy efficiency and demand response programs, and the effects of codes & standards and time-of-use rates. Energy efficiency/demand response savings from transmission-connected industrial customers are not included in the forecast. The conservation forecast is an allocation of the province-wide forecast to the local area; demand savings are coincident with IESO system peak.

Table 3a: Summer Load Forecast for Load Security Analysis of Load Connected to Circuits M6/7E (MW)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Bracebridge TS Forecast	33.0	33.1	33.1	33.1	33.2	33.2	33.3	33.3	33.4	33.4	33.4	33.5	33.5	33.6	33.6
Bracebridge TS Conservation	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Bracebridge TS Net Load	33.0	33.1	33.1	33.1	33.2	33.2	33.3	33.3	33.4	33.4	33.4	33.5	33.5	33.6	33.6
Muskoka TS Forecast	138.7	140.5	142.3	144.2	146.0	147.9	149.9	151.9	153.8	155.8	157.8	159.9	162.0	164.1	166.2
Muskoka TS Conservation	3.8	6.0	8.4	10.6	12.3	14.0	15.7	17.2	18.4	19.5	20.5	21.5	22.2	22.9	23.4
Muskoka TS Net Load	134.9	134.5	133.9	133.6	133.7	133.9	134.2	134.7	135.4	136.3	137.3	138.4	139.8	141.2	142.8
Orillia TS Forecast	112.1	114.3	116.6	118.9	121.3	123.8	126.2	128.8	131.3	134.0	136.6	139.4	142.2	145.0	147.9
Orillia TS Conservation	4.0	6.3	8.9	11.2	13.0	14.7	16.5	18.1	19.5	20.6	21.7	22.7	23.5	24.2	24.7
Orillia TS Net Load	108.1	108	107.7	107.7	108.3	109.1	109.7	110.7	111.8	113.4	114.9	116.7	118.7	120.8	123.2
Midhurst TS Forecast	238.9	241.5	244.5	247.5	250.4	253.5	256.6	259.8	262.9	266.3	269.6	273.2	276.7	280.3	284.0
Midhurst TS Conservation	7.1	11.0	15.4	19.6	22.7	25.7	28.8	31.6	34.0	35.9	37.8	39.5	40.9	42.2	43.1
Midhurst TS Net Load	231.8	230.5	229.1	227.9	227.7	227.8	227.8	228.2	228.9	230.4	231.8	233.7	235.8	238.1	240.9
Total Area Load Forecast	**522.7**	**529.4**	**536.5**	**543.7**	**550.9**	**558.4**	**566**	**573.8**	**581.4**	**589.5**	**597.4**	**606**	**614.4**	**623**	**631.7**
Total Area Conservation	**14.9**	**23.3**	**32.7**	**41.4**	**48.0**	**54.4**	**61.0**	**66.9**	**71.9**	**76.0**	**80.0**	**83.7**	**86.6**	**89.3**	**91.2**
Total Area Net Load	**507.8**	**506.1**	**503.8**	**502.3**	**502.9**	**504**	**505**	**506.9**	**509.5**	**513.5**	**517.4**	**522.3**	**527.8**	**533.7**	**540.5**

Bracebridge TS does not have conservation estimate as it does not serve LDC load

Note: Numbers highlighted in RED indicate loading on M6E/M7E above 600MW which violates IESO's load security criteria

Conservation forecasts include LDC/OPA energy efficiency and demand response programs, and the effects of codes & standards and time-of-use rates. Energy efficiency/demand response savings from transmission-connected industrial customers are not included in the forecast. The conservation forecast is an allocation of the province-wide forecast to the local area; demand savings are coincident with IESO system peak.

Table 3b: Winter Load Forecast for Load Security Analysis of Load Connected to Circuits M6/7E (MW)

	2010 2011	2011 2012	2012 2013	2013 2014	2014 2013	2015 2016	2016 2017	2017 2018	2018 2019	2019 2020	2020 2021	2021 2022	2022 2023	2023 2024	2024 2025
Bracebridge TS Forecast	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Bracebridge TS Conservation	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Bracebridge TS Net Load	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Muskoka TS Forecast	169.2	171.4	173.6	175.9	178.1	180.5	182.8	185.2	187.6	190.0	192.5	195.0	197.5	200.1	202.7
Muskoka TS Conservation	3.8	6.0	8.4	10.6	12.3	14.0	15.7	17.2	18.4	19.5	20.5	21.5	22.2	22.9	23.4
Muskoka TS Net Load	165.4	165.4	165.2	165.3	165.8	166.5	167.1	168	169.2	170.5	172	173.5	175.3	177.2	179.3
Orillia TS Forecast	118	120.4	122.8	125.2	127.7	130.3	132.9	135.5	138.3	141.0	143.8	146.7	149.7	152.6	155.7
Orillia TS Conservation	4.0	6.3	8.9	11.2	13.0	14.7	16.5	18.1	19.5	20.6	21.7	22.7	23.5	24.2	24.7
Orillia TS Net Load	114	114.1	113.9	114	114.7	115.6	116.4	117.4	118.8	120.4	122.1	124	126.2	128.4	131
Midhurst TS Forecast	195.1	199.6	204.3	209.1	214.0	218.7	223.6	228.5	233.6	238.8	244.1	249.6	257.5	265.6	273.9
Midhurst TS Conservation	7.1	11.0	15.4	19.6	22.7	25.7	28.8	31.6	34.0	35.9	37.8	39.5	40.9	42.2	43.1
Midhurst TS Net Load	188	188.6	188.9	189.5	191.3	193	194.8	196.9	199.6	202.9	206.3	210.1	216.6	223.4	230.8
Total Area Load Forecast	**512.3**	**521.4**	**530.7**	**540.2**	**549.9**	**559.5**	**569.3**	**579.3**	**589.5**	**599.9**	**610.5**	**621.3**	**634.7**	**648.4**	**662.3**
Total Area Conservation	**14.9**	**23.3**	**32.7**	**41.4**	**48**	**54.4**	**61**	**66.9**	**71.9**	**76**	**80**	**83.7**	**86.6**	**89.3**	**91.2**
Total Area Net Load	**497.4**	**498.1**	**498**	**498.8**	**501.9**	**505.1**	**508.3**	**512.4**	**517.6**	**523.9**	**530.5**	**537.6**	**548.1**	**559.1**	**571.1**

Bracebridge TS does not have conservation estimate as it does not serve LDC load

Note: Numbers highlighted in RED indicate loading on M6E/M7E above 600MW which violates IESO's load security criteria

Conservation forecasts include LDC/OPA energy efficiency and demand response programs, and the effects of codes & standards and time-of-use rates. Energy efficiency/demand response savings from transmission-connected industrial customers are not included in the forecast. The conservation forecast is an allocation of the province-wide forecast to the local area; demand savings are coincident with IESO system peak.

APPENDIX 7

Innisfil Hydro Distribution Systems Ltd.

Review of Innisfil Hydro's 2011 Asset Management Plan

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Private and Confidential

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Innisfil Hydro Distribution Systems Ltd.

Review of the 2011 Asset Management Plan

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EXECUTIVE SUMMARY

In preparation for its Cost of Service rate application, Innisfil Hydro Distribution System Ltd. ("Innisfil Hydro") has engaged AESI to review, provide commentary and make recommendations on its 2011 Asset Management Plan. The Asset Management Plan, and requirements, is defined in the Ontario Energy Board's Filing Requirements for Transmission and Distribution Applications, specifically in Chapter 2. AESI reviewed the Asset Management Plan and provided a draft of its comments and recommendations, based on the defined Ontario Energy Board requirements and on its experience in assisting other Local Distribution Companies to develop their Asset Management Plans. In response to the draft, Innisfil Hydro provided its Business Plan 2011 for years 2012 to 2016 for consideration and with respect to the comments and recommendations presented in this review.

The existing 2011 Asset Management Plan includes a good narrative of Innisfil Hydro's asset management practices, relevant data and appropriate references to the OEB's Distribution Code. However, the Asset Management Plan should provide additional information regarding maintenance practices and the utility's means and methodology for documenting, reviewing and analyzing inspection and maintenance data in order to identify and prioritize capital expenditures. With regards to capital expenditures, the Asset Management Plan should include a three year forecast (test year plus two subsequent years) of each capital project and estimated expenditures. A five year (2012 to 2016 inclusive) forecast of engineering capital expenditures is presented within the Business Plan, the details of which should be included within the Asset Management Plan as noted in this review.

Further, the Asset Management Plan should explicitly state whether Innisfil Hydro has undertaken any asset condition studies and should include such studies as an appendix to the Asset Management Plan.

Much of the content of the existing Asset Management Plan and relevant sections of the Business Plan may be leveraged and included, as further discussed in this report, within the following framework:

1. Overview of the Distribution System
2. Asset Management Objectives
3. Approach to Managing Assets
4. Identifying and Prioritizing Projects
5. Capital Budget Items
6. Forecasted Capital Expenditures

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1 INTRODUCTION

The Ontario Energy Board ("OEB") has established Filing Requirements for Transmission and Distribution Applications ("Filing Requirements") in which it "Sets out the standards for transmitters and distributors to follow when filing for rate adjustments, leave to construct approvals, and conservation funding." Chapter 2 of the Filing Requirements specifically addresses a Cost of Service ("CoS") rate application for transmission and distribution companies. In June 2011 Chapter 2 was revised and now requires an Asset Management Plan to be included in Exhibit 2 (Rate Base) of the CoS application.

Following are the minimum requirements of an asset management plan, as outlined in Section 2.5.2.2 of Chapter 2:

- The applicant must provide a formal asset management plan, if the applicant has such a plan. If not, an explanation as to why the applicant does not have such a plan must be provided. The applicant must also state whether or not it is planning to have one in place in the future.
- In the absence of an asset management plan, the applicant must provide information outlining its approach to the planning and prioritization of capital projects.
- The applicant must also provide, at minimum, a three year forecast of capital expenditures (test year plus two subsequent years).
- The applicant must also state whether or not it has undertaken any asset condition studies and, if so, copies of such studies must be filed.

To provide support for its future Ontario Energy Board rate filings Innisfil Hydro Distribution Systems Ltd. ("Innisfil Hydro") has recognized the importance of comprehensive asset management planning to capture and potentially expand on its existing asset management activities. Innisfil Hydro has also recognized that it is now required to have a documented Asset Management Plan as part of its CoS rate application in August 2012. As such, it has developed an Asset Management Plan and has engaged AESI to review, provide commentary and make recommendations on the 2011 Asset Management Plan.

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2 OBSERVATIONS AND ASSESSMENT

The assessment of Innisfil Hydro's 2011 Asset Management Plan is presented below and is based on AESI's knowledge and experience with similar Local Distribution Companies ("LDCs") and its understanding of the OEB requirements of an Asset Management Plan.

The existing 2011 Asset Management Plan includes a good narrative of Innisfil Hydro's asset management practices, relevant data and appropriate references to the OEB's Distribution Code. Innisfil's Asset Management Plan presents seven main sections, each of which provides an overview of an asset category; these include overhead lines, underground lines, distribution stations, metering, vehicles, property and equipment. Within each of these sections, the applicable assets and relevant asset management practices are described. For example, the overhead lines section includes a description of vegetation management, infrared thermography, line patrol, pole inspection and testing, protective device inspection, transformer inspection, voltage regulator inspection, capacitor inspection, fault indicator inspection and load balancing. Within these sections, Innisfil Hydro presents general consequences of not remediating deficiencies identified during inspection, providing support for expenditures. The narrative of maintenance practices within these sections, however, should be elaborated to further detail condition-based maintenance[1] activities or other preventive maintenance[2] activities, such as insulator washing, if performed. Innisfil Hydro could also include a brief description of its method of documenting inspection and maintenance data.

Some of the descriptions of asset management practices within the plan include a brief statement about the associated estimated expense that *would* be required but may not indicate whether the expenditure is planned for the bridge year or subsequent years; alternatively, it may state that the cost has been budgeted into a specific account, but does not identify the cost. Further, the Asset Management Plan often states that the cost has not been budgeted for in 2012 (or in subsequent years); it is not clear from this latter statement whether it is required or should

[1] Maintenance performed after inspection or other maintenance (e.g. infrared thermography) indicates impending failure or degradation in performance or condition of the asset. Condition-based maintenance serves to eliminate opportunity of breakdowns and reduce deviations from optimum asset performance.
[2] Maintenance performed at predetermined intervals or according to prescribed criteria and intended to reduce the probability of failure.

be included in forecasts. As such, the existing asset management plan does not adequately address the OEB's requirement to provide a three year forecast of capital expenditures.

Innisfil Hydro's Business Plan, however, provides a five year (2012 – 2016) forecast of capital expenditures, although only engineering capital expenditures are outlined; the forecast should not be restricted to engineering capital expenditures but capital expenditures of the utility. Furthermore, there should be a clear correlation between the costs presented in the Asset Management Plan and those in the engineering capital budget forecast of the Business Plan. It is imperative that there is consistency between any data, financial or otherwise, presented to the OEB and particularly between the Asset Management Plan and Business Plan.

Also not clearly documented within the plan is a description of how data from these asset management practices is reviewed, analyzed and used for identifying and prioritizing capital expenditures. Therefore, the plan does not adequately address the OEB's requirement to provide information outlining its approach to the planning and prioritization of capital projects.

Lastly, the existing plan does not state whether or not Innisfil has undertaken any asset condition studies; this should be clearly identified within the plan and if such studies have been performed, the results should be included as an appendix to the plan.

3 RECOMMENDATIONS

3.1 General

i. The Asset Management Plan should, as prescribed, include a minimum 3 year forecast of capital expenditures (test year plus two subsequent years) for the utility. Chapter 2 (Section 2.5.2.1) identifies capital expenditure information that should be provided on a project specific basis. While this information is required only for capital expenditures over the past five historical years, the bridge year and the test year (note that test year is required in the Asset Management Plan), Innisfil Hydro should consider providing this information for the two years subsequent to the test year. As noted above, there should be a clear correlation and consistency between the costs presented in the Asset Management Plan and those in the forecasts of the Business Plan.

ii. The Asset Management Plan should clearly demonstrate age and condition classification of particular assets if replacement of aging infrastructure is a significant component of the Plan and, as such, a large increase in capital expenditures, compared to historical expenditures, is required to replace those assets near or at the end of their useful life. For

example, a utility may have experienced a steady, modest growth rate in the 1950s and 1960s that was reflected in the installation of equipment such as wood poles.

When the community growth accelerated in the 1970s there was a correspondingly large increase in the number of wood poles installed. Historically, pole replacement may have been a modest capital expenditure as poles from the 1950s and 1960s came to the end of their useful life. The much larger number of poles installed in the 1970s may only now require replacement, thus creating a larger increase in capital expenditures to maintain high quality standards of safety and reliability. Demonstration of this aging characteristic is a critical recommendation to avoid non-approval of proposed expenditures based on historical patterns. Graphical representation of the age of particular assets creates an immediate appreciation of this trend.

iii. The Asset Management Plan should clearly state whether or not Innisfil Hydro has undertaken any asset condition studies; if such studies have been performed, Innisfil Hydro should include the results as an appendix to its Asset Management Plan. In AESI's experience, the asset condition studies are those studies performed beyond the routine practices (i.e. inspection and maintenance) to assess asset condition.

iv. As noted above, documentation of maintenance practices within the Asset Management Plan should be elaborated to further detail condition-based maintenance or other preventive maintenance practices, such as insulator washing, as applicable.

v. Innisfil Hydro should ensure that inspection cycles defined within the Asset Management Plan are consistent with the OEB's minimum inspection requirements.

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3.2 Structure

Much, if not all, content in the existing asset management plan could be leveraged to develop a plan that is more aligned, in our experience, with the OEB's expectations and with those Asset Management Plans presented with minimal to no associated interrogatories. The following presents a framework that Innisfil Hydro could adopt for its Asset Management Plan.

1. Overview of the Distribution System

This section should include a description of the service area, number and type of customers, primary and secondary voltages, conductor/cable lengths, meter types, etc. Some of the 'Background' content within the Business Plan could be leveraged for this section.

2. Asset Management Objectives

This section should identify Innisfil Hydro's objectives for managing its assets. Typical objectives include, but are not limited to, ensuring customer and employee safety, providing a reliable system while improving reliability indices, accounting for future load growth and ensuring appropriate future supply, addressing legislature or regulatory directives, etc. Several sections within the Business plan address such items, although not explicitly defined as asset management objectives. For example, both the 'Background' and Section 1 discuss population and customer growth. These should be included within the Asset Management Plan and elaborated on with respect to capital expansion and additional funding that may be required to accommodate the expansion of Innisfil Hydro's distribution infrastructure.

3. Approach to Managing Assets

Innisfil Hydro could utilize the current format in which it identifies assets and describes inspection and maintenance practices, based on the overhead distribution system, underground distribution system, substations, metering, vehicles, property and equipment. Further, and as noted above, Innisfil Hydro presents the consequences of not remediating deficiencies identified during inspection; this information is well presented and relevant as it relates Innisfil's approach to managing assets to achieving objectives. When appropriate, the significance of aging infrastructure should be emphasized within this section. This can be critical to the immediate budgetary requirements but also demonstrates the long-term

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commitment to maintain high quality infrastructure. Graphical representation clarifies the history of the particular asset and demonstrates the anticipated trends.

4. Identifying and Prioritizing Projects

Within this section, Innisfil Hydro should describe its approach to identifying projects within the capital budget. In our experience with utilities of Innisfil's size, the approach is informal and essentially encompasses review and analysis of inspection data, maintenance data, age classifications, system reliability data and regulatory and municipal drivers. The methodology may also comprise analysis of leading indicators of the 'health' of the system, such as load forecasting and system planning. Innisfil Hydro should also describe any risk, cost/benefit or other analysis performed to identify projects for inclusion in the capital budget.

This section should also describe the approach to prioritizing projects and therefore expenditures. For example, projects meeting multiple objectives may be assigned a high priority as compared to a project achieving a single objective. Also as an example, a pole line rebuild may be considered less of a priority than spot pole replacements presenting safety concerns. It should be noted that Innisfil's approach need not be complicated or involve formal risk assessment methods. However, it should be clear in explaining that Innisfil has a process in place in which it reviews system data and considers objectives to determine priorities. Section 5 of the Business Plan identifies the priorities of capital and operations and maintenance programs. This information could be leveraged and elaborated upon within the Asset Management Plan to provide further information about these priorities with respect to asset management objectives and developing the capital budget.

5. Capital Budget Items

This section should explain that the capital budget is developed following the approach to identifying and prioritizing projects, and therefore expenditures; it should also reiterate that spending is prioritized to achieve asset management objectives. Further, a listing and description of key categories, and OEB Uniform System of Account ("USoA") codes within each category, should be included. Examples of categories may include, but are not limited to, buildings and land, stations, underground distribution, overhead distribution, transformers, meters, office equipment, hardware and software, vehicles, tools, etc.

Programs may be defined within the categories. For example, the stations category may include a program for system expansion and a program for replacement or upgrades due to age or condition; similarly, the overhead distribution category may include programs such

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as relocation of hydro plant due to municipal drivers, replacement or upgrade of plant due to age or condition, and expansion to supply new development.

The Business Plan provides an itemized engineering budget forecast over a five year period; the items listed appear to be individual programs that could be included within this section of the Asset Management Plan, as noted below. Programs are further itemized to identify projects (further described below).

Innisfil Hydro should also include a description of each program. Section 5 of the Business Plan provides good information that may be leveraged within the Asset Management Plan. For example, the replacement of aged switches with automated switches is discussed. Again, this should be expanded upon within the Asset Management Plan to identify the risks of such aged infrastructure, including a description of how the program meets a defined asset management objective(s), the benefits of the proposed program and the consequences of not expending capital funds (i.e. implementing the program).

Generally, Innisfil Hydro should clearly articulate the impact of these programs to its distribution system and the customers it serves and justify its request for added funding such that the OEB may deem Innisfil Hydro prudent in its spending and may support a rate increase.

Below is a brief example of what may be presented within this section of the asset management plan.

1. Category: Overhead Distribution

This category includes OEB USoA codes 1830, 1835 and 1855.

1.1. Program: Relocation of Hydro Plant Due to Municipal Drivers

Relocation of overhead plant that is currently situated where road-widening is proposed. Projects within this program are generally non-discretionary and mandated by the Town of Innisfil.

1.2. Program: Replacement or Upgrade Due to Age or Condition

Replacement of overhead assets in poor condition as noted in pole-line inspection records. Also includes replacement and upgrade of open-wire secondary with triplex service wire.

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6. Forecasted Capital Expenditures

As noted above, programs are further itemized to identify projects. Projects within capital budget should be identified for the test year (the prospective rate year) and subsequent two years. Each capital project should include at least the project cost, scope of work (i.e. description of the project) and business case (i.e. project justification/reason for completing the project).

In addition to the narrative, forecasted capital expenditures should be presented in table format, as has been included in well-documented asset management plans.

Below is an example of what may be presented within this section of the asset management plan. The categories and descriptions are guides and not intended to be all-inclusive.

Project 1: Relocation of Overhead Pole Line on Yonge St. between Victoria St. and Innisfil Beach Rd.

Capital Budget Amount: $102,000.

Project	Total	1830	1835	1840	1845	1850
Project 1	$102,000	$67,000	$12,000	$11,000	$10,000	$2,000

Scope of Work:

Business Case:

Category	Test Year	Test Year + 1	Test Year + 2
Buildings	$ (total)	$ (total)	$ (total)
Land	$ (total)	$ (total)	$ (total)
Stations	$ (total)	$ (total)	$ (total)
Underground Distribution	$ 21,000	$ (total)	$ (total)
Overhead Distribution	$ 79,000	$ (total)	$ (total)
Transformers	$ 2,000	$ (total)	$ (total)

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Meters	$ (total)	$ (total)	$ (total)
Total Capital Budget	$ 102,000	$ (sum)	$ (sum)

OEB	Description	Test Year	Test Year + 1	Test Year + 2
1805	Land	$ (total)	$ (total)	$ (total)
1820	Distribution Station Equip.	$ (total)	$ (total)	$ (total)
1830	O/H Poles, Towers, Fixtures	$ 67,000	$ (total)	$ (total)
1835	O/H Conductors, Devices	$12,000	$ (total)	$ (total)
1840	U/G Conduit	$11,000	$ (total)	$ (total)
1845	U/G Conductors, Devices	$10,000	$ (total)	$ (total)
1850	Line Transformers	$2,000	$ (total)	$ (total)
1860	Meters	$ (total)	$ (total)	$ (total)
1920	Computer Hardware	$ (total)	$ (total)	$ (total)
1925	Computer Software	$ (total)	$ (total)	$ (total)
1940	Tools, Shop, Garage Equip.	$ (total)	$ (total)	$ (total)
	Total Capital Expenditures	$102,000	$ (sum)	$ (sum)

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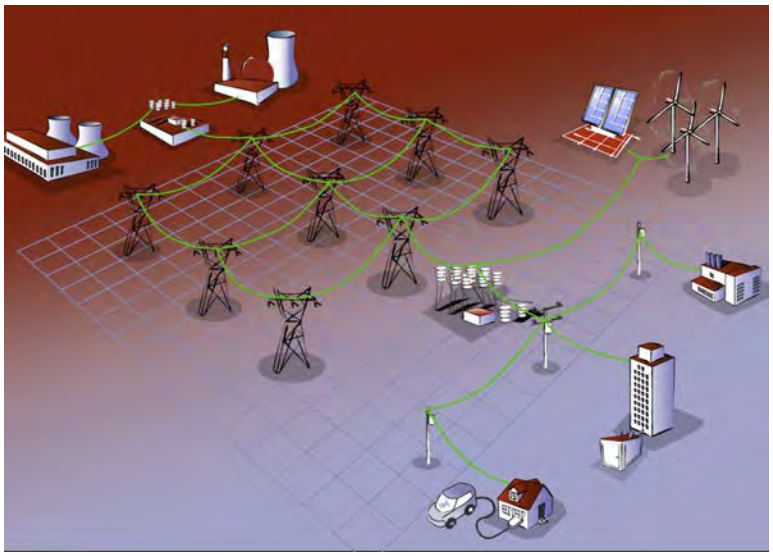
APPENDIX 8

Innisfil Hydro Distribution Systems Limited

Green Energy Act Plan (Basic Plan)



July 23, 2012

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1. Introduction

This document outlines the Green Energy Act Plan for Innisfil Hydro Distribution Systems Limited (IHDSL).

At this time IHDSL is filing the basic Green Energy Act (GEA) Plan, as directed by the OEB document EB-2009-0397 Distribution System Plans – Filing Under Deemed Conditions of License revised May 17, 2012. The basic GEA Plan provides information to the Board and interested stakeholders regarding the readiness of IHDSL's system to accommodate the connection of renewable generation and the expansion or reinforcement necessary to accommodate renewable generation. In addition this report provides information with respect to the general condition of the distribution system.

2. Current Assessment of Distribution System

2.1. Distribution System Overview:

Innisfil Hydro Distribution Systems Limited owns, operates, and maintains a distribution system currently serving approximately 15,000 customers within an area of about 300 square kilometers. The service territory encompasses all of the Town of Innisfil, which includes the communities of South Barrie, Stroud, Alcona, Lefroy, Churchhill, Cookstown, Gilford, Sandy Cove, and Big Bay Point. A majority of our customers are located in the above noted urban centers'. We also serve a smaller percentage of customers who are farmers.

IHDSL's industrial customer base is minimal in comparison to residential customers. We have had a significant growth in the area in the past 10 years and expect this trend to continue into the next decade. We predict our customer base to double in the next 15 years.

We currently operate our subtransmission system at 44 kV and our three-phase distribution system at 27,600 and 8,320 volts. We own, operate and maintain nine (9) distribution substations, jointly own, operate, and maintain four (4) private substations, and inspect and maintain seven (7) other customer owned substations.

The average age of our substations is 33 years; a majority of them were installed and commissioned in the 1970's. We own, operate, and maintain four (4) subtransmission feeders, 27 distribution feeders, approximately 750 km of both overhead and underground conductors, and 3,085 distribution transformers.

In the past six (6) years we have designed, installed, and commissioned one (1) distribution substation. We have systematically invested significant capital in upgrading our Distribution Automation (DA), and Supervisory Control and Data Acquisition (SCADA) systems, our IT infrastructure, deploying newer Reclosers and

Scada-Mate® switches, SCADA software for use by System Operators, and backend enterprise systems to support the need for better data management and system integration.

In 2011 we replaced all hydraulic reclosers at the Leonards Beach Distribution Station (DS) with the newer vacuum reclosers with microprocessor controls[1]. Our goal is to upgrade the remaining hydraulic reclosers in our distribution system in the near future with the newer vacuum type with advanced electronic controls, as part of our Smart Grid initiative. This initiative will help improve reliability by reducing outage duration while assisting our efforts to track and mitigate momentary interruptions.

We recently installed approximately 15,000 residential and commercial electric "smart" meters, completing our Advanced Metering Infrastructure (AMI) program and implementing TOU billing for all eligible customers by June 2011. We are currently developing internal processes to better utilize smart meter data to further improve our customer experience. Albeit, our AMI meters do not have true 2-way communication, thereby limiting our customers' ability to participate in the CDM Demand Response Programs pertaining to water heaters, pool pumps, peaksaver, etc. We are in the process of reviewing the cost implications for upgrading (1) AMI meters with 2-way communication capability, and (2) our current IT infrastructure (both capital and O&M) to accommodate the system requirements for the implementation of Demand Response programs.

We have worked with our neighbours, Hydro One and Power Stream, on our 15 year future growth plan to establish the possibility of building a 230 kV TS to better serve the growing demand for power.

We are committed to continuing our infrastructure renewal program **to improve customer participation** in reducing energy consumption**, improve system reliability** by reducing outages and outage duration**, improve operational efficiency** by deploying distribution automation and Smart SCADA technology, **improve security and safety** by reducing the vulnerability of the grid to unexpected hazards and promoting a safer system for both workers and the general public, and **promote environmental quality** by allowing customers to purchase cleaner, lower-carbon-emitting generation, and promote a more even deployment of renewable energy sources.

[1] G&W Viper Reclosers with SEL 351R controls

Table 1 - **Circuit length (in meters)**

System Voltage	44 kV	27.6 kV	8.32 kV	TOTAL
Overhead	125,900	98,700	382,800	607,400
Underground	700	66,100	74,400	141,200
<uncategorized>	300	3,600	1,700	5,600
Total	126,900	168,400	458,900	754,200

Table 2 - **Distribution Transformer Count**

System Voltage	44 kV	27.6 kV	8.32 kV	TOTAL
Overhead	0	444	1,649	2,093
Padmount	0	477	509	992
Total	0	921	2,158	3,085

2.2. Embedded Distribution System

Subtransmission: IHDSL is embedded into Hydro One Networks Inc.'s (HONI) subtransmission system. We currently own, operate, and maintain four (4) subtransmission feeders[2] from our boarder connection point, all of which have been identified by HONI to have available capacity to connect FIT or micro-FIT generators (as of July 17, 2012). A new subtransmission feeder[3] has been planned for 2017 to accommodate future load growth.

Distribution: Among our 27 distribution feeders 26 feeders still have available capacity to connect generators, while four other feeders are nearing their capacity for micro-FIT connection. As of this report date, 24 feeders have a total of 1.2 MW of solar generation already connected or slated to be connected.

2.3. Municipal Substations

IHDSL has nine (9) substations serving the community. The total design capacity is 58 MVA providing a margin of safety over the peak system load of 15%[4]. The subtransmission system (44 kV) allows for transfer of loads between stations as required.

[2] Alliston TS 9M1, 9M2, 9M4, and Barrie TS 13M3
[3] 9M6 from Alliston TS
[4] Based on a 70% load factor on our DS transformers

Table 3 - **Feeder Data:**

SUBSTATION	LOCATION	SIZE	OWNER	FEEDER #	Volt	Vintage
BIG BAY POINT DS	709 13th Line	5,000 KVA	Innisfil Hydro	F1 & F2	44/8.32 KV	1971
BOB DEUGO DS	2033 Commerce Park Drive	10,000 KVA	Innisfil Hydro	F1 & F2	44/27.6 kV	2006
BRIAN WILSON DS	1434 Innisfil Beach Road	20,000 KVA	Innisfil Hydro	F1, F2, F3 & F4	44/27.6 kV	1991 (T1) 1991 (T2)
CEDAR POINT DS	733 6th Line	5,000 KVA	Innisfil Hydro	F1 & F2	44/8.32 kV	1976
INNISFIL DS	2255 Highway #89	5,000 KVA	Innisfil Hydro	F1, F2 & F3	44/8.32 kV	1978
LEFROY DS	1495 Killarney Beach Road	5,000 KVA	Innisfil Hydro	F1, F2 & F3	44/8.32 kV	1970
LEONARDS BEACH DS	2895 25th Sideroad	5,000 KVA	Innisfil Hydro	F1 & F2	44/8.32 kV	1974
SANDY COVE DS	1104 Lockhart Road	5,000 KVA	Innisfil Hydro	F1 & F3	44/8.32 kV	1975
STROUD DS	2135 Lockhart Road	5,000 KVA	Innisfil Hydro	F1, F2 & F3	44/8.32 kV	1969
COOKSTOWN WEST DS	Victoria St. Cookstown, West of Cty.Rd. 27	7,000 KVA	Hydro One	F2 & F4	44/8.32 kV	--
THORNTON DS	Innisfil Beach Rd. East of Cty.Rd. 27	5,000 KVA	Hydro One	F1 & F2	44/8.32 kV	--

Note: All transformers are connected as Delta-Primary and Wye-Secondary.

2.4. Station Metering and Monitoring

We have installed and commissioned station monitoring equipment and systems on all nine (9) of our substations, while only three[5] (3) have smart SCADA equipment installed and functional, as noted in the table below. Our intent is to add remote sensing and switching capability with Smart Grid Self-healing properties to the remaining six (6) stations. *We currently do not monitor private substations.*

Table 4 – **Smart SCADA Status of IHDSL DS**

STATION	Station Monitoring Capability	Smart SCADA Status
BIG BAY POINT DS	YES	NEEDS UPGRADE
BOB DEUGO DS	YES	Fully Functional
BRIAN WILSON DS	YES	Fully Functional
CEDAR POINT DS	YES	NEEDS UPGRADE
INNISFIL DS	YES	NEEDS UPGRADE
LEFROY DS	YES	NEEDS UPGRADE
LEONARDS BEACH DS	YES	Fully Functional
SANDY COVE DS	YES	NEEDS UPGRADE
STROUD DS	YES	NEEDS UPGRADE

We are currently engaging with other public utilities to share costs.

- Communication infrastructure
  - We currently use an unlicensed frequency band for our SCADA system and have experienced significant signal interference. In an effort to improve signal quality we are working on replacing/upgrading all our communication equipment to use the dedicated utility frequency band that was recently released for LDC usage by Industry Canada. We are planning on completing this upgrade before the end of next year, which will require significant investment in capital and O&M.
  - As part of the SCADA upgrade we intend to replace the older vintage OPTOMUX protocol equipment with newer technology devices, while

[5] Namely Bob Deugo, Brian Wilson, and Leonards Beach DS

quality testing our existing DNP3 communication equipment to ensure long term reliable operation.

- This new technology gives us the capability to monitor and control DG units, which in turn allows us the opportunity to consider a higher number of DG connection requests.
- The installation of the new SCADA system will improve our ability to obtain real time voltage readings at various locations of our single and three phase distribution system, which in turn will enable us to better determine circuit response to load and other operating conditions. This will further assist us in the evaluation of DG connection requests.
- For the implementation of the above two projects it will be necessary for us to expand our technical support team by adding **ONE new position** in 2013. The added cost is reflected in Table 9.

2.5. Feeder Capacities to Connect Generation

At IHDSL we follow the guidelines stipulated by Hydro One in their document: Distributed Generation Technical Interconnection Requirements – Interconnections at Voltages 50kV and below; DT-10-015 Rev 2, June 2011. In this section Hydro One stipulates the acceptable generation limits for three-phase and single phase generators for DG facilities interconnected to HONI Distribution feeders. We use the same guidelines for our system. In addition, we use other industry recognized standards and procedures in determining connectability of DG's to our system; including IEEE 1547, which is the **"**Standard for Interconnecting Distributed Resources With Electric Power System", and calculations based on feeder specific load calculations. We have a design threshold to limit connected DG power to 50% of our calculated average minimum load of each feeder, which is determined to be 15% of the average maximum load on the respective feeder.

An internal tracking worksheet is used to log all interconnection points and their capacities. Using this log we are able to determine the total connected generation on each feeder, and decide if any additional generators can be connected.

The following table shows the connected or pending Distributed Generators (DG) on each feeder and the remaining capacities. Ratings are given in kilo-Watts.

Table 5 – IHDSL Feeder Capacity Status for DG Connectivity - Distribution

Distribution System

Distribution: Among our 27 distribution feeders 26 feeders still have available capacity to connect generators, while four feeders are nearing their capacity for micro-FIT connection.

Station	Feeder	Max DG Capacity	Connected or Pending	Remaining Capacity
Innisfil	F3	96	118	NONE
Innisfil	F1	122	40	82
Innisfil	F2	105	20	85
Big Bay Point	F1	124	3	121
Big Bay Point	F2	115	20	95
Bob Deugo	F1	47	10	37
Bob Deugo	F2	54	20	34
Brian Wilson	F1	91	71	20
Brian Wilson	F2	75	70	5
Brian Wilson	F3	168	82	86
Brian Wilson	F4	TBD	0	TBD
Cedar Point	F1	146	15	131
Cedar Point	F2	202	5	197
Cookstown-West	F2	82	13	69
Cookstown-West	F4	102	10	92
Leonards Beach	F1	104	7	97
Leonards Beach	F3	144	15	129
Lefroy	F1	152	10	142
Lefroy	F2	93	20	73
Lefroy	F3	60	20	40
Sandy Cove	F1	92	0	92
Sandy Cove	F3	69	0	69
Stroud	F1	86	25	61
Stroud	F2	16	10	6
Stroud	F3	132	44	88
Thornton	F1	67	50	17
Thornton	F2	33	30	3

Orange highlight: No more capacity for DG connection
Yellow highlight: Nearing capacity for DG connection

Subtransmission System

As noted earlier in this report IHDSL is embedded into Hydro One Networks Inc.'s (HONI) subtransmission system, and we currently own, operate, and maintain four (4) subtransmission feeders from our boarder connection point, all of which have been identified by HONI to have available capacity to connect FIT or micro-FIT generators as noted below.

Table 6 **- IHDSL Feeder Capacity Status for DG Connectivity - Subtransmission**

Feeder	TS	Voltage	Rating	Available DG Capacity
9M1	Alliston	44 kV	600 amps	30.0MW
9M2	Alliston	44 kV	600 amps	30.0MW
9M4	Alliston	44 kV	600 amps	29.80MW
13M3	Barrie	44 kV	600 amps	29.75MW

Note: Above capacity data was calculated on 17-July-2012 using Hydro One's Capacity Evaluation Tool. Please see Appendix section for screen shots of calculation.

2.6. Challenges related to our distribution system:

Currently we are facing capacity limitations on five (5) distribution feeders. One feeder has already reached its maximum capacity for DG connectivity while four (4) other feeders are nearing their maximum capacity. Over the next two to three years we are anticipating DG connection requests to amount to 2 - 3 MW in total. It is very likely that our aging infrastructure would need to be upgraded to accommodate the anticipated DG connection applications. However, an accurate estimate of the extent of system upgrades and associated costs are better determined after the specific feeders on which these DG units will be connected are identified. In the interim, as we continue to expand our in-house technical capabilities to conduct substation and feeder based studies, and implement communication and SCADA system upgrades, it is imperative that we have the opportunity to employ an **additional technician** starting in 2013 to adequately support these efforts.

One of the other challenges we face in our distribution system pertains to the sharing of the distribution infrastructure with other LDC's. We currently have four (4) feeders that are based out of two separate HONI owned stations, namely Thornton DS and Cookstown DS. Since two separate LDC's are operating out of the same substation it poses logistical problems. These arrangements pose unique challenges when working on micro-FIT and FIT projects.

Table 7 - **HONI owned DS with IHDSL feeders**

Station Name	Bus Name	Feeder Name	Voltage (kV)	Thermal Capacity (MW)	Upstream TS	Upstream TS Feeder
Cookstown West DS	Total	F1, F2*, F3, F4*	8.32	4.8	Everett TS	M6
Thornton DS	Total	F1*, F2*, F3	8.32	3.3	Alliston TS	M4

* Feeders owned by IHDSL

Long Term Load Transfer (LTLT) Customers

IHDSL supplies power to 95 Hydro One LTLT customers via three IHDSL's feeders[6]. These feeders supply power to the following LTLT customers: 61 metered

[6] Cookstown F4, and Thornton F1 and F2

customers, 33 flat rate customers, and 1 micro-FIT customer; these are HONI customers who are supplied power through our distribution infrastructure. We do not have any IHDSL customers who are fed off HONI distribution infrastructure.

Under this arrangement of shared ownership where the station is owned by HONI, the feeder is owned by IHDSL, and the distribution transformer and meter are owned by HONI, we have constant challenges in working through FIT and micro-FIT applications when approached by HONI customers. These customers come under the care of HONI yet for DG connectivity all infrastructure related calculations and upgrade works need to be done by IHDSL.

We have reviewed and analyzed various alternative solutions but all such options were deemed to be cost prohibitive.

We are cognisant of the June 30, 2014 deadline for eliminating LTLT arrangements which will help LDC's with dealing with distributed generation requests; however, logistical challenges for the remaining two years need to be addressed. As of the report date, IHDSL has 33 HONI owned transformers[7] on the distribution system.

2.7. Identification of Expenditures

As noted in table 5, several of our feeders do not have additional capacity for DG connectivity, and therefore, if we are to continue to offer our customers the opportunity to connect their renewable power generators to our grid we would need to implement a variety of infrastructure upgrade projects to accommodate their generators. As of this report date, a detailed engineering analysis and estimate is currently being developed.

As part of our infrastructure renewal plan we have proposed the following expenditure for the next five years:

Note: costs highlighted in green are in addition to IHDSL's forecasted Capital and OM&A budgets.

[7] 12 are located on the Cookstown F4 Feeder, 3 located on the Thornton F1 Feeder, and 18 located on the Thornton F2 Feeder.

Table 8 - **Substation & Distribution System Upgrade:**

Description	Budget $				
	2013	2014	2015	2016	2017
Recloser Automation, Replacement, & Line Recloser Maintenance (4 yr cycle)	$ 223,300[a]	$ 232,000[a]	$ 248,500[a]	$ 265,900[b]	$ 253,200[b]
44kV SCADA Controlled Load Interrupting Gang Switches	$ 160,100	$ 166,300	$ 178,200	$ 190,600	$ 203,000
27.6kV SCADA Controlled Load Interrupting Gang Switches	$ 253,200	$ 263,100	$ 281,700	$ 301,500	$ 321,000
Implementation of Automated Sectionalization and Restoration (ASR)[8]	$ 250,000	$ 250,000	$ 250,000	$ 250,000	$ 250,000
Fault Current Indicators	$ 38,400	$ 39,900	$ 42,700	$ 45,700	$ 48,700
Total	$1,175,000	$1,201,300	$1,251,100	$1,303,700	$1,325,900

[a:] Substation Recloser upgrade; [b] : Line Recloser Upgrade

Table 9 **- Investment in Personnel and Enterprise Architecture:**

Description	2012	2013	2014	2015	2016	2017
Smart Grid/Green Energy Engineer	75,000	100,000	103,000	106,100	109,270	112,550
- Support Tech.[c]	0	75,000	77,250	79,600	82,000	84,460
New SCADA System	200,000	250,000 [c]	0	0	0	0
Software Upkeep [c]	25,000	10,000	10,300	10,600	10,900	11,500
Radio Hardware Installation & Commissioning [c]	0	200,000	0	0	0	0

[C] Not included in the current 5 year plan

[8] Not included in the current 5 year plan. The implementation of the ASR scheme will give us the option to automatically sectionalize faulted segments of a feeder and restore power to as many customers as possible through the intelligent and strategic switching of circuit ties.

GEA Budget

Costs to support the Substation & Distribution System Upgrade, Investment in Enterprise Architecture and personnel to support the technology and implementation is broken down by category and year in the following table,

	2013 ($000)	2014 ($000)	2015 ($000)	2016 ($000)	2017 ($000)	Total ($000)
Capital	710	260	261	261	262	1754
OM&A	75	77	80	82	84	398
Total	785	337	341	343	346	2152

Further details of the GEA Budget, strategy and proposed riders will be addressed within IHDSL's COS Application EB-2012-0139.

2.8. Unique Challenges

We have seen substantial interest from farmers in our service territory for both microFIT and FIT solar projects; however, with the visibility of the generators there has been a steady transition of residential roof mount solar projects. Given the older infrastructure on parts of our service territory we see a need for upgrading our infrastructure over the next few years.

3. Planned Development of the Distribution Systems to Accommodate Generation Connections

3.1 Existing and Pending Renewable Generation Projects:

Since the rollout of the MicroFIT and FIT programs, IHDSL has received a large number of requests for solar panel installations on its grid. To date we have approximately 135 FiT/MicroFiT projects that have either been approved or being evaluated, while several other requests are being put on hold due to capacity. Although received projects slowed down in late 2011 due to the 2 Year FIT Review, IHDSL is again experiencing an increase in DG connectivity requests. IHDSL fully expects the requests to maintain in the foreseeable future. Therefore, need to plan infrastructure upgrade projects including substation and distribution automation, to benefit DG connections, and accommodate additional generation.

MicroFIT Summary

Installed Projects by Year

YEAR	2010	2011	2012	2013	2014	2015	2016
Forecast	5	15	20	25	30	30	30
Actual	10	29	10 *				

*as of July 23, 2012

Breakdown of MicroFIT Applications (as of July 23, 2012)

Total Connected	49
Pending Connection	32
Pending LDC OTC	15
Application Terminated	27
Contract Transferred	8
Total Applications	131
Total Capacity	1173.52 kW

FIT Summary

Installed Projects by Year

YEAR	2010	2011	2012	2013	2014	2015	2016
Forecast	1	2	3	3	3	3	3
Actual	0	1	0*				

*as of July 23, 2012

Breakdown of FIT Applications (as of July 23, 2012)

Total Connected	1
In CIA Process	1
Pending CIA Process	2
Total Applications	4
Total Capacity	990 kW

3.2 Infrastructure Projects and Activities to Accommodate Renewable Generation

Our priority would be to upgrade feeders that have reached maximum capacity for DG connectivity. At the top of the list is the upgrading of the backbone of our Innisfil F3 feeder, on which we have a backlog of DG applications, and that is long past its depreciation. We have observed widespread deterioration of the assets of this feeder and have deemed it necessary to completely rebuild about 5 km of infrastructure at an approximate cost of $600k-$700k, subject to feeder load conditions.

In addition, the upgrade projects that are part of our Smart Grid initiatives are expected to indirectly benefit renewable generation.

3.3 Costs to be Recovered

For the above noted project we anticipate our material to labor cost ratio to be approximately 40/60.

Additional cost recovery schedules will be provided upon request.

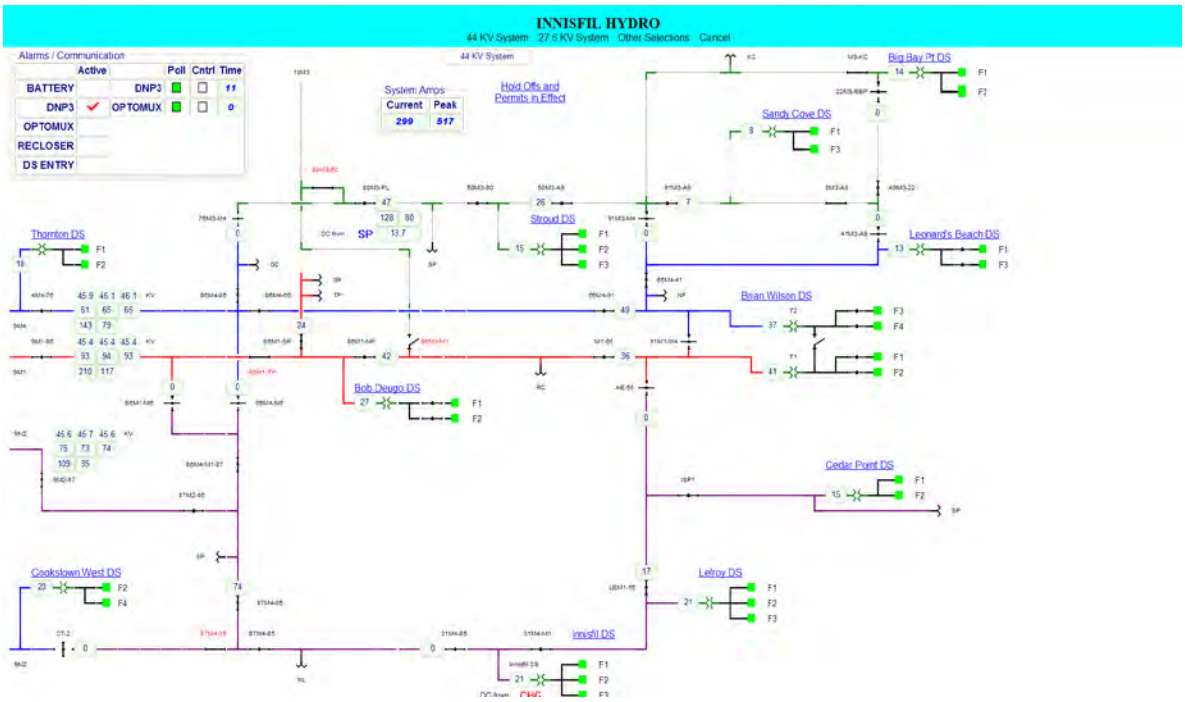
4. Smart Grid Development

One of the major initiatives IHDSL had worked on under the Smart Grid umbrella is the AMI project. As part of this project we installed and commissioned approximately 15,000 meters. In addition we have invested time and resources for the upkeep of our SCADA system, replacing, upgrading, and/or maintaining substation Remote Terminal Units (RTU's), SCADA switches, and Reclosers.

We are continuing to pursue projects to further modernize and automate our infrastructure, while looking for ways to provide our customers more choices to conserve energy.

Our grid modernization plan includes:

- Replacing our old SCADA system with modern state of the art system. Our current 8,320 volt distribution system is not tied into our current SCADA system, while our 27.6 kV system has limited line visibility.
    - The new SCADA system will help improve visibility on both these systems and will help with quicker outage restoration, improving our SAIDI and CAIDI metrics.
    - Our SCADA system, as currently configured, is remotely operable through control terminals in our operation centres as well as through secure mobile devices. The new SCADA system we are proposing to install will also be configured with remote accessibility, allowing greater functionality.



- Introducing enterprise-wide engineering, accounting, work management, and customer information systems that seamlessly integrate to provide improved efficiency, and better business intelligence that would lead to better business decisions for our customers and us
- Replacing/upgrading our reclosers and switches for the implementation of "Distribution Automation".
- Installing advanced Fault Current Indicators with communication capability will reduce the time taken to locate our faults and help reduce outage restoration times and overall reliability.

Some of the Benefits of Distributed Generation:

- Power quality and reliability- For sensitive equipment (computer equipment, manufacturing process equipment) or in the event where a power outage could seriously impact a business, DG can be used to improve power quality and reliability.

- Security - A DG system can provide added security by maintaining power to critical operating areas which would otherwise be affected by utility power outages.

- Environment - Many DG installations reduce total emissions levels by using energy resources more efficiently, replacing heating and water heating fossil fuel combustion emissions and in some cases displacing more damaging central plant emissions.

- Other – DG's further help with avoiding future expansions of transmission and distribution networks in their respective areas.

How Investment in Smart Grid Technology may help Distributed Generation Initiatives:

- The implementation of Substation and Distribution Automation is expected to reduce the number of sustained outages and thereby decreasing the downtime of DG units that would have otherwise been dropped from the grid.

- The ability to track momentary outages by installing advanced microprocessor controlled automatic interrupting devices will provide intelligent data on momentary outages that would help LDC's implement proactive solutions to eliminate sustained outages.

- Our new communication infrastructure will enable real time monitoring of our subtransmission and distribution system, further helping operator assisted restoration efforts, and thereby reducing downtime.

- The installation of smart meters will enable us to harvest accurate load data which in turn will help us optimize DG connection capacity on our feeders.

5. Summary

The GEA Plan has been prepared to illustrate the ability to accommodate renewable generation. Through the plan the existing capacity has been outlined as well as requirements for future investments.

In order for IHDSL to continue to accommodate DG connection requests, given our current system limitations, we would need to follow through with the various infrastructure improvement projects as outlined above.

Should additional supporting documentation be required IHDSL will be glad to provide such as required.

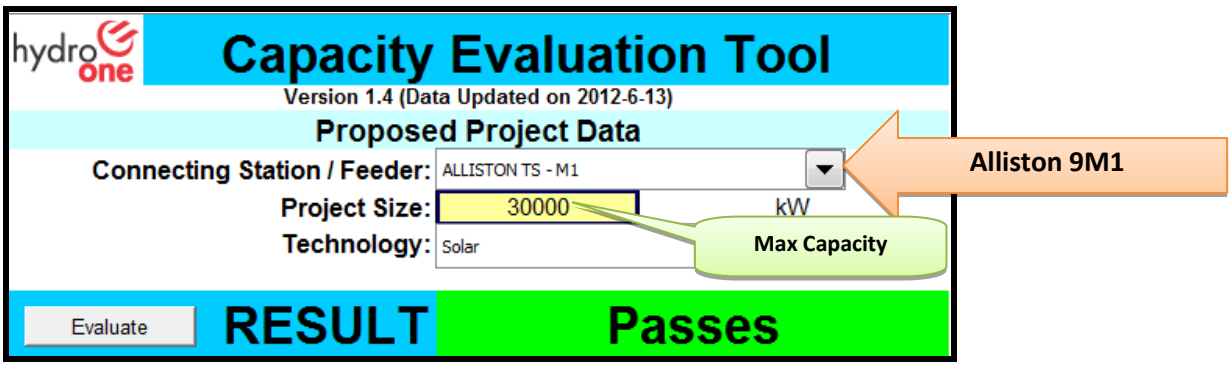
END OF REPORT

Appendix

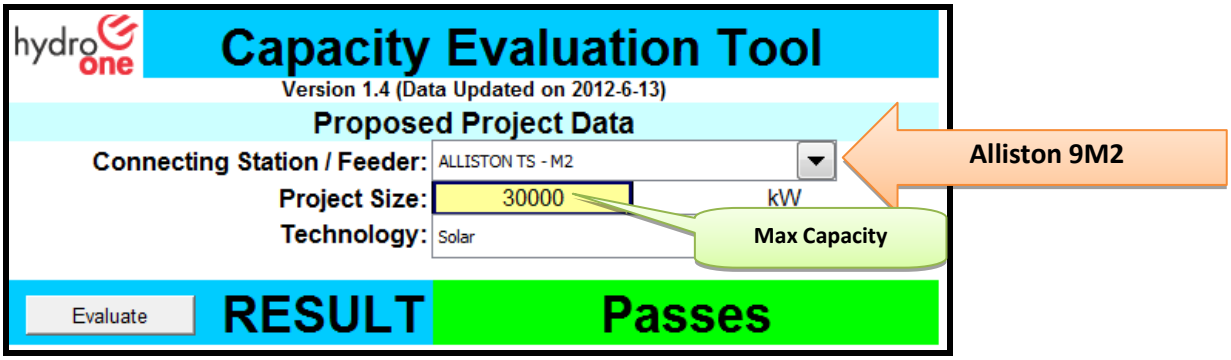
Service Territory

Barrie
Innisfil
Essa
Churchill
Cook's Bay
Gilford
Bradford West Gwillimbury
Holland Landing Airpark
Regional Road 40
Regional Road 20
Sunnidale Rd
Tiffin St
Ardagh Rd
Mapleton Ave
Sideroad 25
McKay Rd
Victoria St
Innisfil Beach Rd
Yonge St
10 Sideroad
20 Sideroad
25th Side Rd
Mapleview Dr
10 Line
4 Line
Shore Acres Dr
County Road 89
Sideroad 5
Sideroad 20
12th Line
11 Line
9th Line
8 Line
7th Line
5 Line
Sideroad 10
Sideroad 15
Bradford St
King St S
Queensville Side Rd
Church St
Leslie St
INNISFIL HYDRO
DISTRIBUTION SYSTEMS LIMITED
SERVICE TERRITORY MAP
SCALE:
2 km
2 mi

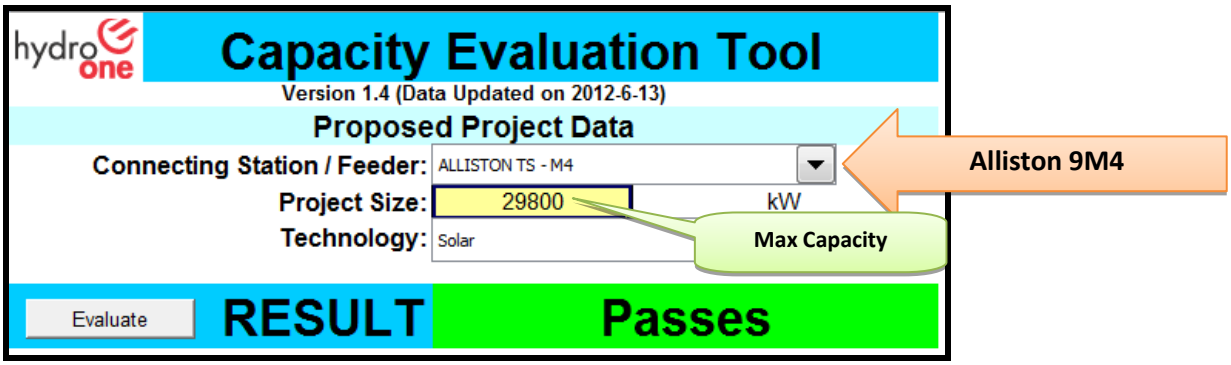
DG connectivity capacity at TS



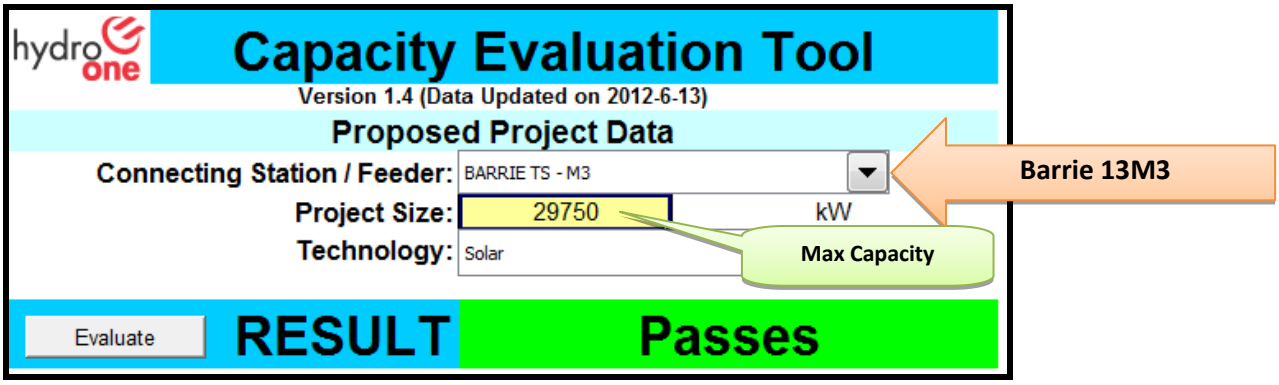
Above test FAILED at 31MW



Above test FAILED at 31MW



Above test FAIELD at 29.9MW



Above test FAILED at 29.8MW

Note: These scenarios were tested on 17-July-2012 using Hydro One's Capacity Evaluation Tool.

OPA Letter of Comment:

Innisfil Hydro Distribution Systems Limited

Basic Green Energy Act Plan

August 20, 2012

ONTARIO POWER AUTHORITY

Introduction

On March 25, 2010, The Ontario Energy Board ("the OEB") issued its Filing Requirements for Distribution System Plans. As a condition of Licence, Ontario Distributors are required to file a Green Energy Act Plan as part of their cost of service application.

The Filing Requirements distinguish between Basic and Detailed Green Energy Act Plans ("Plan" or "GEA Plan") and outline the specific information and level of detail which must be provided for each type of Plan. Recognizing the importance of coordinated planning in achieving the goals of the *Green Energy and Green Economy Act, 2009* (the "GEA"), distributors must consult with embedded and host distributors, upstream transmitters and the OPA in preparing their Plans. For both Basic and Detailed Plans, distributors are required to submit as part of the Plan, a letter of comment from the OPA.

The OPA will review distributors' Basic Plans to ensure consistency with regard to FIT and microFIT applications received, as well as with integrated Plans for the region or the system as a whole.

Innisfil Hydro Distribution Systems Limited - Basic Green Energy Act Plan

The OPA has reviewed the Basic GEA Plan from Innisfil Hydro Distribution Systems Limited dated July 23rd, 2012, and has provided its comments below.

OPA FIT/microFIT Applications Received

Innisfil Hydro's GEA Plan indicates they have received applications for 131 microFIT and 4 Capacity Allocation Except ("CAE") projects within their service territory. Of these, 49 microFIT and 1 CAE projects have been connected. No Capacity Allocation Required (CAR) applications have been received. This information is shown in section 3.1 *Existing and Pending Renewable Generation Projects* of the Plan.

According to OPA's information, as of August 8th, 2012, 130 microFIT, and 4 Capacity Allocation Exempt ("CAE") applications have been received in Innisfil Hydro's service territory, representing 1.16 MW and 0.99 MW of capacity, respectively. Of these, 53 microFIT and 1 CAE projects are currently connected.

Upstream Transmission Constraints

According to the information provided in Innisfil Hydro's GEA Plan, Innisfil Hydro's distribution system is supplied from feeders originating from Alliston TS and Barrie TS. The OPA confirms that there are no currently known upstream transmission constraints at Alliston, Barrie TS, or at other nearby transmission supply points.

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Further details on capacity at the above mentioned stations may be found in the updated Transmission Availability Table for Small FIT 2012 available on the OPA's FIT website as follows: http://fit.powerauthority.on.ca/sites/default/files/TAT%20Table%20Final%20-%20April%205%20for%20posting.pdf

Economic Connection Test

The OPA received a directive dated April 5, 2012 from the Minister of Energy with respect to the Feed-in Tariff Program Review. The directive states that "[g]iven the transmission projects planned through the Long Term Energy Plan and changes to the FIT Program, the OPA shall not run the Economic Connection Test ". A link to the full directive is provided on the OPA's website: http://www.powerauthority.on.ca/sites/default/files/page/FIT-ReviewApril-2012.pdf

Opportunities for Integrated Solutions

There are no known corresponding expansions among neighbouring LDCs that could be addressed through integrated transmission solutions at this time.

Conclusion

The OPA finds that Innisfil Hydro's Basic GEA Plan is reasonably consistent with the OPA's information regarding renewable energy generation applications to date.

The OPA appreciates the opportunity to comment on Innisfil Hydro's Basic GEA Plan.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 1-800-797-9604 Toll Free
info@powerauthority.on.ca www.powerauthority.on.ca

EXHIBIT A

Innisfil Hydro Distribution Systems Ltd — APPENDIX 9

Capital Expenditure Request

Date	Jan-13
Project Title	Retail Meters
Job Type	Meters
Request number	IHDSL 2013 DB 001

Description and Purpose	Legislative Requirement
Purchase single and three phase meters for new services as required by Measurement Canada	

Economic Justification

Tax depreciation declining balance (%)	4%	Payback period (in years)	N/A
Book depreciation life (in years)	25	Internal rate of return (IRR%)	-39.3%
Estimated delivery/start date		Cumulative Economic Value Added	($76,296)
Estimated start-up period (in months)			
Anticipated post audit date			

Cost Summary

Capital expenditure	$	115,900
Related expenses	$	-
Additional working capital requirements		
Total funds required	$	115,900

Quote no. 1 (selected)	
Quote no. 2	
Quote no. 3	

Included in current Profit Plan / Budget

Yes / No	
Amount in Plan/ Budget if Yes	
Reason if No	

Approvals

		Date
Prepared by		
Project Leader		
Director		
CFO/Treasurer	Laurie Ann Cooledge	
President and CEO	George Shaparew	
Board of Directors approval		

EXHIBIT A

Innisfil Hydro Distribution Systems Ltd

Capital Expenditure Request

Date	**Feb-12**
Project Title	**Station Recloser Automation,Repl.& Ln.Recl.Maint. 4 yr. Cycle**
Job Type	**Reliability & System**
Request number	**2013 DO 001**

Description and Purpose	**Reliability**
Refurbishing existing hydraulic line and DS reclosers. This is a four (4) year cycle. Replacing existing reclosers with new vacuum recloser at Cedar Point DS & Lefroy DS (two (2) sets at each DS). Also, implement SCADA automation and control for new vacuum reclosers. This will improve substation automation and increase reliability of the system.	

Economic Justification

Tax depreciation declining balance (%)	**4%**	**Payback period (in years)**	**N/A**
Book depreciation life (in years)	**25**	**Internal rate of return (IRR%)**	**#NUM!**
Estimated delivery/start date		**Cumulative Economic Value Added**	**($146,996)**
Estimated start-up period (in months)			
Anticipated post audit date			

Cost Summary

Capital expenditure	**$**	**223,300**
Related expenses	**$**	**-**
Additional working capital requirements		
Total funds required	**$**	**223,300**

Quote no. 1 (selected)	
Quote no. 2	
Quote no. 3	

Included in current Profit Plan / Budget

Yes / No	
Amount in Plan/ Budget if Yes	
Reason if No	

Approvals

		Date
Prepared by		
Project Leader		
Director		
CFO/Treasurer	**Laurie Ann Cooledge**	
President and CEO	**George Shaparew**	
Board of Directors approval		

EXHIBIT A

Innisfil Hydro Distribution Systems Ltd

Capital Expenditure Request

Date	**Feb-12**
Project Title	**44 kV Alduti Ruptor**
Job Type	**Reliability & System**
Request number	**2013 DO 002**

Description and Purpose	**Reliability**
Two (2) switches in total. Each of these switches shall replace an aging and obsolete current airbreak or MSO location. These switches are designed utilizing SCADA technology to faster isolate faulted locations in the 44kV subtransmission system.	

Economic Justification

Tax depreciation declining balance (%)	**4%**	**Payback period (in years)**	**N/A**
Book depreciation life (in years)	**25**	**Internal rate of return (IRR%)**	**#NUM!**
Estimated delivery/start date		**Cumulative Economic Value Added**	**($105,392)**
Estimated start-up period (in months)			
Anticipated post audit date			

Cost Summary

Capital expenditure	**$**	**160,100**
Related expenses	**$**	**-**
Additional working capital requirements		
Total funds required	**$**	**160,100**

Quote no. 1 (selected)		
Quote no. 2		
Quote no. 3		

Included in current Profit Plan / Budget

Yes / No		
Amount in Plan/ Budget if Yes		
Reason if No		

Approvals

		Date
Prepared by		
Project Leader		
Director		
CFO/Treasurer	**Laurie Ann Cooledge**	
President and CEO	**George Shaparew**	
Board of Directors approval		

EXHIBIT A

Innisfil Hydro Distribution Systems Ltd

Capital Expenditure Request

Date	**Feb-12**
Project Title	**27.6 kV Mechanized SCADA Controlled Load Interruptors**
Job Type	**Reliability**
Request number	**2013 DO 003**

Description and Purpose — Reliability

Install 27.6 kV vacuum line reclosers, conect with SCADA and implement distribution system automation. Total of three (3) sets to be installed at strategic locations. These reclosers will be SCADA operated and distribution automation equipped. This is a step forward towards Smart Grid providing automatic isolation of faulted line sections & automatic power restoration to healthy line section. Provide enhanced reliability & safety.

Economic Justification

Tax depreciation declining balance (%)	**4%**	**Payback period (in years)**	**N/A**
Book depreciation life (in years)	**25**	**Internal rate of return (IRR%)**	**-39.3%**
Estimated delivery/start date		**Cumulative Economic Value Added**	**($166,663)**
Estimated start-up period (in months)			
Anticipated post audit date			

Cost Summary

Capital expenditure	**$**	**253,179**
Related expenses	**$**	**-**
Additional working capital requirements		
Total funds required	**$**	**253,179**

Quote no. 1 (selected)	
Quote no. 2	
Quote no. 3	

Included in current Profit Plan / Budget

Yes / No	
Amount in Plan/ Budget if Yes	
Reason if No	

Approvals

		Date
Prepared by		
Project Leader		
Director		
CFO/Treasurer	**Laurie Ann Cooledge**	
President and CEO	**George Shaparew**	
Board of Directors approval		

EXHIBIT A

Innisfil Hydro Distribution Systems Ltd

Capital Expenditure Request

Date	**Feb-12**
Project Title	**Infrastructure Btrmnts.**
Job Type	**Customer Demand**
Request number	**2013 DO 004**

Description and Purpose — **Health & Safety / Reliability**

Replace suspect porcelain dead end bells within distribution system. Secondary buss replacement. Replace rotting cross arms. Replace defective in-line 44kV, 27.6 kV and 8.32 kV switches.

Economic Justification

Tax depreciation declining balance (%)	**4%**	**Payback period (in years)**	**N/A**
Book depreciation life (in years)	**25**	**Internal rate of return (IRR%)**	**#NUM!**
Estimated delivery/start date		**Cumulative Economic Value Added**	**($138,833)**
Estimated start-up period (in months)			
Anticipated post audit date			

Cost Summary

Capital expenditure	**$**	**210,900**
Related expenses	**$**	**-**
Additional working capital requirements		
Total funds required	**$**	**210,900**

Quote no. 1 (selected)	
Quote no. 2	
Quote no. 3	

Included in current Profit Plan / Budget

Yes / No	
Amount in Plan/ Budget if Yes	
Reason if No	

Approvals

		Date
Prepared by		
Project Leader		
Director		
CFO/Treasurer	**Laurie Ann Cooledge**	
President and CEO	**George Shaparew**	
Board of Directors approval		

EXHIBIT A

Innisfil Hydro Distribution Systems Ltd

Capital Expenditure Request

Date	**Feb-12**
Project Title	**U/G Padmnt.Tx Replacements & Painting**
Job Type	**Infrastructure Replacement**
Request number	**2013 DO 005**

Description and Purpose — Reliability

Inspections have detected that certain padmount transformers are starting to rust. Some transformers need normal repair and painting, while some transformers are beyond normal repair and need replacement. To ensure deteriorating padmount transformers do not pose a safety or environmental risk, a program to identify and replace these transformers is required.

Economic Justification

Tax depreciation declining balance (%)	**4%**	**Payback period (in years)**	**N/A**
Book depreciation life (in years)	**25**	**Internal rate of return (IRR%)**	**#NUM!**
Estimated delivery/start date		**Cumulative Economic Value Added**	**($52,464)**
Estimated start-up period (in months)			
Anticipated post audit date			

Cost Summary

Capital expenditure	**$**	**79,700**
Related expenses	**$**	**-**
Additional working capital requirements		
Total funds required	**$**	**79,700**

Quote no. 1 (selected)	
Quote no. 2	
Quote no. 3	

Included in current Profit Plan / Budget

Yes / No	
Amount in Plan/ Budget if Yes	
Reason if No	

Approvals

		Date
Prepared by		
Project Leader		
Director		
CFO/Treasurer	**Laurie Ann Cooledge**	
President and CEO	**George Shaparew**	
Board of Directors approval		

EXHIBIT A

Innisfil Hydro Distribution Systems Ltd

Capital Expenditure Request

Date	**Feb-12**
Project Title	**Substandard TX Rehabs**
Job Type	**Infrastructure Replacement**
Request number	**2013 DO 006**

Description and Purpose	**Health & Safety**
Sub-standard transformer installations not to ESA Standards, where the transformer is installed below the secondary buss. This method of framing was used in earlier years of construction to conserve on pole height. These installations now pose a clearance, and subsequent safety risk to staff and the public, while working on or in the vicinity of these installations.	

Economic Justification

Tax depreciation declining balance (%)	**4%**	**Payback period (in years)**	**N/A**
Book depreciation life (in years)	**25**	**Internal rate of return (IRR%)**	**-39.3%**
Estimated delivery/start date		**Cumulative Economic Value Added**	**($120,268)**
Estimated start-up period (in months)			
Anticipated post audit date			

Cost Summary

Capital expenditure	**$**	**182,700**
Related expenses	**$**	**-**
Additional working capital requirements		
Total funds required	**$**	**182,700**

Quote no. 1 (selected)		
Quote no. 2		
Quote no. 3		

Included in current Profit Plan / Budget

Yes / No		
Amount in Plan/ Budget if Yes		
Reason if No		

Approvals

		Date
Prepared by		
Project Leader		
Director		
CFO/Treasurer	**Laurie Ann Cooledge**	
President and CEO	**George Shaparew**	
Board of Directors approval		

EXHIBIT A

Innisfil Hydro Distribution Systems Ltd

Capital Expenditure Request

Date	**Feb-12**
Project Title	**Pole Replacement**
Job Type	**Infrastructure Replacement**
Request number	**2013 DO 007**

Description and Purpose	**Health & Safety / Reliability**
Approximately 1/8th of Innisfil Hydro's poles will be tested throught it's testing program. With an anticipated 4% failure rate, an estimated sixty (70) poles will be replaced. Twenty (20) poles with live three (3) phase - no transformer. Twenty (20) poles with live one (1) phase - no trans Fifteen (15) poles with live three (3) phase with transformer. Fifteen (15) poles with live one (1) phase with trans	

Economic Justification

Tax depreciation declining balance (%)	**4%**	**Payback period (in years)**	**N/A**
Book depreciation life (in years)	**25**	**Internal rate of return (IRR%)**	**-39.3%**
Estimated delivery/start date		**Cumulative Economic Value Added**	**($257,581)**
Estimated start-up period (in months)			
Anticipated post audit date			

Cost Summary

Capital expenditure	**$**	**391,289**
Related expenses	**$**	**-**
Additional working capital requirements		
Total funds required	**$**	**391,289**

Quote no. 1 (selected)		
Quote no. 2		
Quote no. 3		

Included in current Profit Plan / Budget

Yes / No		
Amount in Plan/ Budget if Yes		
Reason if No		

Approvals

		Date
Prepared by		
Project Leader		
Director		
CFO/Treasurer	**Laurie Ann Cooledge**	
President and CEO	**George Shaparew**	
Board of Directors approval		

EXHIBIT A

Innisfil Hydro Distribution Systems Ltd

Capital Expenditure Request

Date	**Feb-12**
Project Title	**27kV Extension 20th S.R.,BBPt to 13th Ln**
Job Type	**Reliability**
Request number	**2013 DO 008**

Description and Purpose	**Growth**
27.6 kV line extenstion to service Big Bay Point Development. 27.6kV tie between future Big Bay Point station and Brian Wilson for back-up. Without this project, the station could not be shut down for maintenance and a substation failure would result in a localized blackout lasting days.	

Economic Justification

Tax depreciation declining balance (%)	**4%**	**Payback period (in years)**	**N/A**
Book depreciation life (in years)	**25**	**Internal rate of return (IRR%)**	**#NUM!**
Estimated delivery/start date		**Cumulative Economic Value Added**	**($476,791)**
Estimated start-up period (in months)			
Anticipated post audit date			

Cost Summary

Capital expenditure	**$ 724,294**	
Related expenses	**$ -**	
Additional working capital requirements		
Total funds required	**$ 724,294**	

Quote no. 1 (selected)		
Quote no. 2		
Quote no. 3		

Included in current Profit Plan / Budget

Yes / No		
Amount in Plan/ Budget if Yes		
Reason if No		

Approvals

		Date
Prepared by		
Project Leader		
Director		
CFO/Treasurer	**Laurie Ann Cooledge**	
President and CEO	**George Shaparew**	
Board of Directors approval		

EXHIBIT A

Innisfil Hydro Distribution Systems Ltd

Capital Expenditure Request

Date	**Feb-12**
Project Title	**Big Bay Point F3 for BBPT Development**
Job Type	**Customer Demand**
Request number	**2013 DO 009**

Description and Purpose	**Growth**
To prepare for the first phase of the Big Bay Point Development, we need to rebuild existing three (3) phase 8.3kV line east of Big Bay Point DS along the 13th Line to the south entrance of the development to accommodate new three (3) phase 27.6kV circuit feeding Big Bay Point Development.	

Economic Justification

Tax depreciation declining balance (%)	**4%**	**Payback period (in years)**	**N/A**
Book depreciation life (in years)	**25**	**Internal rate of return (IRR%)**	**#NUM!**
Estimated delivery/start date		**Cumulative Economic Value Added**	**($72,900)**
Estimated start-up period (in months)			
Anticipated post audit date			

Cost Summary

Capital expenditure	**$**	**110,743**
Related expenses	**$**	**-**
Additional working capital requirements		
Total funds required	**$**	**110,743**

Quote no. 1 (selected)		
Quote no. 2		
Quote no. 3		

Included in current Profit Plan / Budget

Yes / No		
Amount in Plan/ Budget if Yes		
Reason if No		

Approvals

		Date
Prepared by		
Project Leader		
Director		
CFO/Treasurer	**Laurie Ann Cooledge**	
President and CEO	**George Shaparew**	
Board of Directors approval		

EXHIBIT A

Innisfil Hydro Distribution Systems Ltd

Capital Expenditure Request

Date	**Feb-12**
Project Title	**Utility Relocates**
Job Type	**Customer Demand**
Request number	**2013 DO 010**

Description and Purpose	**Legislative**
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 and the Operating Corporation (Innisfil Hydro), the Road Authority 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	

Economic Justification

Tax depreciation declining balance (%)	**4%**	**Payback period (in years)**	**N/A**
Book depreciation life (in years)	**25**	**Internal rate of return (IRR%)**	**-39.3%**
Estimated delivery/start date		**Cumulative Economic Value Added**	**($44,812)**
Estimated start-up period (in months)			
Anticipated post audit date			

Cost Summary

Capital expenditure	**$**	**68,074**
Related expenses	**$**	**-**
Additional working capital requirements		
Total funds required	**$**	**68,074**

Quote no. 1 (selected)		
Quote no. 2		
Quote no. 3		

Included in current Profit Plan / Budget

Yes / No		
Amount in Plan/ Budget if Yes		
Reason if No		

Approvals

		Date
Prepared by		
Project Leader		
Director		
CFO/Treasurer	**Laurie Ann Cooledge**	
President and CEO	**George Shaparew**	
Board of Directors approval		

Exhibit	Tab	Schedule	Appendix	Contents
2 – Rate Base				
	1			**Overview**
		1		IHDSL Introduction to Rate Base
		2	1	Property Appraisal Executive Summary – 2061 & 2073 Commerce Park Drive
			2	Designated Substances & Hazardous Materials Survey
			3	Property Appraisal Executive Summary – 2147 Innisfil Beach Road
			4	Floor Plan – 1st Floor
			5	Floor Plan – 2nd Floor
			6	Site Plan
				Overview
		3		Variance Analysis of Rate Base
	2			**Gross Assets – Property, Plant and Equipment Accumulated Amortization**
		1		Continuity Statements
		2		Gross Assets Table
		3		Variance Analysis on Gross Assets
		4		Accumulated Amortization Table
		5		Variance Analysis on Accumulated Amortization
	3			**Capital Budget**
		1		Introduction
		2		Asset Management Plan Summary
		3		Capitalization Policy
		4		Service Quality & Reliability Performance

Exhibit	Tab	Schedule	Appendix	Contents
2 – Rate Base (Cont'd)	**4**			**Allowance for Working Capital**
		1		Overview and Calculation by Account
	5			**Conversion to MIFRS**
		1		Impact on Fixed Assets
		2		Impact on Capital Budgets
		3		PP&E Deferral Account and Request for Disposition
		4		Impact on Rate Base
	6			Green Energy Plan
			A	Asset Management Plan
			B	Cost of Power Calculation
			C	Green Energy Plan
			D	OPA Letter of Comment
			E	GEA Funding Adder Justification
			F	GEA Funding Adder

IHDSL INTRODUCTION TO RATE BASE:

As referenced in the Executive Summary in Exhibit 1, IHDSL is reflecting significant capital expenditures for the 2012 Test Year and the 2013 Bridge Year. The expenditures of $2,000,000 in 2012 and $5,000,000 in 2013 are directly related to the requirement of a new building/facility for IHDSL.

Key components for the requirements of a new building/facility are as follows;

- Long term growth forecasts from 14,500 customers in 2009 to 38,000 customers in 2031.
- 5 non-contiguous buildings, all with accessibility issues for customers and IHDSL staff. IHDSL will not be in a position to meet future accessibility requirements for our customers.
- Health and Safety – 10 reported slip/trip/fall incidents including 1 customer since 2009.
- Currently not meeting Government Office Space Standards of 250 sq' per person by 17% with existing staff compliment.

Following are some pictures of IHDSL's current site reflecting some of the afore-mentioned issues.

In addition to this significant capital spend IHDSL has balanced the requirement for a new building facility with the demands of maintaining and improving our distribution infrastructure to meet customer demand without significant impact to the end customer. The existing capital budget is being prudently managed and is not increasing except for the one-time requirement for a new office/operations facility.

The following table demonstrates the % capital spend by capital category for IHDSL since 2007.

IHDSL Project Costs by Category (%)									
Category	2007	2008	2009	2010	2011	2012	2012 excl Facilites	2013	2013 excl Facilities
Infrastructure Replacement	25%	10%	17%	14%	43%	13%	18%	8%	18%
Reliability	10%	21%	42%	3%	7%	7%	35%	15%	35%
Capacity	2%		15%						
Security		17%	5%		1%				
Meter	2%	3%	-43%	-10%		3%	3%	1%	3%
Customer Demand	40%	28%	52%	69%	33%	33%	26%	11%	26%
Substation	1%			1%					
Facilities	3%	5%				32%		56%	
Hardware and Software	13%	6%	3%	1%	2%	9%	9%	4%	9%
Transportation	2%	1%		13%	8%		2%	1%	2%
Regulatory		9%							
Communication	2%								
Tools & Equipment	1%	1%		6%	2%				
Miscellaneous General Plant			9%	4%	5%	4%	7%	3%	7%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%

IHDSL Space Needs Summary

When IHDSL purchased the distribution assets from Ontario Hydro within the Town of Innisfil in 1993, the entire company had to be built from the ground up including staffing, offices, warehousing, billing etc. At the same time, there were six rate reductions over the next seven years.

A number of office locations were originally investigated including an old chicken barn, but the one that was chosen was a site with three Pan-abode model buildings. Customer Service in one building, Engineering/Finance in another and the Warehouse in the garage. The site was originally leased in 1993 and then was purchased in 2000. While many LDCs gave their administrative properties to their shareholders at the time of incorporation, IHDSL did not. Two surplus public school portables were added in 2008 for smart metering space requirements.

A new office building was budgeted for in 2004 but was deferred until a comprehensive long range plan was in place. In 2009, IHDSL's customer base was 14,500 which was expected to grow to 38,000 customers by year 2031. Staff growth requirements from ~30 in year 2009 to

~75 in year 2031 could not be accommodated in the existing facility. In 2009, an investigation was commissioned to McKnight Sharron Laurin Architects which undertook an investigation of five options:

1. Purchase a Greenfield site and build new facilities;
2. Purchase a site with an existing 15,000 s q' building, modify to suit and build an Operations Centre;
3. Build a new building on the existing site;
4. Modify the existing buildings on the existing site;
5. Utilize the vacant 12,000 sq' Old Town Hall, modify and build an Operations Centre.

The most cost beneficial option was option 5 which had the following attributes:

- Land is less expensive at the new site;
- The new site is fully serviced, the existing site is on a septic system;
- Access to GO bus service; and
- Closer to the centre of Town for dispatch.

Original design proposals included the renovation of the existing (1973 vintage) building with a new operations centre that was a five minute walk away. An internal analysis indicated that all buildings should be contiguous and meet future accessibility requirements. The Old Town Hall sat basically vacant for four years and the cost of rehabilitation for accessibility and asbestos removal was cost prohibitive.

Following an in-depth analysis, IHDSL'S Board of Directors gave direction to demolish the old building and build a new facility on t hat Town Campus site. A purchase agreement was developed to sell 2.07 acres at the existing IHDSL site for $925k and purchase 3.5 acres at the Old Town Hall site for $650k. All transactions are set at full appraised values.

The new IHDSL office and warehouse are scheduled to be completed in December 2013. The building is designed to be a 20 year plus, LEED Silver building accommodating long rage plans.

There is a letter of intent from the Town of Innisfil to lease surplus vehicle storage bays. Also, 5,500 sq' of future space is designed to be built as a base building and leased out until needed.

Innisfil Hydro's Existing Site

A property appraisal Executive Summary for 2061 and 2073 Commerce Park Drive in Innisfil is attached in Appendix 1. The appraisal provides a detailed summary of the legal and property descriptions. The area of the three buildings is as follows:

2073 – Main Office	3,133 sq'	
2061 – Engineers Office	3,680 sq'	
2073 – Carriage House (Storage)	1,315 sq'	1,315 sq' warehouse
Total usable office space	8,128 sq'	

Using Government Office Space Standards of 250 sq' per person[1], (this includes common areas), the existing usable office space can accommodate 32.5 people. The existing staff complement of 35 + 3 co-op students currently exceeds space requirements by 17%. The twenty year plan calculates the need for 75 employees and an additional 10,600 sq' of office space.

Analyzing the existing office scenario, the following major deficiencies are noted:

1. All buildings do not meet accessibility requirements, all have stairs and no elevators.
2. Ten stair slip and fall incidences have been documented since 2009.
3. Inadequate parking available, staff routinely park on the grass over top of the septic system.
4. More office, septic, warehousing and parking space needs to be made available to meet current and long range space requirements.

[1] Government Office Space Standards, http://www.viu.ca/facilities/Campus_Development/PLANNING%20INFORMATION/Planning%20Information/BC%20Government%20Office%20Space%20Standards%202001.pdf

Following the investigation of five different options, the option to move to the Town of Innisfil Administrative campus was chosen. IHDSL will maintain the existing 1.3 acre storage yard which houses a 13.3kVA 44-27.6kV transformer station that has the provision of being doubled.

IHDSL's New Site

At the Town of Innisfil Administration Campus, 3.5 acres was purchased for the new Innisfil Hydro Office and Operations Centre (2147 Innisfil Beach Road). The existing building on site had a number of deficiencies including accessibility. Other deficiencies are outlined in the Designated Substances and Hazardous Materials Survey (Appendix 2). The existing building is scheduled to be demolished in the Fall of 2012.

A property appraisal Executive Summary for 2147 Innisfil Beach Road in Innisfil is attached in Appendix 3. The appraisal provides a detailed summary of the legal and property description.

The new building is expected to break ground in the Fall of 2012 with completion in December 2013. The first and second floor plans are attached in Appendix 4 & 5 and the site plan is in Appendix 6. The office area available (without warehousing and garage) is:

Office area – 19,325 sq' @ 250 sq'/person = 77 personnel

Rental Area – 5,550 sq' @ 250 sq' /person = 22 personnel

The new building should accommodate the projected need until year 2031. The rental area is the right wing of the building and will be required around year 2031. The bottom floor is ear-marked to be leased out as a medical centre and the top floor for a business development centre. IHDSL will expand into extra space as required when leases expire. The anticipated rate of return is estimated to be between 8.5% and 9.8% per year.

The garage area is being built to accommodate 10 large truck vehicles. The Town of Innisfil has provided a letter of intent to lease five truck parking bays at the appraised value.

The property sits between the Town of Innisfil's Public Works Yard, the South Simcoe Police Building and the Innisfil Recreational Complex. The pool of parking spots available is large on campus so parking is not anticipated to be a problem when hosting large events. The site is within 450 meters of GO bus service which is not available at the old facility.

The building has been registered as a LEED silver project and will avoid the extra costs associated with the gold registration.

With this new building location IHDSL will improve accessibility to its customers, and improve the health and safety for our employees (existing and future). Additionally, we are anticipating an improved response time by being centrally collocated on the Town of Innisfil Campus and higher density development area.

APPENDIX 1

PROPERTY APPRAISAL EXECUTIVE SUMMARY

2061 and 2073 COMMERCE PARK DRIVE, INNISFIL

EXECUTIVE SUMMARY

Intended Users	Innisfil Hydro Distribution Systems Limited
Address	2061 & 2073 Commerce Park Drive, Innisfil, ON
Legal Description	2061 Commerce Park Drive – PIN # 580620124 Lot 27, Plan 1640 (Innisfil), in the Town of Innisfil, County of Simcoe 2073 Commerce Park Drive – PIN # 580620125 Lot 28, Plan 1640 (Innisfil), S/T Execution 99-00979, if enforceable, in the Town of Innisfil, County of Simcoe
Registered Owner	The Hydro Electric Commission of the Corporation of the Town of Innisfil (Innisfil Hydro)
Effective Date	January 12, 2012

PROPERTY:

Lot Size	2061 Commerce Park Drive	1.07 acres
	2073 Commerce Park Drive	1.00 acres
	Total Site Area	2.07 acres
Building GFA	2073 - Main Office	3,133 sq.ft.
	2061 - Engineers Office	3,680 sq.ft.
	2073 - Carriage House (Storage)	2,730 sq.ft.
	Total (both sites)	9,543 sq.ft.
Official Plan Designation	Special Highway Commercial Area	
Zoning	CBP - Commercial Business Park	
Present Use	Offices for Innisfil Hydro	
Highest and Best Use - Land	Permitted development within zoning guidelines	
Highest and Best Use - Impr.	Continued use as a mixed use commercial property	

VALUATION:

Purpose of the Appraisal To estimate market value for an internal review.

Value Estimates

2073 Commerce Park Drive	**$550,000**
2061 Commerce Park Drive	**$500,000**
Combined Subject Property	**$925,000**

It should be noted that two portables are situated on the subject property and have not been included in the value estimates as indicated above. Based on a previous consulting letter dated April 2008, we identified the combined value of the portables to be in the range of $36,000 to $40,000. Assuming that no major changes have been made to the portables, these value estimates provided would still apply.

INTRODUCTION

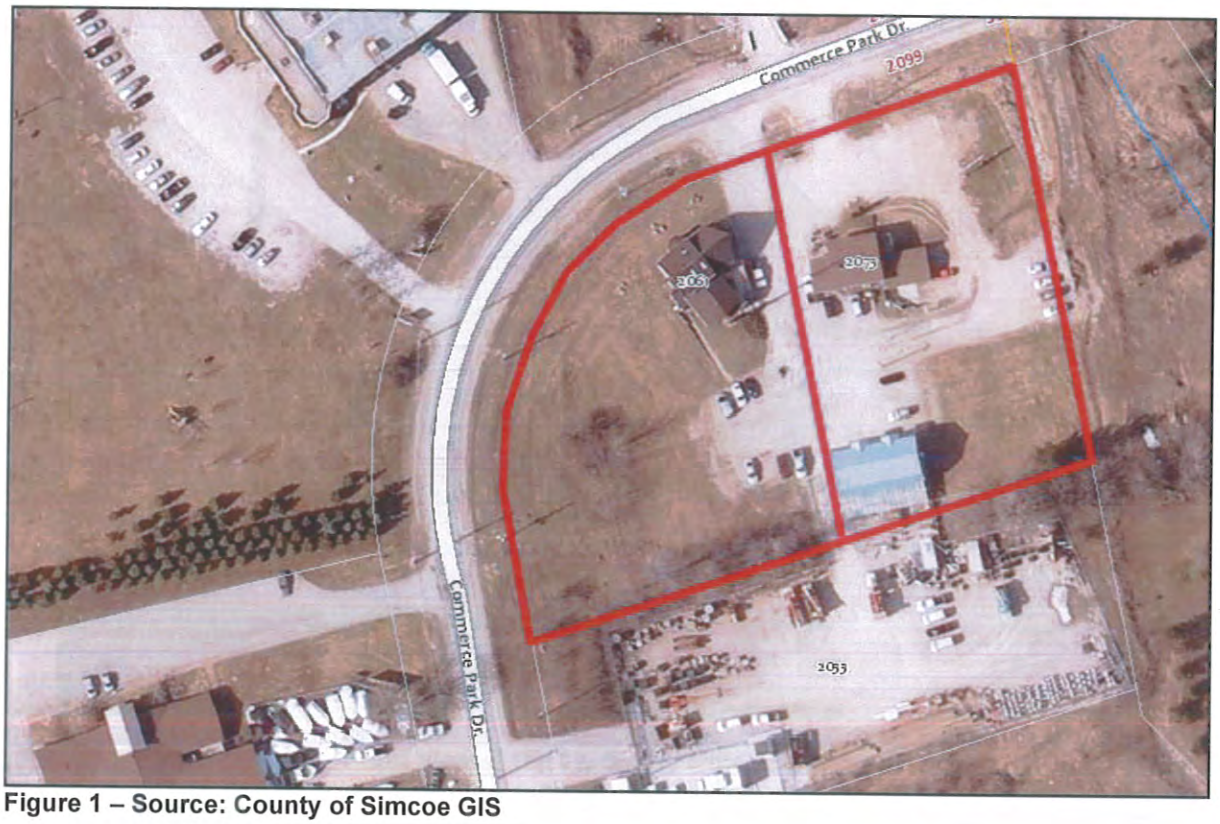

Figure 1 – Source: County of Simcoe GIS

The subject property represents a 2.07 acre property improved with three detached Pan-Abode log buildings. The subject property and improvements were originally designed as a home builder's sales office and were constructed in a piecemeal fashion. The buildings include a 1½ storey, and 1 storey, and a carriage house. The 1½ storey and 1 storey are utilized as office space while the carriage house is utilized as storage space with office space on the second level. The unorthodox development plan is considered less practical than typical single mixed use commercial buildings, which maximize land functionality.

Overall the site has good access, average exposure and adequate paved parking facilities. Direct commercial exposure is limited as the subject does not back onto Highway 400. However, the commercial properties that do back onto the highway along Commerce Park Drive provide favourable indirect access to Highway 400.

As per the client's instructions, we have supplied a value of the subject property as if sold separately (2061 Commerce Park Drive & 2073 Commerce Park Drive) and as if sold as a combined site.

PHOTOGRAPHS OF THE SUBJECT PROPERTY

Front View of the 1½ Storey Office Building

Exterior Rear View of the 1½ Storey Office Building

Front View of the 1 Storey Office Building

Rear View of the 1 Storey Office Building

Front View of the Carriage House

Rear View of the Carriage House

APPENDIX 2

DESIGNATED SUBSTANCES AND HAZARDOUS MATERIALS SURVEY

REPORT
TO
MCKNIGHT CHARRON LAURIN INC. ARCHITECTS

DESIGNATED SUBSTANCES AND HAZARDOUS MATERIALS SURVEY
INNISFIL MUNICIPAL OFFICE BUILDING
2147 INNISFIL BEACH ROAD
INNISFIL, ONTARIO

Prepared by:

DECOMMISSIONING CONSULTING SERVICES LIMITED
121 Granton Drive, Unit 11
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CANADA

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August 2012

701651-000

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701651-000

8 August 2012

McKnight Charron Laurin Inc. Architect
67 High Street
Barrie, Ontario
L4N 1W5

Attention: Mr. Michael McKnight

Re: **Designated Substances and Hazardous Materials Survey**
Innisfil Municipal Office Building
2147 Innisfil Beach Road, Innisfil, Ontario

Dear Mr. McKnight:

We are pleased to submit our report on the above.

We trust that the enclosed is suitable for your current purposes. Please call if you have any questions.

Yours very truly,

DECOMMISSIONING CONSULTING SERVICES LIMITED

Ada Nguyen, Dipl. Tech
Technical Specialist

Kelly Smith, B.Sc.
Project Manager

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1.0 INTRODUCTION

Decommissioning Consulting Services Limited (DCS) was retained by McKnight Charron Laurin Inc. to conduct a designated substances and hazardous materials survey of the Innisfil Municipal Office Building located at 2147 Innisfil Beach Road, Innisfil, Ontario. The building was reportedly constructed in the early 1970s.

It is our understanding that the designated substances and hazardous materials survey is required to ensure that all materials of concern are handled accordingly prior to the demolition of the building.

The survey was undertaken to report on the presence or suspected presence of readily observable designated substances and hazardous materials.

1.1 SCOPE OF WORK

The scope of work for our investigation included:

- inspection of readily-accessible areas of the building for the presence of designated substances and hazardous materials used in building construction materials;
- obtaining representative bulk samples of materials suspected of containing asbestos and paint chip samples;
- laboratory analyses of bulk samples for asbestos content and analysis of paint chip samples for lead content; and
- preparation of a report outlining the findings of the investigation.

Ms. Ada Nguyen and Mr. Dwayne Kellyman of DCS visited the site on 20 July 2012 to conduct the designated substances and hazardous materials survey at 2147 Innisfil Beach Road.

2.0 BACKGROUND INFORMATION ON DESIGNATED SUBSTANCES AND HAZARDOUS MATERIALS

Legal Requirements

Occupational Health and Safety Act (OHSA)

The Occupational Health and Safety Act (OHSA) sets out, in very general terms, the duties of employers and others to protect workers from health and safety hazards on the job. These duties include, but are not limited to:

- taking all reasonable precautions to protect the health and safety of workers [clause 25(2)(h)],
- ensuring that equipment, materials and protective equipment are maintained in good condition [clause 25(1)(b)],
- providing information, instruction and supervision to protect worker health and safety [clause 25(2)(a)], and
- acquainting a worker or a person in authority over a worker with any hazard in the work and in the handling, storage, use, disposal and transport of any article, device, equipment or a biological, chemical or physical agent [clause 25(2)(d)].

In addition, section 30 of the OHSA deals with the presence of designated substances on construction projects. Compliance with the OHSA and its regulations requires action to be taken where there is a designated substance hazard on a construction project.

Section 30 of the OHSA requires the owner of a project to determine if designated substances are present on a project and, if so, to inform all potential contractors as part of the bidding process. Contractors who receive this information are to pass it onto other contractors and subcontractors who are bidding for work on the project.

Regulation for Construction Projects, 0. Reg. 213/91

The Regulation for Construction Projects, 0. Reg. 213/91, applies to all construction projects. The following sections of the regulation would apply to situations where there is the potential for workers to be exposed to designated substances:

Section 14 (5) A competent person shall perform tests and observations necessary for the detection of hazardous conditions on a project.

Section 21 (1) A worker shall wear such protective clothing and use such personal protective equipment or devices as are necessary to protect the worker against the hazards to which the worker may be exposed.

(2) A worker's employer shall require the worker to comply with subsection (1).

(3) A worker required to wear personal protective clothing or use personal protective equipment or devices shall be adequately instructed and trained in the care and use of the clothing, equipment or device before wearing or using it.

Section 30 Workers who handle or use substances likely to endanger their health shall be provided with washing facilities with clean water, soap and individual towels.

Section 46 (1) A project shall be adequately ventilated by natural or mechanical means,

(a) if a worker may be injured by inhaling a noxious gas, vapour, dust or fume;

(2) If it is not practicable to provide natural or mechanical ventilation in the circumstances described in clause (1)(a), respiratory protective equipment suitable for the hazard shall be provided and be used by the workers.

Section 59 If the dissemination of dust is a hazard to a worker, the dust shall be adequately controlled or each worker who may be exposed to the hazard shall be provided with adequate personal protective equipment.

Regulation for Designated Substances (0. Reg. 490/09)

The Designated Substance Regulation (O. Reg. 490/09, specifies occupational exposure lim its (OELs) for designated substances and requires an assessm ent and a control program to ensure compliance with these OELs

Although, 0. Reg. 490/09 and the OELs do not apply to an employer on a construction project, or to their workers at the project, employers still have a responsibility to prot ect the health of their workers and to comply with the OHSA and other applicable regulations. Section 25(2)(h) of the OHSA requires that employers take "every precaution reasonable in the circumstances for the protection of a worker".

Other regulatory requirements (and guidelines) which apply to control of exposure to designated substances and hazardous materials are referenced in the sections below.

2.1 ASBESTOS

Asbestos has been widely used in buildings, both in friable applications (materials which can be crumbled, pulverized or powdered by hand pressure, when dry) such as pipe and tank insulation, sprayed-on fireproofing and acoustic texture m aterial and in non-friable manufactured products such as floor tile, gask ets, cement board and so on. The use of asbestos in friable application s was curtailed around the mid-1970s and, as such, most buildings constructed prior to about 1975 contain some form of friable construction material with an asbestos content. The use of asbestos in certain non-friable materials continued beyond the mid-1970s.

Control of exposure to as bestos is governed in On tario by Regulation 278/05 – *Designated Substance – Asbestos on Construction Projects and in Buildings and Repair Operations*. Disposal of asbestos waste (fri able and non-friable materials) is governed by Ontario Regulation 278/05 and by Ontario Regulation 347, Waste Management – Gener al. O.Reg. 278/05 classifies asbestos work operations into th ree types (Type 1, 2 and 3), as shown in Table C-1 in Appendix C, and specifies procedures to be followed in conducting asbestos abatement work.

2.2 LEAD

Lead is a heavy metal that can be found in construction materials such as paints, coatings, mortar, concrete, pipes, solder, packings, sheet metal, caulking, glazed ceramic products and cable splices. Lead has been used historically in exterior and interior paints.

The *Surface Coating Materials Regulations* made under the *Hazardous Products Act* (SOR/2005-109) sets a maximum concentration of total lead of 90 mg/kg (0.009 percent or 90 parts per million) for surface coating materials, including paints, effective 21 October 2010. This criterion level applies to the sale and importation of new surface coating materials.

The National Plumbing Code allowed lead as an acceptable material for pipes until 1975 and in solder until 1986.

The Ministry of Labour *Guideline, Lead on Construction Projects,* dated April 2011, provides guidance in the measures and procedures that should be followed when handling lead-containing materials during construction projects. In the guideline, lead-containing construction operations are classified into three groups - Type 1 (low risk), Type 2 (medium risk) and Type 3 (high risk) based on presumed airborne concentrations of lead, as shown in Appendix C, Table C-2. Any operation that may expose a worker to lead that is not a Type 1, Type 2, or Type 3b operation, is classified as a Type 3a operation.

2.3 MERCURY

Mercury has been used in electrical equipment such as alkaline batteries, fluorescent light bulbs (lamps), high intensity discharge (HID) lights (mercury vapour, high pressure sodium and metal halide), "silent switches" and in instruments such as thermometers, manometers and barometers, pressure gauges, float and level switches and flow meters. Mercury-containing lamps, the bulk of which are 1.22 m (four foot) fluorescent lamps contain between 7 and 40 mg of mercury each. Mercury compounds have also been used by many manufacturers historically as additives in latex paint to protect the paint from mildew and bacteria during production and storage.

The intentional addition of mercury to Canadian-produced consumer paints for interior use was prohibited in 1991. Mercury may have remained in paints after 1991, however, as a result of impurities in the paint ingredients or cross-contamination due to other manufacturing processes. The *Surface Coating Materials Regulations* made under the *Hazardous Products Act* set a

maximum total mercury concentration of 10 mg/kg (0.001 percent) for surface coating materials (including paint). This criterion level applies to the sale and importation of new surface coating materials.

Mercury-containing thermostats and silent light switches are mercury tilt switches which are small tubes with electrical contacts at one end of the tube. A mercury tilt switch is usually present when no switch is visible. Mercury switches often have the word "TOP" stamped on the upper end of the switch, which is visible after removing the cover plate. If mercury switches are to be removed, the entire switch should be removed and placed into a suitable container for storage and disposal.

No special requirements exist in Ontario for disposal of small quantities (i.e., less than 30) of waste light tubes. Larger quantities of waste light tubes (more than 30) generated during renovations or building demolition and waste mercury from equipment must either be recycled or disposed of in accordance with the requirements of Ont. Reg. 347 - *Waste Management, General*.

Waste mercury in amounts less than 5 kg (per month) are exempt from the generator registration requirements prescribed by O.Reg. 347 – *Waste Management – General*. Waste mercury from mercury switches or gauges should, however, be properly collected and shipped to a recycling facility or disposed of as a hazardous waste. Removal of mercury-containing equipment (e.g., switches, gauges, controls, etc.) should be carried out in a manner which prevents spillage and exposure to workers.

2.4 SILICA

Silica exists in several forms of which crystalline silica is of most concern with respect to potential worker exposures. Quartz is the most abundant type of crystalline silica. Some commonly used construction materials containing silica include brick, refractory brick, concrete, concrete block, cement, mortar, rock and stone, sand, fill dirt, topsoil and asphalt containing rock or stone.

The Ministry of Labour Guideline, *Silica on Construction Projects*, dated April 2011, provides guidance in controlling exposure to silica dust during construction activities. In the guideline, silica-containing construction operations are classified into three groups - Type 1 (low risk), Type 2 (medium risk) and Type 3 (high risk) based on presumed airborne concentrations of

respirable crystalline silica in the form of cristobalite, tridymite, quartz and tripoli as shown in Appendix C, Table C-3.

2.5 VINYL CHLORIDE

Vinyl chloride vapours may be released from polyvinyl chloride (PVC) products in the event of heating or as a result of decomposition during fire. PVC is used in numerous materials that may be found in building construction, including, for example, piping, conduits, siding, window and door frames, plastics, garden hoses, flooring and wire and cable protection.

2.6 ACRYLONITRILE

Acrylonitrile is used to produce nitrile-butadiene rubber, acrylonitrile-butadiene-styrene (ABS) polymers and styrene-acrylonitrile (SAN) polymers. Products made with ABS resins which may be found in buildings include telephones, bottles, packaging, refrigerator door liners, plastic pipe, building panels and shower stalls. Acrylonitrile can be released into the air by combustion of products containing ABS.

2.7 OTHER DESIGNATED SUBSTANCES

Isocyanates are a class of chemicals used in the manufacture of certain types of plastics, foams, coatings and other products. Isocyanate-based building construction materials may include rigid foam products such as foam-core panels and spray-on insulation and paints, coatings, sealants and adhesives. Isocyanates may be inhaled if they are present in the air in the form of a vapour, a mist or a dust.

Benzene is a clear, highly flammable liquid used mainly in the manufacture of other chemicals. The commercial use of benzene as a solvent has practically been eliminated, however it continues to be used as a solvent and reactant in laboratories.

Arsenic is a heavy metal used historically in pesticides and herbicides. The primary use in building construction materials was its use in the wood preservative chromated copper arsenate (CCA). CCA was used to pressure treat lumber since the 1940's. Pressure-treated wood containing CCA is no longer being produced for use in most residential settings.

Ethylene oxide is a colourless gas at room temperature. it has been used primarily for the manufacture of other chemicals, as a fumigant and fungicide and for sterilization of hospital equipment.

Coke oven emissions are airborne contaminants emitted from coke ovens and are not a potential hazard associated with building construction materials.

2.8 PCBs

The management of equipment classified as waste and containing Polychlorinated Biphenyls (PCBs) at concentrations of 50 parts per million (mg/kg) or greater is regulated by *Ontario Regulation 362, Waste Management* – PCBs. Under this regulation, PCB waste is defined as any waste material containing PCBs in concentrations of 50 mg/kg or greater. Any equipment containing PCBs at or greater than this level, such as transformers, switchgear, light ballasts and capacitors, which is removed from service due to age, failure or as a result of decommissioning, is considered to constitute a PCB waste. Although current federal legislation (effective 1 July 1980) has prohibited the manufacture and sale of new equipment containing PCBs since that time, continued operation of equipment supplied prior to this date and containing PCBs is still permitted. Handling, storage and disposition of such equipment is, however, tightly regulated and must be managed in accordance with provincial and federal government requirements as soon as it is taken out of service or becomes unserviceable.

In most institutional, commercial facilities and in smaller industrial facilities, the primary source of equipment potentially containing PCBs is fluorescent and H.I.D. light ballasts. Small transformers may also be present. In larger industrial facilities, larger transformers and switch gear containing, or potentially containing, PCBs may also be present.

PCBs were also commonly added to industrial paints from the 1940s to the late 1970s. PCBs were added directly to the paint mixture to act as a fungicide, to increase durability and flexibility, to improve resistance to fires and to increase moisture resistance. The use of PCBs in new products was banned in Canada in the 1970s. PCB amended paints were used in speciality industrial/institutional applications prior to the 1970s including government buildings and equipment such as industrial plants, radar sites, ships as well as non-government rail cars, ships, grain bins, automobiles and appliances.

Caulking containing PCBs was used in buildings in the 1950s through the 1970s. In general, buildings built after 1978 do not contain PCBs in caulking.

Removal of in-service equipment containing PCBs, such as fluorescent light ballasts, capacitors and transformers, is subject to the requirements of the federal *PCBs Regulations* (discussed below). When the PCB materials are classified as waste, jurisdiction falls under the Ontario Ministry of the Environment (MOE) and O.Reg. 362. All remedial and PCB management work must be carried out under the terms of a Director's Instruction issued by an MOE District Office (for quantities of PCB fluid greater than 50 litres). The PCB waste stream, regardless of quantity, must be registered with the MOE, in accordance with O.Reg. 347, General - Waste Management. O.Reg. 362 applies to any equipment containing greater than 1 kg of PCBs. Current MOE policies will, therefore, allow a one-time disposal of up to 40 ballasts as municipal waste. For quantities greater than 40, the ballasts must be classified as PCB waste and either placed into temporary storage or disposed of at an acceptable facility.

Amendments to the federal PCB regulations were passed into law on 17 September 2008. The key aspects of the new *PCBs Regulations* (superseding the Chlorobiphenyls Regulations and the Storage of PCB Materials Regulations), enacted under the *Canadian Environmental Protection Act* (CEPA), are the establishment of end of use dates for all equipment containing PCBs and storage/disposal requirements.
The regulations require that:

- all in-service PCB equipment containing PCBs >50 mg/kg at child care facilities, schools (preschool, primary and secondary), hospitals, senior citizens' care facilities, food or feed processing plants and drinking water treatment plants be removed from service by 31 December 2009;

- PCB waste stored on properties occupied by child care facilities, schools (preschool, primary and secondary), hospitals, senior citizens' care facilities, food or feed processing plants and drinking water treatment plants, and/or land within 100 m of the above properties, be removed from the storage facility and disposed of by 31 December 2009;

- all equipment having PCB concentrations >500 mg/kg at all other locations be removed from service by 31 December 2009;

- all equipment having PCB concentrations >50 mg/kg be removed from service by 31 December 2025;
- PCB-containing equipment be placed into suitable storage or disposed of at a suitable facility within 30 days following removal from service; and

- release of PCBs to the environment be limited to new more stringent limits, including 2 mg/kg PCBs for liquids and 50 mg/kg for solids containing PCBs, and a maximum of 1 gram from capacitors, transformers and other equipment containing PCBs.

Exceptions are provided for fluorescent light ballasts and pole-mounted transformers where an end of use date of 31 December 2025 has been specified. The regulations also limit the storage of PCB material to a maximum of one year from the date the regulations came into effect or one year following removal of the equipment from service, whichever is the later date.

The regulations also allow for the filing of applications for exemption from the applicable end of use dates specified above. There are a number of circumstances under which an application may be filed. The maximum end of use date cannot, however, extend beyond 31 December 2014. In addition to the above, there are several other requirements, including filing of annual reports, notification for changes in inventories for stored PCBs, and so forth.

2.9 OZONE-DEPLETING SUBSTANCES

Under *Ontario Regulation 189/94, Refrigerants, amended by 0.Reg. 180/07*, with respect to chiorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs) and hydrofluorocarbons (HFCs), the most significant requirements for handling of refrigerants with respect to the ongoing operation of building air conditioning systems include the following:

- certification is required for all persons testing, repairing, filling or emptying equipment containing CFCs;

- the release of CFCs and HCFCs to the environment is prohibited;

- the sale of refrigerants is restricted to certain conditions;

- records of the servicing and repair of equipment containing CFCs and HCFCs must be prepared and maintained by the owner of the equipment; and

- equipment no longer containing CFCs and HCFCs must be posted with a notice completed by a certified person.

Ontario Regulation 347, General Waste Management, has also been amended to provide for more strict control of CFCs. The requirements under the amended regulation apply primarily to the keeping of records for the receipt or recycling of CFC waste.

Any ODS-containing equipment to be removed must be handled in the following manner:

- any equipment designated for disposal as scrap must be drained of its contents by a licensed technician and equipped with a label indicating that the equipment no longer contains any refrigerant. The specific requirements for information on the label, as specified in the regulation, must be adhered to;

- equipment designated for relocation must be drained and labelled as above; and

- any equipment that is drained to facilitate relocation must be tested for leaks prior to re filling. The equipment must be re-filled within six months of the leak test.

2.10 MOULD

Moulds are forms of fungi that are found everywhere both indoors and outdoors all year round. Outdoors, moulds live in the soil, on plants and on dead and decaying matter. More than 1000 different kinds of indoor moulds have been found in buildings. Moulds spread and reproduce by making spores, which are all small and light-weight, able to travel through air, capable of resisting dry, adverse environmental conditions, and hence capable of surviving a long time. Moulds need moisture and nutrients to grow and their growth is stimulated by warm, damp and humid conditions.

Control of exposure to mould is required under Section 25(2)(h) of the *Ontario Occupational Health and Safety Act*, which states that employers shall take every precaution reasonable in the circumstances for the protection of workers. Recommended work practices are outlined in the following documents:

- Information Bulletin - *Abatement and Mould Remediation in Construction.* Ontario Ministry of Labour. January 2000; and

- *Mould Guidelines for the Canadian Construction Industry.* Standard Construction Document CCA 82 2004. Canadian Construction Association.

- *Mould Abatement Guidelines.* Environmental Abatement Council of Ontario. Edition 2. 2010.

3.0 RESULTS AND DISCUSSION

DCS reviewed the report entitled "*Phase I Environmental Site Assessment, 2147 Innisfil Beach Road, Innisfil, Ontario"*, prepared by Trow Associates Inc., dated 20 June 2005 (the Trow report). Information obtained from this report was utilized by DCS during the course of our investigation and in the preparation of this report.

3.1 ASBESTOS

During the course of our designated substances and hazardous materials survey, representative and confirmatory bulk samples of materials were collected by DCS staff. The samples were forwarded to EMSL Canada Inc., a commercial laboratory in Mississauga, Ontario for asbestos analysis. Results of bulk sample analysis for asbestos content are provided in Table 3.1. Laboratory reports are provided in Appendix B. Bulk sampling of building materials suspected of containing asbestos was carried out in order to meet the minimum sampling requirements specified in Table 1 of O.Reg. 278/05.

TABLE 3.1

SUMMARY OF RESULTS OF ANALYSIS OF BULK SAMPLES FOR ASBESTOS CONTENT

SAMPLE Nº	SAMPLE LOCATION	SAMPLE DESCRIPTION	ASBESTOS CONTENT
1A-VFT-201	Room 201	12" vinyl floor tile, beige w/ brown streaks	**2.1% chrysotile**
1A-MS-201	Room 201	Mastic below vinyl floor tile	None detected (PLM) None detected (TEM)
2A-VSF-200	Room 200	Vinyl sheeting w/ paper backing, grey pebble pattern	**5.1% chrysotile**
3A-MS-206	Room 206	Mastic below carpet	None detected (PLM) None detected (TEM)
4A-SCT-200	Room 200	2' x 4' suspended ceiling tile, pinholes, rough surface	**1% amosite** **4% chrysotile**
5A-JC-200	Room 200	Drywall joint compound	**1.2% chrysotile**
6A-VSF-212	Room 212	Vinyl sheeting, large stone pattern w/ paper backing	**19.4% chrysotile**
6A-MS-212	Room 212	Mastic below vinyl sheeting	<0.27% chrysotile(1) None detected (TEM)
7A-VFT-104	Room 104	12" vinyl sheeting, cream w/ cream specks	None detected (PLM) None detected (TEM)
7B-VFT-104	Room 104	12" vinyl sheeting, cream w/ cream specks	None detected

SAMPLE Nº	SAMPLE LOCATION	SAMPLE DESCRIPTION	ASBESTOS CONTENT
7C-VFT-104	Room 104	12" vinyl sheeting, cream w/ cream specks	None detected
7A-MS-104	Room 104	Mastic below vinyl floor tile	None detected (PLM) None detected (TEM)
8A-VSF-104	Room104	Vinyl sheeting, beige w/ blue, grey, pink spots	None detected (PLM) None detected (TEM)
8B-VSF-104	Room104	Vinyl sheeting, beige w/ blue, grey, pink spots	None detected
8C-VSF-104	Room104	Vinyl sheeting, beige w/ blue, grey, pink spots	None detected
9A-CK-108	Room 108	Caulking on door frame, grey	None detected (PLM) None detected (TEM)
9B-CK-108	Room 108	Caulking on door frame, grey	None detected
9C-CK-108	Room 108	Caulking on door frame, grey	None detected
10A-PF-108	Room 108	Pipe fitting insulation, brown powder	**1% amosite** **<1% chrysotile**
11A-PS-108	Room 108	Pipe straight insulation, antisweat	None detected
11B-PS-108	Room 108	Pipe straight insulation, antisweat	None detected
11C-PS-108	Room 108	Pipe straight insulation, antisweat	None detected
12A-CK-108	Room108	Window caulking, interior, brown	<0.25% chrysotile(1) None detected
12B-CK-205	Room 205	Window caulking, interior, brown	None detected
12C-CK-204	Room 204	Window caulking, interior, brown	None detected
13A-PF-108	Room 108	Pipe fitting insulation, grey cement	**10% chrysotile**
14A-PF-115	Room 115	Pipe fitting insulation, drain pipe, grey cement	**12% chrysotile**
15A-SCT-115	Room 115	2' x 4' suspended ceiling tile, random fissures	None detected
15B-SCT-114	Room 114	2' x 4' suspended ceiling tile, random fissures	None detected
15C-SCT-117	Room 117	2' x 4' suspended ceiling tile, random fissures	None detected
16A-CK-120	Room 120	Caulking on door frame, interior, white	None detected (PLM) None detected (TEM)
16B-CK-120	Room 120	Caulking on door frame, interior, white	None detected
16C-CK-120	Room 120	Caulking on door frame, interior, white	None detected
17A-CK-121	Room 121	Caulking on door frame, exterior, brown, btwn glass & frame	None detected (PLM) None detected (TEM)
17B-CK-121	Room 121	Caulking on door frame, exterior, brown, btwn glass & frame	None detected
17C-CK-121	Room 121	Caulking on door frame, exterior, brown, btwn glass & frame	None detected
18A-CK-121	Room 121	Caulking on door frame, exterior, red, btwn brick & frame	<0.25% chrysotile (PLM & TEM)(1)
18B-CK-121	Room 121	Caulking on door frame, exterior, red, btwn brick & frame	<0.25% chrysotile(1)

SAMPLE Nº	SAMPLE LOCATION	SAMPLE DESCRIPTION	ASBESTOS CONTENT
18C-CK-120	Room 120	Caulking on door frame, exterior, red, btwn brick & frame	<0.25% chrysotile(1)
19A-CK-EXT	Exterior	Caulking on window, black, btwn glass & frame	**1.5% chrysotile**
20A-CK-EXT	Exterior	Caulking on window, black, btwn brick & frame	None detected (PLM) None detected (TEM)
20B-CK-EXT	Exterior	Caulking on window, black, btwn brick & frame	None detected
20C-CK-EXT	Exterior	Caulking on window, black, btwn brick & frame	None detected
21A-CK-EXT	Exterior	Wall joint caulking, grey	<0.25% chrysotile (PLM & TEM)(1)
21B-CK-EXT	Exterior	Wall joint caulking, grey	<0.25% chrysotile(1)
21C-CK-EXT	Exterior	Wall joint caulking, grey	0.29% chrysotile(1)
22A-CK-EXT	Exterior	Wall joint caulking, brown	None detected (PLM) None detected (TEM)
22B-CK-EXT	Exterior	Wall joint caulking, brown	None detected
22C-CK-EXT	Exterior	Caulking on fascia, brown	None detected
23A-CK-EXT	Exterior	Caulking on vent louvre on rooftop, black	<0.25% chrysotile (PLM & TEM)(1)
23B-CK-EXT	Exterior	Caulking on vent louvre on rooftop, black	<0.25% chrysotile(1)
23C-CK-EXT	Exterior	Caulking on vent louvre on rooftop, black	0.34% chrysotile(1)
24A-TAR-ROOF	Rooftop	Roof membrane, top layer, rubber	None detected (PLM) None detected (TEM)
25A-VP-ROOF	Rooftop	Vapour barrier on steel deck, mop down	None detected (PLM) None detected (TEM)
26A-CK-EXT	Rooftop	Caulking on air handling unit, black	None detected (PLM) None detected (TEM)
26B-CK-EXT	Rooftop	Caulking on air handling unit, black	None detected
26C-CK-EXT	Rooftop	Caulking on air handling unit, black	None detected

NOTES:

< = Less than.
Chrysotile = Chrysotile asbestos.
Amosite = Amosite asbestos.

(1) "Asbestos-containing material" is defined as material that contains 0.5% or more asbestos by dry weight.

Bulk samples were analyzed by Polarized Light Microscopy (PLM) analysis, except where "TEM" is noted, in which case Transmission Electron Microscopy analysis was also performed.

Determination of the locations of asbestos-containing materials was made based on the results of bulk sample analysis, visual observations and physical characteristics of the applications as well as our knowledge of the uses of asbestos in building materials. The locations of accessible asbestos-containing materials are identified on the floor plans provided in Appendix A.

Glass fibre insulation is readily visually distinguishable (typically yellow in colour) from asbestos-containing insulation materials and was, therefore, not tested for asbestos content. All thermal insulation, with the exception of glass fibre material, should be assumed to contain asbestos unless a bulk sample analysis indicates otherwise.

Based on visual observations and results of laboratory analyses of samples, the following asbestos-containing materials were found to be present in the building:

- thermal insulation applied to pipe fittings below ceiling in Mechanical Room 108 and Sump Room 116;
- vinyl floor tiles (12" x 12") in Rooms 116, 201, 203 and Corridor 110;
- vinyl sheet flooring in Rooms 104, 115, 200, 211 and Corridor 212;
- drywall joint compound applied to drywall walls and ceilings throughout the first and second floors;
- ceiling tiles (2' x 4') throughout the first and second floors; and
- exterior window caulking applied between the glass and metal frames throughout the building.

It should be noted that the ceiling space in Room 210 was not accessible due to the height of the ceiling. A scissor lift or scaffolding will be required to permit safe access to the ceilings space. The ceiling space should be inspected prior to demolition work for the presence of any asbestos-containing materials.

Vinyl floor tiles, vinyl sheet flooring and caulking are non-friable materials. Removal of these non-friable asbestos-containing materials can be performed as a Type 1 operation as specified in O. Reg. 278/05 if the material is wetted and the work is done only using non-powered, hand-held

tools (see Table C-1 in Appendix C). If the removal work is done using power tools that are attached to dust-collecting devices equipped with HEPA filters, then the work is classified as Type 2. If the power tools do not have HEPA filtered dust collecting devices, then the work is Type 3.

Removal of less than 7.5 m^2 of asbestos-containing ceiling tiles is classified as a Type 1 operation in accordance with O.Reg. 278/05 – *Regulation respecting Asbestos on Construction Projects and in Buildings and Repair Operations* – made under the Occupational Health and Safety Act. Removal of 7.5 m^2 or more of asbestos-containing ceiling tiles is a Type 2 operation.

Removal of less than one square metre of drywall in which asbestos-containing joint filling compounds have been used is classified as a Type 1 operation. Removal of one square metre or more of drywall with asbestos-containing joint compounds is a Type 2 operation.

Thermal insulation is a friable material. Removal of less than 1 m^2 of friable asbestos-containing materials is classified as a Type 2 enclosure or glovebag operations as specified in O.Reg. 278/05. Removal of more than 1 m^2 of friable asbestos-containing materials is classified as a Type 3 or glovebag operations.

Asbestos may also be present in materials which were not sampled during the course of the asbestos survey carried out by DCS, including, but not limited to fire doors, cementitious levelling compound under vinyl flooring, grout, gaskets in piping, internal components of boilers, paints and coatings, components of electrical equipment (e.g. electric wiring insulation, non-metallic sheathed cable, electrical panel partitions, arc chutes, high-grade electrical paper, etc.), concrete, asphaltic pavement, etc., and/or in locations that are presently inaccessible (e.g., in pipe chases and behind walls). Asbestos may also be present in the form of vermiculite insulation in cavities in concrete or cement block walls (used as in-fill insulation). Confirmatory testing of any such materials could be undertaken as the need arises (i.e., at the time of renovations, modifications or demolition) or the materials can be assumed to contain asbestos based on findings in adjacent areas.

If any materials which may contain asbestos and which were not tested during the course of the designated substances survey are discovered during any construction activities, the work shall not proceed until such time as the required notifications have been made and an appropriate course of action is determined.

3.2 LEAD

Three paint chip and two mortar samples were collected by DCS during the course of the survey. Samples were submitted to Maxxam Analytics in Mississauga, Ontario for analysis of lead content. The results of analysis are presented in Table 3.2.

Lead was detected at a level of 2,100 mg/kg in the sample of beige wall paint, 160 mg/kg in the sample of brown wall paint and 150 mg/kg in the sample of pink wall paint. Lead was not detected (i.e. less than the limit of detection of 5 ug/g) in both samples of the masonry and brick mortar.

If paint (or other lead-containing coatings or materials) will be disturbed during the course of construction work, the measures and procedures outlined in the Ministry of Labour *Guideline – Lead on Construction Projects* should be followed. Additional information on the classification of work involving lead is provided in Appendix C, Table C-2.

Lead may also be present in glazing on ceramic tiles, in the solder on the seals of bell joints of any cast iron drainpipe and in the solder on the sweated-on joints between copper pipe and fittings.

TABLE 3.2

SUMMARY OF RESULTS OF ANALYSES OF BULK SAMPLES FOR LEAD CONTENT

SAMPLE Nº	SAMPLE LOCATION	SAMPLE DESCRIPTION	LEAD CONTENT
1-beige-206	Room 206	Beige paint – wall	2,100 mg/kg
2-brown-200	Room 200	Brown paint – wall	160 mg/kg
3-pink-104	Room 104	Pink paint – wall	150 mg/kg
4-mortar-115	Room 115	Masonry mortar – interior	<5 ug/g
5-mortar-ext	Exterior	Brick mortar – exterior	<5 ug/g

NOTE:

< = less than.

3.3 MERCURY

During the course of our site inspections, fluorescent lights (T8s) were observed throughout the building. Mercury should be assumed to be present as a gas in all fluorescent light tubes. Mercury-containing thermostats were observed in Rooms 108, 115, 116, 200 and 201. Mercury should also be assumed to be present in paint applications (albeit likely in low concentrations).

The measures and procedures outlined in the MOL *Guideline – Lead on Construction Projects* for control of potential exposure to lead in paint during construction activities will also serve to control potential exposure to any mercury in paint.

Proper procedures for removing mercury-containing equipment (thermostats, for example, and any other mercury-containing equipment found to be present at the time of renovations or demolition) typically involve:

- removal of the mercury-containing equipment in a manner designed to prevent breakage;
- removal of the equipment over or in a containment device sufficient to collect and contain any mercury released in case of breakage;
- ensuring that a mercury clean-up system is readily available to immediately transfer any mercury resulting from spills or leaks from broken equipment and that any mercury resulting from spills or leaks is immediately transferred to an appropriate container;
- ensuring that the area in which equipment is removed is well ventilated;
- ensuring that employees removing equipment are thoroughly familiar with proper waste mercury handling and emergency procedures, including transfer of mercury from containment devices to appropriate containers;
- storing removed switches in closed, non-leaking containers that are in good condition; and

- packing removed switches in the container with packing materials adequate to prevent breakage during storage, handling and transportation.

3.4 SILICA

Materials observed in the building which should be considered to contain silica included gypsum board, drywall joint compound, concrete, cement block walls, marblestone, and cementitious levelling compound under vinyl sheet flooring and vinyl floor tiles.

Silica can also be assumed to be present in any gravel ballast on roofs and will also be found in asphalt roofing materials if rock or stone are present in the asphalt.

The Ministry of Labour Guideline, *Silica on Construction Projects*, dated September 2004, provides guidance in controlling exposure to silica dust during construction activities. In the guideline, silica-containing construction operations are classified into three groups - Type 1 (low risk), Type 2 (medium risk) and Type 3 (high risk) based on presumed airborne concentrations of silica, as shown in Appendix C, Table C-3.

Additional precautionary measures should also be considered for certain types of materials (e.g. plaster and texture coat materials, including non-asbestos applications). For minor disturbances such as drilling, a HEPA-filtered attachment should be used. For removal of more than a minor amount of material, enclosures would be appropriate for dust control and separation of the work area from adjacent areas.

3.5 VINYL CHLORIDE

As mentioned in Sections 2.5 above, vinyl chloride would only be a potential exposure concern in the event of combustion of PVC products.

3.6 ACRYLONITRILE

As mentioned in Section 2.6 above, acrylonitrile would only be a potential exposure concern in the event of construction of ABS products.

3.7 OTHER DESIGNATED SUBSTANCES

No other designated substances (benzene, isocyanates, arsenic, ethylene oxide and coke oven emissions) were observed to be present in the building, and none would be expected to be encountered in any building materials in a form that would represent an exposure concern. Arsenic may be present at low levels in paint applications. The measures and procedures outlined in the MOL *Guideline – Lead on Construction Projects* for control of potential exposure to lead in paint during construction activities will also serve to control potential exposure to any arsenic (or mercury) in paint.

3.8 PCBS

Fluorescent lights were observed in the facility during the course of our site inspections. Light ballasts, such as those associated with the type of fluorescent lights (T8s) observed in the building, do not contain PCBs.

It should be noted that the light fixtures in Room 210 were not accessible due to the height of the ceiling. If light ballasts, such as those associated with the type of fluorescent lights (T12s) are present, they may contain PCBs.

In order to verify if a ballast contains PCBs or not, the date code stamped on the bottom (or back) of the ballast should be checked on each ballast removed by an electrician at the time of dismantling of the lights for comparison with information published by the manufacturers and by the federal government regarding which ballasts contain PCB fluids. Any ballasts manufactured prior to January 1980 should be assumed to contain PCBs unless otherwise indicated. The publication entitled Identification of Lamp Ballasts Containing PCBs, Report EPS 2/CC/2 (revised), by Environment Canada, dated August 1991, provides guidance in this regard. It should be noted that most manufacturers in the U.S. and Canada voluntarily discontinued the manufacture of PCB-containing ballasts in the late 1970s. It is possible, therefore, that ballasts manufactured between mid-1978 and 1980 do not contain PCBs.

DCS reviewed the report entitled "*Phase I Environmental Site Assessment, 2147 Innisfil Beach Road, Innisfil, Ontario"*, prepared by Trow Associates Inc., dated 20 June 2005 (the Trow report). The Trow report indicated that the transformer adjacent to the building do not contain PCBs.

3.9 OZONE-DEPLETING SUBSTANCES

A portable air conditioning unit observed in Room 202 may contain ozone-depleting substances (ODS).

If any ODS-containing equipment is to be removed then they must be handled in the following manner:

- any equipment designated for disposal as scrap must be drained of its contents by a licensed technician and equipped with a label indicating that the equipment no longer contains any refrigerant. The specific requirements for information on the label, as specified in the regulation, must be adhered to;

- equipment designated for relocation to another facility must be drained and labelled, as above; and

- any equipment that is drained to facilitate relocation to another facility must be tested for leaks prior to re-filling. The equipment must be re-filled within six months of the leak test.

3.10 MOULD

The investigation for mould included a visual inspection of readily-accessible surfaces throughout the building to determine if any mould was evident. No suspect mould was observed in the building.

The inspection of mould was limited to visual observations of readily-accessible surfaces and did not include intrusive inspections of wall cavities. Hidden mould may be present in these areas. Mould should be assumed to be present on surfaces inside wall cavities (e.g. on gypsum board, etc.), under exterior cladding and possibly in other "hidden" areas. During renovations or demolition, any mould-impacted materials should be misted or wetted with water to reduce airborne dust. The materials should then be placed into a disposal bin and sealed. Workers involved in the demolition of mould-impacted materials should wear appropriate protective clothing and equipment and follow decontamination practices as outlined in the Canadian Construction Association Standard Construction Document CCA-82 2004 - Mould guidelines for the Canadian Construction Industry.

4.0 USE AND LIMITATIONS OF THIS DESIGNATED SUBSTANCES AND HAZARDOUS MATERIALS SURVEY REPORT

This report, prepared for McKnight Charron Laurin Inc. Architects, does not provide certification or warranty, expressed or implied, that the investigation conducted by DCS identified all designated substances (as defined in the *Ontario Occupational Health and Safety Act*) at the subject facility. The work undertaken by DCS was directed to provide information on the presence of designated substances in building construction materials based on visual inspection of readily accessible areas in the building and on the results of laboratory analysis of a limited number of bulk samples of material for asbestos content and laboratory analysis of a limited number of paint samples for lead content. The survey did not include for identification of asbestos in process materials, equipment (including electrical equipment and wiring), furniture (e.g. chairs, table tops, chalkboards, etc.), nor material outside of the building (e.g. asphaltic pavement).

The material in this report reflects DCS' best judgment in light of the information available at the time of the investigation, which was performed on 20 July 2012. It should be noted that mould growth can occur following the date of inspection.

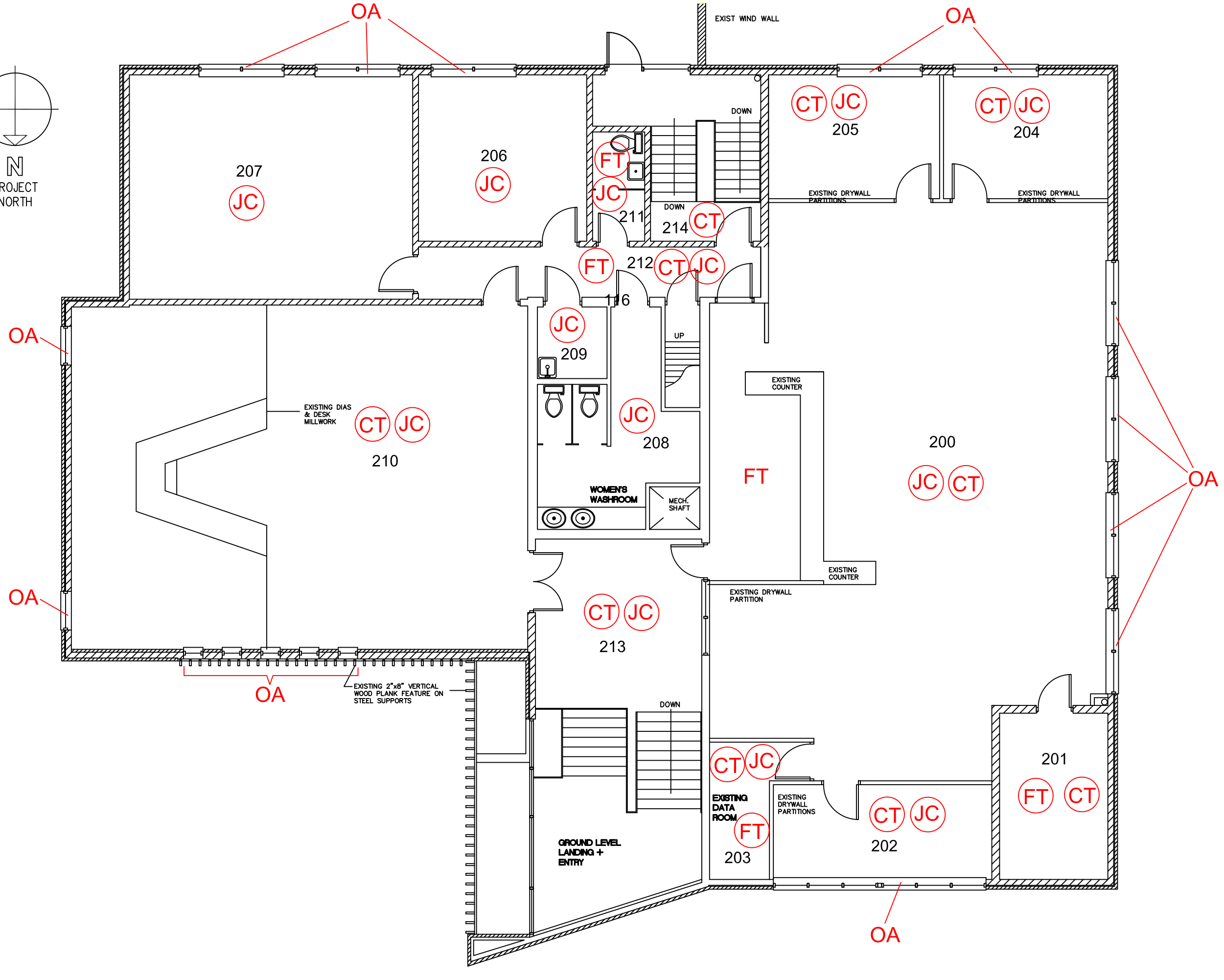
This report was prepared by DCS for McKnight Charron Laurin Inc. Architects. Any use which any other party makes of the report, or reliance on, or decisions to be based on it, is the responsibility of such parties.

APPENDIX A

FLOOR PLANS

APPENDIX 2 pg 29

N
PROJECT NORTH



LEGEND:

205 FUNCTIONAL SPACE

◯ THROUGHOUT FUNCTIONAL SPACE

CT ASBESTOS CEILING TILE

FT ASBESTOS FLOORING

JC ASBESTOS DRYWALL JOINT COMPOUND

Pf ASBESTOS ON PIPE FITTINGS

OA OTHER ASBESTOS MATERIALS

NOTES:

1.

REVISIONS:

No.	Date:	By:	Revisions

REFERENCE:

1. MCKNIGHT CHARRON LAURIN INC.
JOB NO. 08-015, SHEET NO. A2.2, DATE: June 16, 2008

DCS
DECOMMISSIONING CONSULTING SERVICES LIMITED

MCKNIGHT CHARRON LAURIN INC.
ARCHITECTS

LOCATIONS OF ASBESTOS-CONTAINING MATERIALS

INNISFIL MUNICIPAL OFFICE
2101 INNISFIL BEACH ROAD, INNISFIL, ONT.
UPPER FLOOR PLAN

Drawn By: P.A.L.	Approved By: A.T.N.	Project No: 701651	
Date: AUGUST 2012	Scale: N.T.S	Drawing No: 701651-2	

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APPENDIX 2 pg 30

N
PROJECT NORTH

OA
Pf
GRADE EXIT
CORRECT EXIST. DAMP CONDITIONS
Pf
HWT
EXISTING MECH / ELEC ROOM
EXISTING PANEL ROOM
107
JC CT
108
CT
109
CT
120
UP
112
STAT STOR
JC
OA
JC CT
LUNCH ROOM
113
STOVE
MICRO
D.W.
FRIDGE
EXISTING DRYWALL FURRING
110
BY-LAWS
114
JC
EXISTING DRYWALL PARTITION AND COLUMN FURRING
OA
CT
106
111 MEN'S STAFF WASHROOM
JC
119
EXISTING DRYWALL PARTITIONS
EXISTING CUBICLE PARTITIONS
EXISTING CUBICLE PARTITIONS
EXISTING DRYWALL PARTITIONS
CT
105
104
JC CT
JC
PUBLIC WASHROOM
101
JC
FEMALE STAFF WASHROOM
102
FT
OA
EXISTING COUNTER
115
JC
OA
FT
JC CT
100
EXISTING CUBICLE PARTITIONS
EXISTING COUNTER
103
JC
CT
118
EXISTING STACKED MASONRY PLANTER
EXISTING DRYWALL PARTITIONS
EXIST. STAIR DOWN
EXIST. STAIR UP
117
FT
CT
SUMP PIT
116
EXISTING ENTRY
EXIST. SECTION
121
JC CT
JC
Pf
12" DIA. PIPE
OA

LEGEND:

112	FUNCTIONAL SPACE
◯	THROUGHOUT FUNCTIONAL SPACE
CT	ASBESTOS CEILING TILE
FT	ASBESTOS FLOORING
JC	ASBESTOS DRYWALL JOINT COMPOUND
Pf	ASBESTOS ON PIPE FITTINGS
OA	OTHER ASBESTOS MATERIALS

NOTES:

1.

REVISIONS:

No.	Date:	By:	Revisions

REFERENCE:

1. MCKNIGHT CHARRON LAURIN INC.
JOB NO. 08-015, SHEET NO. A2.1, DATE: June 16, 2008

DCS
DECOMMISSIONING CONSULTING SERVICES LIMITED

MCKNIGHT CHARRON LAURIN INC.
ARCHITECTS

LOCATIONS OF ASBESTOS-CONTAINING MATERIALS

INNISFIL MUNICIPAL OFFICE
2101 INNISFIL BEACH ROAD, INNISFIL, ONT.
LOWER FLOOR PLAN

Drawn By: P.A.L.	Approved By: A.T.N.	Project No: 701651	
Date: AUGUST 2012	Scale: N.T.S	Drawing No: 701651-1	

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APPENDIX B

LABORATORY REPORTS

EMSL Canada Inc.
10 Falconer Drive, Unit #3 Mississauga, ON L5N 3L8
Phone/Fax: 289-997-4602 / (289) 997-4607
http://www.emsl.com / torontolab@emsl.com

EMSL Canada Order: 551203331
Customer ID: 55DCSL97
Customer PO: 701651
Project ID:

Attn: Ada Nguyen
Decommissioning Consulting Services Ltd.
121 Granton Drive
Unit 11
Richmond Hill, ON L4B 3N4

Proj: 2147 INNISFIL BEACH ROAD

Phone: (905) 882-5984
Fax: (905) 882-8962
Collected:
Received: 7/23/2012
Analyzed: 7/30/2012

Test Report: Asbestos Analysis of Bulk Materials for Ontario Regulation 278/05 via EPA600/R-93/116 Method

Client Sample ID: 1A-VFT-201 ***Lab Sample ID:*** **551203331-0001**

Sample Description: ROOM 201/12" VINYL FLOOR TILE BEIGE W/BROWN STREAKS

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Gray	0.0%	97.9%	**2.1% Chrysotile**	
TEM Grav. Reduction	7/27/2012			Positive Stop (Not Analyzed)		

Client Sample ID: 1B-VFT-202 ***Lab Sample ID:*** **551203331-0002**

Sample Description: ROOM 202/12" VINYL FLOOR TILE BEIGE W/BROWN STREAKS

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012			Positive Stop (Not Analyzed)		

Client Sample ID: 1C-VFT-110 ***Lab Sample ID:*** **551203331-0003**

Sample Description: ROOM 110/12" VINYL FLOOR TILE BEIGE W/BROWN STREAKS

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012			Positive Stop (Not Analyzed)		

Client Sample ID: 1A-MS-201 ***Lab Sample ID:*** **551203331-0004**

Sample Description: ROOM 201/MASTIC BELOW VINYL FLOOR TILE

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Black	0.0%	100%	None Detected	
TEM Grav. Reduction	7/30/2012	Black	0.0%	100%	None Detected	

Client Sample ID: 2A-VSF-200 ***Lab Sample ID:*** **551203331-0005**

Sample Description: ROOM 200/VINYL SHEET FLOORING W/PAPER BACKING GREY PEBBLE PATTERN

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Gray	0.0%	94.9%	**5.1% Chrysotile**	
TEM Grav. Reduction	7/27/2012			Positive Stop (Not Analyzed)		

Client Sample ID: 2B-VSF-200 ***Lab Sample ID:*** **551203331-0006**

Sample Description: ROOM 200/VINYL SHEET FLOORING W/PAPER BACKING GREY PEBBLE PATTERN

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012			Positive Stop (Not Analyzed)		

Client Sample ID: 2C-VSF-200 ***Lab Sample ID:*** **551203331-0007**

Sample Description: ROOM 200/VINYL SHEET FLOORING W/PAPER BACKING GREY PEBBLE PATTERN

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012			Positive Stop (Not Analyzed)		

EMSL Canada Inc.
10 Falconer Drive, Unit #3 Mississauga, ON L5N 3L8
Phone/Fax: 289-997-4602 / (289) 997-4607
http://www.emsl.com / torontolab@emsl.com

EMSL Canada Order: 551203331
Customer ID: 55DCSL97
Customer PO: 701651
Project ID:

Test Report: Asbestos Analysis of Bulk Materials for Ontario Regulation 278/05 via EPA600/R-93/116 Method

Client Sample ID: 3A-MS-206 **Lab Sample ID:** 551203331-0008
Sample Description: ROOM 206/MASTIC BELOW CARPET

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Tan	0.0%	100%	None Detected	
TEM Grav. Reduction	7/30/2012	Tan	0.0%	100%	None Detected	

Client Sample ID: 4A-SCT-200 **Lab Sample ID:** 551203331-0009
Sample Description: ROOM 200/2'X4' SUSPENDED CEILING TILE PINHOLES ROUGH SURFACE

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM	7/27/2012		0%	95%	**1% Amosite**	
					4% Chrysotile	

Client Sample ID: 4B-SCT-212 **Lab Sample ID:** 551203331-0010
Sample Description: ROOM 212/2'X4' SUSPENDED CEILING TILE PINHOLES ROUGH SURFACE

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM	7/27/2012				Stop Positive (Not Analyzed)	

Client Sample ID: 4C-SCT-100 **Lab Sample ID:** 551203331-0011
Sample Description: ROOM 100/2'X4' SUSPENDED CEILING TILE PINHOLES ROUGH SURFACE

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM	7/27/2012				Stop Positive (Not Analyzed)	

Client Sample ID: 5A-JC-200 **Lab Sample ID:** 551203331-0012
Sample Description: ROOM 200/DRYWALL JOINT COMPOUND

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Gray	0.0%	98.8%	**1.2% Chrysotile**	

Client Sample ID: 5B-JC-207 **Lab Sample ID:** 551203331-0013
Sample Description: ROOM 207/DRYWALL JOINT COMPOUND

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012				Positive Stop (Not Analyzed)	

Client Sample ID: 5C-JC-104 **Lab Sample ID:** 551203331-0014
Sample Description: ROOM 104/DRYWALL JOINT COMPOUND

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012				Positive Stop (Not Analyzed)	

Client Sample ID: 5D-JC-117 **Lab Sample ID:** 551203331-0015
Sample Description: ROOM 117/DRYWALL JOINT COMPOUND

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012				Positive Stop (Not Analyzed)	

EMSL Canada Inc.
10 Falconer Drive, Unit #3 Mississauga, ON L5N 3L8
Phone/Fax: 289-997-4602 / (289) 997-4607
http://www.emsl.com / torontolab@emsl.com

EMSL Canada Order: 551203331
Customer ID: 55DCSL97
Customer PO: 701651
Project ID:

Test Report: Asbestos Analysis of Bulk Materials for Ontario Regulation 278/05 via EPA600/R-93/116 Method

Client Sample ID: SE-JC-115 ***Lab Sample ID:*** **551203331-0016**

Sample Description: ROOM 115/DRYWALL JOINT COMPOUND

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012				Positive Stop (Not Analyzed)	

Client Sample ID: 6A-VSF-212 ***Lab Sample ID:*** **551203331-0017**

Sample Description: ROOM 212/VINYL SHEETING LARGE STONE PATTERN

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Brown /Gray	0.0%	80.6%	**19.4% Chrysotile**	
TEM Grav. Reduction	7/27/2012				Positive Stop (Not Analyzed)	

Client Sample ID: 6B-VSF-212 ***Lab Sample ID:*** **551203331-0018**

Sample Description: ROOM 212/VINYL SHEETING LARGE STONE PATTERN

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012				Positive Stop (Not Analyzed)	

Client Sample ID: 6C-VSF-104 ***Lab Sample ID:*** **551203331-0019**

Sample Description: ROOM 104/VINYL SHEETING LARGE STONE PATTERN

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012				Positive Stop (Not Analyzed)	

Client Sample ID: 6A-MS-212 ***Lab Sample ID:*** **551203331-0020**

Sample Description: ROOM 212/MASTIC BELOW VINYL SHEETING

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Brown	0.0%	100%	**<0.27% Chrysotile**	
TEM Grav. Reduction	7/30/2012	Brown	0.0%	100%	None Detected	

Client Sample ID: 7A-VFT-104 ***Lab Sample ID:*** **551203331-0021**

Sample Description: ROOM 104/12" VINYL SHEETING CREAM W/CREAM SPECKS

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Beige	0.0%	100%	None Detected	
TEM Grav. Reduction	7/30/2012	Beige	0.0%	100%	None Detected	

Client Sample ID: 7B-VFT-104 ***Lab Sample ID:*** **551203331-0022**

Sample Description: ROOM 104/12" VINYL SHEETING CREAM W/CREAM SPECKS

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Beige	0.0%	100%	None Detected	

Client Sample ID: 7V-VFT-104 ***Lab Sample ID:*** **551203331-0023**

Sample Description: ROOM 104/12" VINYL SHEETING CREAM W/CREAM SPECKS

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Beige	0.0%	100%	None Detected	

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Client Sample ID: 7A-MS-104 ***Lab Sample ID:*** **551203331-0024**

Sample Description: ROOM 104/MASTIC BELOW VINYL FLOOR TILE

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Black	0.0%	100%	None Detected	
TEM Grav. Reduction	7/30/2012	Black	0.0%	100%	None Detected	

Client Sample ID: 8A-VSF-104 ***Lab Sample ID:*** **551203331-0025**

Sample Description: ROOM 104/VINYL SHEETING BEIGE W/BLUE GREY PINK SPOTS

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Gray /Various	0.0%	100%	None Detected	
TEM Grav. Reduction	7/30/2012	Gray /Various	0.0%	100%	None Detected	

Client Sample ID: 8B-VSF-104 ***Lab Sample ID:*** **551203331-0026**

Sample Description: ROOM 104/VINYL SHEETING BEIGE W/BLUE GREY PINK SPOTS

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Gray /Various	0.0%	100%	None Detected	

Client Sample ID: 8C-VSF-104 ***Lab Sample ID:*** **551203331-0027**

Sample Description: ROOM 104/VINYL SHEETING BEIGE W/BLUE GREY PINK SPOTS

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Gray /Various	0.0%	100%	None Detected	

Client Sample ID: 8A-MS-104 ***Lab Sample ID:*** **551203331-0028**

Sample Description: ROOM 104/MASTIC BELOW VINYL SHEETING

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012				Insufficient Material	
TEM Grav. Reduction	7/30/2012				Insufficient Material	

Client Sample ID: 9A-CK-108 ***Lab Sample ID:*** **551203331-0029**

Sample Description: ROOM 108/CAULKING ON DOOR FRAME GREY

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Gray	0.0%	100%	None Detected	
TEM Grav. Reduction	7/30/2012	Gray	0.0%	100%	None Detected	

Client Sample ID: 9B-CK-108 ***Lab Sample ID:*** **551203331-0030**

Sample Description: ROOM 108/CAULKING ON DOOR FRAME GREY

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Gray	0.0%	100%	None Detected	

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Client Sample ID: 9C-CK-108 **Lab Sample ID:** 551203331-0031
Sample Description: ROOM 108/CAULKING ON DOOR FRAME GREY

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Gray	0.0%	100%	None Detected	

Client Sample ID: 10A-PF-108 **Lab Sample ID:** 551203331-0032
Sample Description: ROOM 108/PIPE FITTING INSULATION BROWN POWDER

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM	7/30/2012	Tan	35%	64%	**1% Amosite**	
					<1% Chrysotile	

Client Sample ID: 10B-PF-108 **Lab Sample ID:** 551203331-0033
Sample Description: ROOM 108/PIPE FITTING INSULATION BROWN POWDER

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM	7/30/2012				Stop Positive (Not Analyzed)	

Client Sample ID: 10C-PF-108 **Lab Sample ID:** 551203331-0034
Sample Description: ROOM 108/PIPE FITTING INSULATION BROWN POWDER

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM	7/30/2012				Stop Positive (Not Analyzed)	

Client Sample ID: 11A-PS-108 **Lab Sample ID:** 551203331-0035
Sample Description: ROOM 108/PIPE STRAIGHT INSULATION ANTISWEAT

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM	7/27/2012	Tan/Black	80%	20%	None Detected	

Client Sample ID: 11B-PS-108 **Lab Sample ID:** 551203331-0036
Sample Description: ROOM 108/PIPE STRAIGHT INSULATION ANTISWEAT

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM	7/27/2012	Tan/Black	80%	20%	None Detected	

Client Sample ID: 11C-PS-108 **Lab Sample ID:** 551203331-0037
Sample Description: ROOM 108/PIPE STRAIGHT INSULATION ANTISWEAT

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM	7/30/2012	Brown	90%	10%	None Detected	

Client Sample ID: 12A-CK-108 **Lab Sample ID:** 551203331-0038
Sample Description: ROOM 108/WINDOW CAULKING INTERIOR BROWN

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Brown	0.0%	100%	**<0.25% Chrysotile**	
TEM Grav. Reduction	7/30/2012	Brown	0.0%	100%	None Detected	

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Client Sample ID: 12B-CK-205 ***Lab Sample ID:*** **551203331-0039**

Sample Description: ROOM 205/WINDOW CAULKING INTERIOR BROWN

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Brown	0.0%	100%	None Detected	

Client Sample ID: 12C-CK-204 ***Lab Sample ID:*** **551203331-0040**

Sample Description: ROOM 204/WINDOW CAULKING INTERIOR BROWN

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Brown	0.0%	100%	None Detected	

Client Sample ID: 13A-PF-108 ***Lab Sample ID:*** **551203331-0041**

Sample Description: ROOM 108/PIPE FITTING INSULATION GREY CEMENT

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM	7/27/2012	Gray	0%	90%	**10% Chrysotile**	

Client Sample ID: 14A-PF-115 ***Lab Sample ID:*** **551203331-0042**

Sample Description: ROOM 115/PIPE FITTING INSULATION DRAIN PIPE GREY CEMENT

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM	7/27/2012	Tan	0%	88%	**12% Chrysotile**	

Client Sample ID: 15A-SCT-115 ***Lab Sample ID:*** **551203331-0043**

Sample Description: ROOM 115/2'X4' SUSPENDED CEILING TILE RANDOM FISSURES

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM	7/27/2012	Tan/White	80%	20%	None Detected	

Client Sample ID: 15B-SCT-114 ***Lab Sample ID:*** **551203331-0044**

Sample Description: ROOM 114/2'X4' SUSPENDED CEILING TILE RANDOM FISSURES

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM	7/27/2012	Tan/White	80%	20%	None Detected	

Client Sample ID: 15C-SCT-117 ***Lab Sample ID:*** **551203331-0045**

Sample Description: ROOM 117/2'X4' SUSPENDED CEILING TILE RANDOM FISSURES

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM	7/30/2012	Tan/White	80%	20%	None Detected	

Client Sample ID: 16A-CK-120 ***Lab Sample ID:*** **551203331-0046**

Sample Description: ROOM 120/CAULKING ON DOOR FRAME INTERIOR WHITE

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	White /Black	0.0%	100%	None Detected	
TEM Grav. Reduction	7/30/2012	White /Black	0.0%	100%	None Detected	

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Client Sample ID: 16B-CK-120 ***Lab Sample ID:*** **551203331-0047**

Sample Description: ROOM 120/CAULKING ON DOOR FRAME INTERIOR WHITE

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	White /Black	0.0%	100%	None Detected	

Client Sample ID: 16C-CK-120 ***Lab Sample ID:*** **551203331-0048**

Sample Description: ROOM 120/CAULKING ON DOOR FRAME INTERIOR WHITE

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	White /Black	0.0%	100%	None Detected	

Client Sample ID: 17A-CK-121 ***Lab Sample ID:*** **551203331-0049**

Sample Description: ROOM 121/CAULKING ON DOOR FRAME EXTERIOR BROWN BTWN GLASS & FRAME

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Brown	0.0%	100%	None Detected	
TEM Grav. Reduction	7/30/2012	Brown	0.0%	100%	None Detected	

Client Sample ID: 17B-CK-121 ***Lab Sample ID:*** **551203331-0050**

Sample Description: ROOM 121/CAULKING ON DOOR FRAME EXTERIOR BROWN BTWN GLASS & FRAME

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Brown	0.0%	100%	None Detected	

Client Sample ID: 17C-CK-121 ***Lab Sample ID:*** **551203331-0051**

Sample Description: ROOM 121/CAULKING ON DOOR FRAME EXTERIOR BROWN BTWN GLASS & FRAME

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Brown	0.0%	100%	None Detected	

Client Sample ID: 18A-CK-121 ***Lab Sample ID:*** **551203331-0052**

Sample Description: ROOM 121/CAULKING ON DOOR FRAME EXTERIOR RED BTWN BRICK & FRAME

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Red	0.0%	100%	**<0.25% Chrysotile**	
TEM Grav. Reduction	7/30/2012	Red	0.0%	99.8%	**<0.25% Chrysotile**	

Client Sample ID: 18B-CK-121 ***Lab Sample ID:*** **551203331-0053**

Sample Description: ROOM 121/CAULKING ON DOOR FRAME EXTERIOR RED BTWN BRICK & FRAME

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Red	0.0%	100%	**<0.25% Chrysotile**	

Client Sample ID: 18C-CK-120 ***Lab Sample ID:*** **551203331-0054**

Sample Description: ROOM 120/CAULKING ON DOOR FRAME EXTERIOR RED BTWN BRICK & FRAME

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Red	0.0%	100%	**<0.25% Chrysotile**	

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Client Sample ID: 19A-CK-EXT **Lab Sample ID:** 551203331-0055
Sample Description: EXTERIOR/CAULKING ON WINDOW BLACK BTWN GLASS & FRAME

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Black	0.0%	98.5%	**1.5% Chrysotile**	
TEM Grav. Reduction	7/27/2012			Positive Stop (Not Analyzed)		

Client Sample ID: 19B-CK-EXT **Lab Sample ID:** 551203331-0056
Sample Description: EXTERIOR/CAULKING ON WINDOW BLACK BTWN GLASS & FRAME

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012			Positive Stop (Not Analyzed)		

Client Sample ID: 19C-CK-EXT **Lab Sample ID:** 551203331-0057
Sample Description: EXTERIOR/CAULKING ON WINDOW BLACK BTWN GLASS & FRAME

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012			Positive Stop (Not Analyzed)		

Client Sample ID: 20A-CK-EXT **Lab Sample ID:** 551203331-0058
Sample Description: EXTERIOR/CAULKING ON WINDOW BLACK BTWN GLASS & FRAME

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Brown	0.0%	100%	None Detected	
TEM Grav. Reduction	7/30/2012	Brown	0.0%	100%	None Detected	

Client Sample ID: 20B-CK-EXT **Lab Sample ID:** 551203331-0059
Sample Description: EXTERIOR/CAULKING ON WINDOW BLACK BTWN GLASS & FRAME

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Brown	0.0%	100%	None Detected	

Client Sample ID: 20C-CK-EXT **Lab Sample ID:** 551203331-0060
Sample Description: EXTERIOR/CAULKING ON WINDOW BLACK BTWN GLASS & FRAME

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Brown	0.0%	100%	None Detected	

Client Sample ID: 21A-CK-EXT **Lab Sample ID:** 551203331-0061
Sample Description: EXTERIOR/WALL JOINT CAULKING GREY

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Gray	0.0%	100%	**<0.25% Chrysotile**	
TEM Grav. Reduction	7/30/2012	Gray	0.0%	99.8%	**<0.25% Chrysotile**	

Client Sample ID: 21B-CK-EXT **Lab Sample ID:** 551203331-0062
Sample Description: EXTERIOR/WALL JOINT CAULKING GREY

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Gray	0.0%	100%	**<0.25% Chrysotile**	

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Client Sample ID: 21C-CK-EXT **Lab Sample ID:** 551203331-0063
Sample Description: EXTERIOR/WALL JOINT CAULKING GREY

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Gray	0.0%	99.7%	**0.29% Chrysotile**	

Client Sample ID: 22A-CK-EXT **Lab Sample ID:** 551203331-0064
Sample Description: EXTERIOR/WALL JOINT CAULKING BROWN

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Brown	0.0%	100%	None Detected	
TEM Grav. Reduction	7/30/2012	Brown	0.0%	100%	None Detected	

Client Sample ID: 22B-CK-EXT **Lab Sample ID:** 551203331-0065
Sample Description: EXTERIOR/WALL JOINT CAULKING BROWN

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Brown	0.0%	100%	None Detected	

Client Sample ID: 22C-CK-EXT **Lab Sample ID:** 551203331-0066
Sample Description: EXTERIOR/CAULKING ON FASCIA BROWN

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Brown	0.0%	100%	None Detected	

Client Sample ID: 23A-CK-EXT **Lab Sample ID:** 551203331-0067
Sample Description: EXTERIOR/CAULKING ON VENT LOUVRE ON ROOFTOP BLACK

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Brown	0.0%	100%	**<0.25% Chrysotile**	
TEM Grav. Reduction	7/30/2012	Brown	0.0%	99.9%	**<0.25% Chrysotile**	

Client Sample ID: 23B-CK-EXT **Lab Sample ID:** 551203331-0068
Sample Description: EXTERIOR/CAULKING ON VENT LOUVRE ON ROOFTOP BLACK

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Brown	0.0%	100%	**<0.25% Chrysotile**	

Client Sample ID: 23C-CK-EXT **Lab Sample ID:** 551203331-0069
Sample Description: EXTERIOR/CAULKING ON VENT LOUVRE ON ROOFTOP BLACK

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Brown	0.0%	99.7%	**0.34% Chrysotile**	

Client Sample ID: 24A-TAR-ROOF **Lab Sample ID:** 551203331-0070
Sample Description: ROOFTOP/ROOF MEMBRANE TOP LAYER RUBBER

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Black /Yellow	0.0%	100%	None Detected	
TEM Grav. Reduction	7/30/2012	Black /Yellow	0.0%	100%	None Detected	

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Test Report: Asbestos Analysis of Bulk Materials for Ontario Regulation 278/05 via EPA600/R-93/116 Method

Client Sample ID: 25A-VP-ROOF ***Lab Sample ID:*** **551203331-0071**

Sample Description: ROOFTOP/VAPOUR BARRIER ON STEEL DECK MOP DOWN

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Black /Yellow	0.0%	100%	None Detected	
TEM Grav. Reduction	7/30/2012	Black /Yellow	0.0%	100%	None Detected	

Client Sample ID: 26A-CK-EXT ***Lab Sample ID:*** **551203331-0072**

Sample Description: ROOFTOP/CAULKING ON AIR HANDLING UNIT BLACK

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Black	0.0%	100%	None Detected	
TEM Grav. Reduction	7/30/2012	Black	0.0%	100%	None Detected	

Client Sample ID: 26B-CK-EXT ***Lab Sample ID:*** **551203331-0073**

Sample Description: ROOFTOP/CAULKING ON AIR HANDLING UNIT BLACK

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Black	0.0%	100%	None Detected	

Client Sample ID: 26C-CK-EXT ***Lab Sample ID:*** **551203331-0074**

Sample Description: ROOFTOP/CAULKING ON AIR HANDLING UNIT BLACK

TEST	Analyzed Date	Color	Non-Asbestos Fibrous	Non-Asbestos Non-Fibrous	Asbestos	Comment
PLM Grav. Reduction	7/27/2012	Black	0.0%	100%	None Detected	

Analyst(s)

Alice Feng	PLM Grav. Reduction	(47)
Lisa Podzyhun	PLM	(3)
Matthew Davis	PLM	(7)
Merriam Haffar	TEM Grav. Reduction	(18)

Kevin Pang
or other Approved Signatory

Any questions please contact Kevin Pang.

None Detected = <0.5%. EMSL maintains liability limited to cost of analysis. This report relates only to the samples reported above and may not be reproduced, except in full, without written approval by EMSL. EMSL bears no responsibility for sample collection activities or analytical method limitations. Interpretation and use of test results are the responsibility of the client. Samples received in good condition unless otherwise noted. This report must not be used to claim product endorsement by NVLAP of any agency of the U.S. Government.

Samples analyzed by EMSL Canada Inc. Mississauga, ON NVLAP Lab Code 200877-0

Initial report from: 07/30/201215:07:30

Your P.O. #: 701651
Your Project #: 701651
Site Location: 2147 INNISFIL BEACH
Your C.O.C. #: na

Attention: Ada Nguyen
Decommissioning Consulting Services Limited
121 Granton Dr
Unit 11
Richmond Hill, ON
L4B 3N4

Report Date: 2012/07/27

CERTIFICATE OF ANALYSIS

MAXXAM JOB #: B2B0389
Received: 2012/07/23, 13:06

Sample Matrix: Paint
Samples Received: 3

Analyses	Quantity	Date Extracted	Date Analyzed	Laboratory Method	Method Reference
Metals in Paint	3	2012/07/25	2012/07/25	CAM SOP-00408	SW-846 6010C

Sample Matrix: SOLID
Samples Received: 2

Analyses	Quantity	Date Extracted	Date Analyzed	Laboratory Method	Method Reference
Total Metals Analysis by ICP	2	2012/07/25	2012/07/26	CAM SOP-00408	SW-846 6010C

Remarks:

Maxxam Analytics has performed all analytical testing herein in accordance with ISO 17025 and the Protocol for Analytical Methods Used in the Assessment of Properties under Part XV.1 of the Environmental Protection Act. All methodologies comply with this document and are validated for use in the laboratory. The methods and techniques employed in this analysis conform to the performance criteria (detection limits, accuracy and precision) as outlined in the Protocol for Analytical Methods Used in the Assessment of Properties under Part XV.1 of the Environmental Protection Act. Reporting results to two significant figures at the RDL is to permit statistical evaluation and is not intended to be an indication of analytical precision.

The CWS PHC methods employed by Maxxam conform to all prescribed elements of the reference method and performance based elements have been validated. All modifications have been validated and proven equivalent following the 'Alberta Environment Draft Addenda to the CWS-PHC, Appendix 6, Validation of Alternate Methods'. Documentation is available upon request. Maxxam has made the following improvements to the CWS-PHC reference benchmark method: (i) Headspace for F1; and, (ii) Mechanical extraction for F2-F4. Note: F4G cannot be added to the C6 to C50 hydrocarbons. The extraction date for samples field preserved with methanol for F1 and Volatile Organic Compounds is considered to be the date sampled.

Maxxam Analytics is accredited by SCC (Lab ID 97) for all specific parameters as required by Ontario Regulation 153/04. Maxxam Analytics is limited in liability to the actual cost of analysis unless otherwise agreed in writing. There is no other

Maxxam Analytics International Corporation o/a Maxxam Analytics 6740 Campobello Road, Mississauga, Ontario, L5N 2L8 Tel: (905) 817-5700 Toll-Free: 800-563-6266 Fax: (905) 817-5777 www.maxxam.ca

Your P.O. #: 701651
Your Project #: 701651
Site Location: 2147 INNISFIL BEACH
Your C.O.C. #: na

Attention: Ada Nguyen
Decommissioning Consulting Services Limited
121 Granton Dr
Unit 11
Richmond Hill, ON
L4B 3N4

Report Date: 2012/07/27

CERTIFICATE OF ANALYSIS

warranty expressed or implied. Samples will be retained at Maxxam Analytics for three weeks from receipt of data or as per contract.

* RPDs calculated using raw data. The rounding of final results may result in the apparent difference.

Encryption Key

Please direct all questions regarding this Certificate of Analysis to your Project Manager.

Heather Jasumani, Campobello Customer Service
Email: Heather.Jasumani@maxxamanalytics.com
Phone# (905) 817-5700

==========

Maxxam has procedures in place to guard against improper use of the electronic signature and have the required "signatories", as per section 5.10.2 of ISO/IEC 17025:2005(E), signing the reports. For Service Group specific validation please refer to the Validation Signature Page.

Total cover pages: 2

Maxxam Job #: B2B0389
Report Date: 2012/07/27

Decommissioning Consulting Services Limited
Client Project #: 701651
Site Location: 2147 INNISFIL BEACH
Your P.O. #: 701651

ELEMENTS BY ATOMIC SPECTROSCOPY (PAINT)

Maxxam ID		OF7599	OF7599	OF7600	OF7601		
Sampling Date							
COC Number		na	na	na	na		
	Units	**1-BEIGE-206**	**1-BEIGE-206 Lab-Dup**	**2-BROWN-200**	**3-PINK-104**	**RDL**	**QC Batch**
Metals							
Lead (Pb)	mg/kg	2100	1000 (1)	160	150	50	2918341

RDL = Reportable Detection Limit
QC Batch = Quality Control Batch
(1) Duplicate results exceeded RPD acceptance criteria. This may be due to sample heterogeneity.

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Maxxam Job #: B2B0389
Report Date: 2012/07/27

Decommissioning Consulting Services Limited
Client Project #: 701651
Site Location: 2147 INNISFIL BEACH
Your P.O. #: 701651

ELEMENTS BY ATOMIC SPECTROSCOPY (SOLID)

Maxxam ID		OF7602	OF7603		
Sampling Date					
COC Number		na	na		
	Units	**4-MORTAR-115**	**5-MORTAR-EXT**	**RDL**	**QC Batch**
Metals					
Acid Extractable Lead (Pb)	ug/g	<5.0	<5.0	5.0	2918647

RDL = Reportable Detection Limit
QC Batch = Quality Control Batch

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Maxxam Job #: B2B0389
Report Date: 2012/07/27

Decommissioning Consulting Services Limited
Client Project #: 701651
Site Location: 2147 INNISFIL BEACH
Your P.O. #: 701651

Test Summary

Maxxam ID OF7599 **Collected**
Sample ID 1-BEIGE-206 **Shipped**
Matrix Paint **Received** 2012/07/23

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Metals in Paint	ICP	2918341	2012/07/25	2012/07/25	Archana Patel

Maxxam ID OF7599 Dup **Collected**
Sample ID 1-BEIGE-206 **Shipped**
Matrix Paint **Received** 2012/07/23

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Metals in Paint	ICP	2918341	2012/07/25	2012/07/25	Archana Patel

Maxxam ID OF7600 **Collected**
Sample ID 2-BROWN-200 **Shipped**
Matrix Paint **Received** 2012/07/23

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Metals in Paint	ICP	2918341	2012/07/25	2012/07/25	Archana Patel

Maxxam ID OF7601 **Collected**
Sample ID 3-PINK-104 **Shipped**
Matrix Paint **Received** 2012/07/23

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Metals in Paint	ICP	2918341	2012/07/25	2012/07/25	Archana Patel

Maxxam ID OF7602 **Collected**
Sample ID 4-MORTAR-115 **Shipped**
Matrix SOLID **Received** 2012/07/23

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Total Metals Analysis by ICP	ICP	2918647	2012/07/25	2012/07/26	Suban Kanapathippllai

Maxxam ID OF7603 **Collected**
Sample ID 5-MORTAR-EXT **Shipped**
Matrix SOLID **Received** 2012/07/23

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Total Metals Analysis by ICP	ICP	2918647	2012/07/25	2012/07/26	Suban Kanapathippllai

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Maxxam Job #: B2B0389
Report Date: 2012/07/27

Decommissioning Consulting Services Limited
Client Project #: 701651
Site Location: 2147 INNISFIL BEACH
Your P.O. #: 701651

Package 1	26.0°C

Each temperature is the average of up to three cooler temperatures taken at receipt

GENERAL COMMENTS

Results relate only to the items tested.

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Decommissioning Consulting Services Limited
Attention: Ada Nguyen
Client Project #: 701651
P.O. #: 701651
Site Location: 2147 INNISFIL BEACH

Quality Assurance Report

Maxxam Job Number: MB2B0389

QA/QC Batch Num	Init	QC Type	Parameter	Date Analyzed yyyy/mm/dd	Value	Recovery	Units	QC Limits
2918341	APT	Matrix Spike [OF7599-01]	Lead (Pb)	2012/07/25		NC	%	75 - 125
		QC Standard	Lead (Pb)	2012/07/25		109	%	75 - 125
		Method Blank	Lead (Pb)	2012/07/25	<50		mg/kg	
		RPD [OF7599-01]	Lead (Pb)	2012/07/25	69.3 (1)		%	35
2918647	SUK	Matrix Spike	Acid Extractable Lead (Pb)	2012/07/26		84	%	75 - 125
		Spiked Blank	Acid Extractable Lead (Pb)	2012/07/26		105	%	80 - 120
		Method Blank	Acid Extractable Lead (Pb)	2012/07/26	<5.0		ug/g	
		RPD	Acid Extractable Lead (Pb)	2012/07/26	NC		%	30

Duplicate: Paired analysis of a separate portion of the same sample. Used to evaluate the variance in the measurement.
Matrix Spike: A sample to which a known amount of the analyte of interest has been added. Used to evaluate sample matrix interference.
QC Standard: A blank matrix to which a known amount of the analyte has been added. Used to evaluate analyte recovery.
Spiked Blank: A blank matrix to which a known amount of the analyte has been added. Used to evaluate analyte recovery.
Method Blank: A blank matrix containing all reagents used in the analytical procedure. Used to identify laboratory contamination.
NC (Matrix Spike): The recovery in the matrix spike was not calculated. The relative difference between the concentration in the parent sample and the spiked amount was not sufficiently significant to permit a reliable recovery calculation.
NC (RPD): The RPD was not calculated. The level of analyte detected in the parent sample and its duplicate was not sufficiently significant to permit a reliable calculation.
(1) Duplicate results exceeded RPD acceptance criteria. This may be due to sample heterogeneity.

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Validation Signature Page

Maxxam Job #: B2B0389

The analytical data and all QC contained in this report were reviewed and validated by the following individual(s).

Cristina Carriere, Scientific Services

==========

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Maxxam Analytics International Corporation o/a Maxxam Analytics 6740 Campobello Road, Mississauga, Ontario, L5N 2L8 Tel: (905) 817-5700 Toll-Free: 800-563-6266 Fax: (905) 817-5777 www.maxxam.ca

APPENDIX C

SUMMARY OF ASBESTOS, LEAD AND SILICA WORK CLASSIFICATIONS

TABLE C-1
SUMMARY OF CLASSIFICATION OF TYPE 1, 2 AND 3 OPERATIONS (Ont. Reg. 278/05)

TYPE 1 OPERATIONS

- removing less than 7.5 m^2 asbestos-containing ceiling tiles;
- removing non-friable asbestos-containing material other than ceiling tiles, if the material is removed without being broken, cut, drilled, abraded, ground, sanded or vibrated;
- breaking, cutting, drilling, abrading, grinding, sanding or vibrating non-friable asbestos-containing material if the material is wetted and the work is done only using non-powered, hand-held tools; and
- removing less than 1 m^2 of drywall in which asbestos-containing joint compounds have been used.

TYPE 2 OPERATIONS

- removing all or part of a false ceiling to obtain access to a work area, if asbestos-containing material is likely to be lying on the surface of the false ceiling;
- removal of one square metre or less of friable asbestos-containing material;
- enclosing friable asbestos-containing material;
- applying tape or a sealant or other covering to asbestos-containing pipe or boiler insulation;
- removing 7.5 m^2 or more asbestos-containing ceiling tiles (if removed without being broken, cut, drilled, abraded, ground, sanded or vibrated);
- breaking, cutting, drilling, abrading, grinding, sanding or vibrating non-friable asbestos-containing material if the material is not wetted and the work is done only using non-powered, hand-held tools;
- removal of one square metre or more of drywall in which asbestos-containing joint compounds have been used;
- breaking, cutting, drilling, abrading, grinding, sanding or vibrating non-friable asbestos-containing material if the work is done using power tools that are attached to dust-collecting devices equipped with HEPA filters;
- cleaning or removing filters used in air-handling equipment in a building that has asbestos-containing sprayed fireproofing.

TABLE C-1 (Continued)
SUMMARY OF CLASSIFICATION OF TYPE 1, 2 AND 3 OPERATIONS (Ont. Reg. 278/05)

TYPE 3 OPERATIONS

- removal of more than one square metre of friable asbestos-containing material;
- spray application of a sealant to friable asbestos-containing material;
- cleaning or removing air-handling equipment, including rigid ducting but not including filters, in a building that has sprayed asbestos-containing fireproofing;
- repairing or demolishing a kiln, metallurgical furnace or similar structure that is made in part of asbestos-containing refractory materials;
- breaking, cutting, drilling, abrading, grinding, sanding or vibrating non-friable asbestos-containing materials, if the work is done using power tools that are not attached to dust-collecting devices equipped with HEPA filters.

TABLE C-2
SUMMARY OF CLASSIFICATION OF LEAD-CONTAINING CONSTRUCTION TASKS MOL GUIDELINE – LEAD ON CONSTRUCTION PROJECTS, SEPTEMBER 2004

Type 1 Operations	Type 2 Operations		Type 3 Operations	
	Type 2a	Type 2b	Type 3a	Type 3b
<0.05 mg/m^3	>0.05 to 0.50 mg/m^3	>0.50 to 1.25 mg/m^3	>1.25 to 2.50 mg/m^3	>2.50 mg/m^3

Note: The classification of Type 1, 2 and 3 operations is based on presumed airborne concentrations of lead, as shown above.

TYPE 1 OPERATIONS

- application of lead-containing coatings with a brush or roller;
- removal of lead-containing coatings with a chemical gel or paste and fibrous laminated cloth wrap;
- removal of lead-containing coatings or materials using a power tool that has an effective dust collection system equipped with a HEPA filter;
- installation or removal of lead-containing sheet metal;
- installation or removal of lead-containing packing, babbit or similar material;
- removal of lead-containing coatings or materials using non-powered hand tools, other than manual scraping or sanding;
- soldering.

TYPE 2 OPERATIONS

Type 2a Operations

- welding or high temperature cutting of lead-containing coatings or materials outdoors. This operation is considered a Type 2a operation only if it is short-term, not repeated, and if the material has been stripped prior to welding or high temperature cutting. Otherwise it will be considered a Type 3a operation;
- removal of lead-containing coatings or materials by scraping or sanding using non-powered hand tools;
- manual demolition of lead-painted plaster walls or building components by striking a wall with a sledgehammer or similar tool.

Type 2b Operations

- spray application of lead-containing coatings.

TABLE C-2 (Continued)
SUMMARY OF CLASSIFICATION OF LEAD-CONTAINING CONSTRUCTION TASKS
MOL GUIDELINE – LEAD ON CONSTRUCTION PROJECTS, SEPTEMBER 2004

TYPE 3 OPERATIONS

Type 3a Operations

- welding or high temperature cutting of lead-containing coatings or materials indoors or in a confined space;
- burning of a surface containing lead;
- dry removal of lead-containing mortar using an electric or pneumatic cutting device;
- removal of lead-containing coatings or materials using power tools without an effective dust collection system equipped with a HEPA filter;
- removal or repair of a ventilation system used for controlling lead exposure;
- demolition or cleanup of a facility where lead-containing products were manufactured;
- an operation that may expose a worker to lead dust, fume or mist that is not a Type 1, Type 2, or Type 3b operation

Type 3b Operations

- abrasive blasting of lead-containing coatings or materials;
- removal of lead-containing dust using an air mist extraction system.

TABLE C-3
SUMMARY OF CLASSIFICATION OF SILICA-CONTAINING CONSTRUCTION TASKS
MOL GUIDELINE, SILICA ON CONSTRUCTION PROJECTS, SEPTEMBER 2004

	Type 1 Operations	Type 2 Operations	Type 3 Operations
Cristobalite and Tridymite	>0.05 to 0.50 mg/m^3	>0.50 to 2.50 mg/m^3	>2.5 mg/m^3
Quartz and Tripoli	>0.10 to 1.0 mg/m^3	>1.0 to 5.0 mg/m^3	>5.0 mg/m^3

Note: The classification of silica-containing construction tasks is based on presumed concentrations of respirable crystalline silica, as shown above.

TYPE 1 OPERATIONS

- The drilling of holes in concrete or rock that is not part of a tunnelling operation or road construction.
- Milling of asphalt from concrete highway pavement.
- Charging mixers and hoppers with silica sand (sand consisting of at least 95 per cent silica) or silica flour (finely ground sand consisting of at least 95 per cent silica).
- Any other operation at a project that requires the handling of silica-containing material in a way that may result in a worker being exposed to airborne silica.
- Entry into a dry mortar removal or abrasive blasting area while airborne dust is visible for less than 15 minutes for inspection and/or sampling.
- Working within 25 metres of an area where compressed air is being used to remove silica-containing dust outdoors.

TYPE 2 OPERATIONS

- Removal of silica containing refractory materials with a jackhammer.
- The drilling of holes in concrete or rock that is part of a tunnelling or road construction.
- The use of a power tool to cut, grind, or polish concrete, masonry, terrazzo or refractory materials.
- The use of a power tool to remove silica containing materials.
- Tunnelling (operation of the tunnel boring machine, tunnel drilling, tunnel mesh installation).
- Tuckpoint and surface grinding.
- Dry mortar removal with an electric or pneumatic cutting device.
- Dry method dust cleanup from abrasive blasting operations.
- The use of compressed air outdoors for removing silica dust.
- Entry into area where abrasive blasting is being carried out for more than 15 minutes.

TABLE C-3 (Continued)
SUMMARY OF CLASSIFICATION OF SILICA-CONTAINING CONSTRUCTION TASKS
MOL GUIDELINE, SILICA ON CONSTRUCTION PROJECTS, SEPTEMBER 2004

TYPE 3 OPERATIONS

- Abrasive blasting with an abrasive that contains ≥ 1 per cent silica.

Abrasive blasting of a material that contains ≥ 1 per cent silica.

APPENDIX 3

PROPERTY APPRAISAL EXECUTIVE SUMMARY

2147 INNISFIL BEACH ROAD, INNISFIL

EXECUTIVE SUMMARY

Intended Users	Innisfil Hydro Distribution Systems Limited
Address	Part of 2147 Innisfil Beach Road, Innisfil, ON
Legal Description	Part of: Part of Lot 16, Concession 7, as in RO83378, RO112789 & RO333488, Except Parts 1 and 2 on Plan 51R35025, in the Town of Innisfil, County of Simcoe
PIN #	Part of 58064-0205
Registered Owner	The Corporation of the Town of Innisfil
Effective Date	January 12, 2012

PROPERTY:

Lot Size	3.0 acres (assumed)
Building Size	11,170 sq.ft.
Official Plan Designation	Institutional Area
Zoning	CS - Community Services
Present Use	The subject property is presently a vacant two storey single tenant institutional building formerly the municipal offices.
Highest and Best Use - Land	Permitted development within zoning guidelines
Highest and Best Use – Improved	Continued use as an institutional building if a user is available or alternatively demolition of the building and development as permitted within zoning guidelines

VALUATION:

Purpose of the Appraisal	To estimate market value to assist with an internal review

Value Estimates

Continued Use (If a User for the Building Is Available)	$650,000
For Redevelopment (If a User for the Building Is Not Available)	$470,000

BASIS OF THE APPRAISAL

This current short narrative report is intended for use only by Innisfil Hydro Distribution Systems Limited. The function of the report is to assist Innisfil Hydro Distribution Systems Limited with an internal review. Use of this report by others is not intended by the appraiser, and any liability in this respect is strictly denied.

We received our instructions from Mr. George Shaparew with Innisfil Hydro, who provided information on the property.

Prior to relying on this report for financing purposes, prudent review of the ability to service the loan is required.

TERMS OF REFERENCE

The following describes the provided or agreed to Terms of Reference for this assignment:

- We have been provided an aerial photograph outlining the proposed severance. We have been instructed to value the subject property, including buildings, as outlined on the aerial photograph provided.

EXTRAORDINARY ASSUMPTIONS AND LIMITING CONDITIONS OR HYPOTHETICAL CONDITIONS

An assumption is "that which is taken to be true". An extraordinary limiting condition is a necessary modification or exclusion of a standard rule. An extraordinary limiting condition may diminish the reliability of this report. The standard assumptions and limiting conditions are contained within this report.

The following Assumptions are highlighted as they relate to this report:

- Full compliance of the subject property with applicable Environmental Regulations and laws is assumed, unless otherwise stated, defined or considered in this report.
- It is assumed that all required licences, consents, or other legislative or administrative authority from any government or private entity organization either were or could have been obtained or renewed for any use which this report covers.
- It is assumed the subject property is free of contaminants or toxins at the effective date of valuation and furthermore that its soil possess sufficient load bearing characteristics to support future development without unusual costs or charges if such a use is contemplated by this report.

The following Extraordinary or Hypothetical Assumptions have been applied in this report:

1. We have assumed that the 3.0 acre subject property improved with the former municipal office building, as previously identified, is severed from the larger parcel.

2. There is currently a solar panel installation located near the rear of the site. It is our understanding that the Town of Innisfil is to retain the income from the solar panels. For the purposes of this report we have screened out any value impacts as a result of the solar panels currently installed on the site.

ANDREW, THOMPSON
& ASSOCIATES LTD.

642 Welham Road, Suite 103
Barrie, ON L4N 9A1
PHONE 705-721-1596 FAX 705-721-5183
WEB www.andrew-thompson.on.ca

ATA Real Estate Advisors

April 25, 2012

Innisfil Hydro Distribution Systems Limited
2073 Commerce Park Drive
Innisfil, ON L9S 4A2

Attention: Mr. George Shaparew

Re: Part of 2147 Innisfil Beach Road, Innisfil, ON

Dear Mr. Shaparew:

This letter is to be an addition to the appraisal report of "Part of 2147 Innisfil Beach Road, Innisfil" dated January 25, 2012. This letter is not considered an independent opinion in absence of that report and is to be read in conjunction with the originally prepared report.

The original report addressed the valuation of the former Innisfil Town Hall assumed to be situated on approximately 3 acres. The previous value conclusions summarized were:

- Value for a "continued use" $650,000
- Value for "redevelopment" $470,000

We have since been instructed that:

- The client requires a single estimate of value.
- The assumed site size has increased to 3.5 acres, an increase of 0.5 acres.
- An easement providing for services is to run along the front yard of the property.

It is our opinion that the "market value" of the subject property is best identified by the continued use of the subject building. The indicated value for "redevelopment" represents a secondary value in the case that a user is not available after a reasonable marketing and exposure time. It is reasonable to expect that if available on the open market, a user would arise for a continued use.

It is our opinion that the addition of 0.5 acres would not have an impact on its potential value to a continued user as it would not add any additional utility to the building, above what is provided by the originally assumed 3 acre site. It is also our opinion that the presence of a servicing easement crossing the property within the front yard will have no impact on the continued use or value of the subject property.

As of the original effective date of January 12, 2012, it is our opinion that the addition of 0.5 acres in site size and the registration of a servicing easement across the front yard will have no impact to the original estimate of value provided for a "continued use".

Therefore we conclude that the original concluded value of **$650,000** as of January 12, 2012 best provides a single estimate of value for the subject building as if on a 3.5 acre site.

We trust the information provided meets with your approval.

Respectfully Submitted,
ANDREW, THOMPSON AND ASSOCIATES LTD.

Peter Spivey, B.Sc., AACI, P.App
T:\REPORTS 2006\Innisfil\INNISFIL HYDRO 2008 & 2010 & 2012\IBR 2147, Mkt RentLetter & full report, HYDRO 2008 & 2012\2012 Report\Letter - April 24, 2012.docx

INTRODUCTION

For the purposes of this report the subject property (outlined in blue below) is assumed to be severed from the larger site (outlined in red below). The larger site represents a 9.66 acre property improved with a newly constructed police station, public works yard and the former Town of Innisfil Town Hall. The subject property is assumed to be a fully serviced 3.0 acre site improved with an 11,170 sq.ft. institutional building formerly the municipal offices. We have been advised that the potential site will have approximately 350 feet of frontage along Innisfil Beach Road.

The subject property is located near the intersection of Innisfil Beach Road and Yonge Street, slightly west of Alcona. The subject property is part of a large institutional campus that includes a newly developed recreation complex and the newly constructed municipal office.

Figure 1 – Source: County of Simcoe GIS

PHOTOGRAPHS OF THE SUBJECT PROPERTY

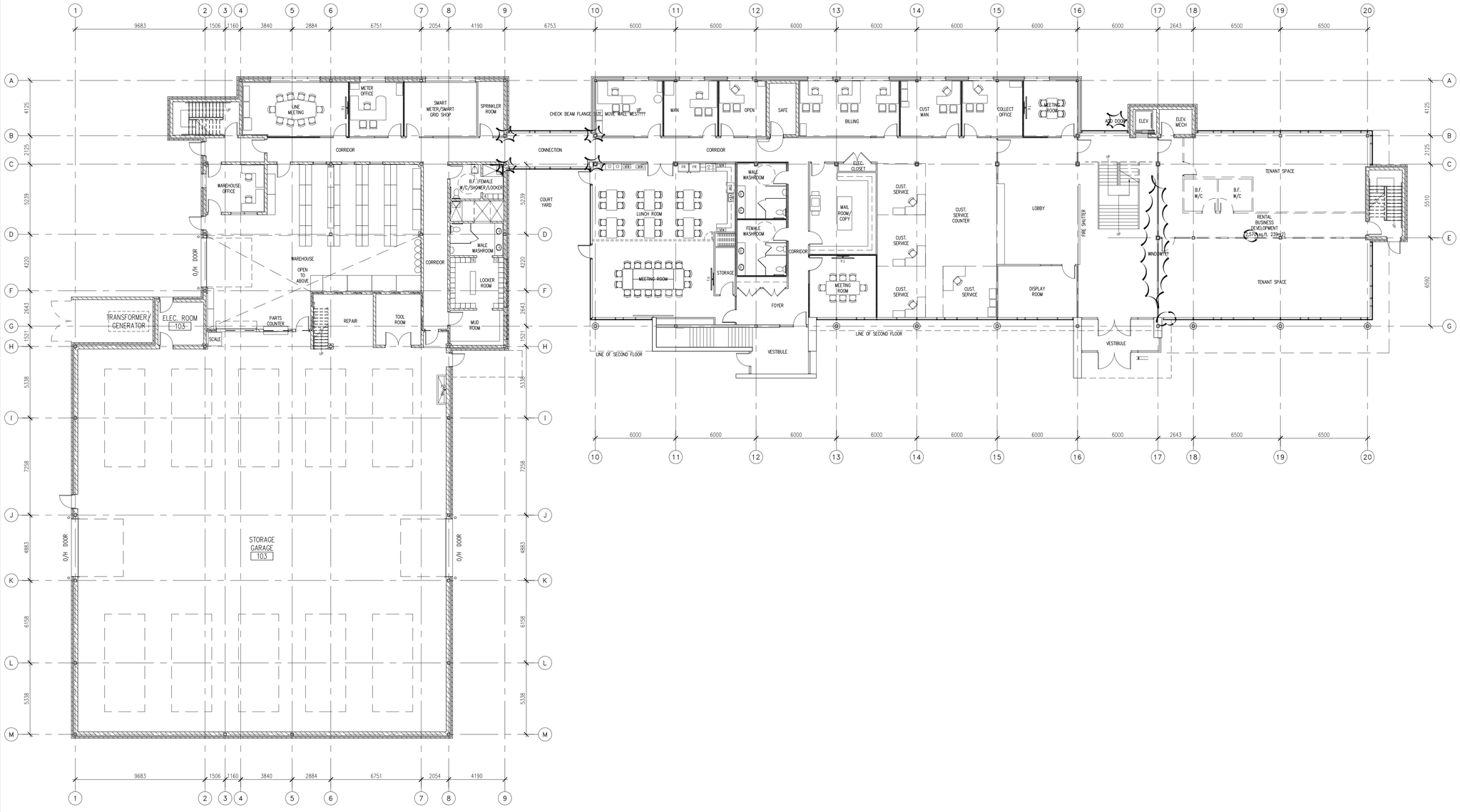
Front View of the Subject Building

Rear View of the Subject Building

APPENDIX 4

FLOOR PLAN

1ST FLOOR



1 / A2.3 MAIN FLOOR PLAN
SCALE: 1:150

No.		DATE

REVISIONS

ALL DIMENSIONS TO BE CHECKED & VERIFIED ON SITE. DISCREPANCIES TO BE REPORTED TO ARCHITECT. LATEST APPROVED DRAWINGS ONLY TO BE USED FOR CONSTRUCTION.

N
PROJECT NORTH

67 High Street,
Barrie, ON. L4N 1W5
PHONE: 705.722.6739
FAX: 705.726.5418

MCL
McKNIGHT CHARRON LAURIN INC. ARCHITECTS

DRAWING TITLE:
MAIN FLOOR PLAN

PROJECT NAME:
INNISFIL HYDRO – NEW FACILITY

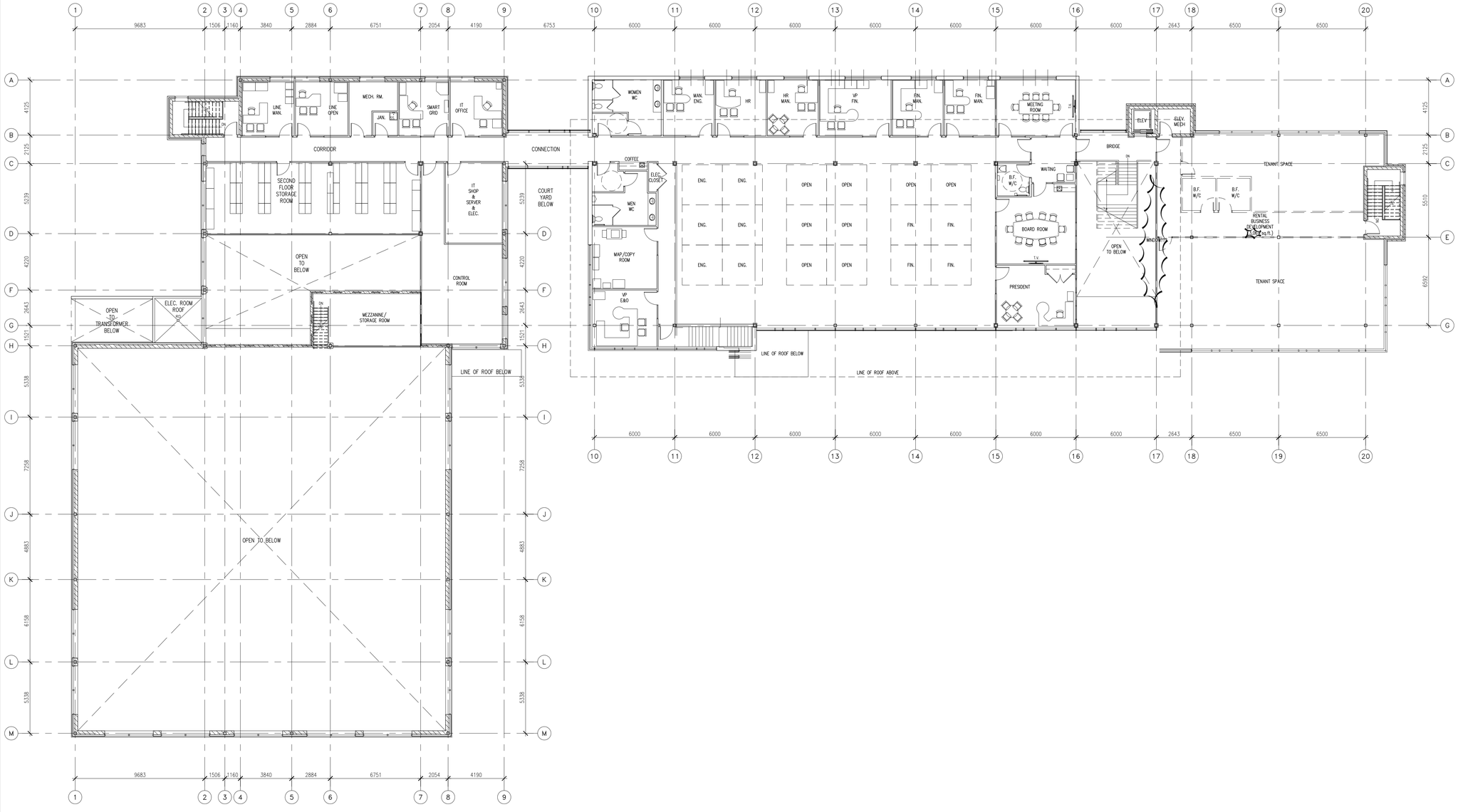
OWNER:
TOWN OF INNISFIL
2101 INNISFIL BEACH ROAD, INNISFIL, ON, L9S 1A1

DATE:	06/12/12	JOB NO.	SHEET NO.
DRAWN BY:	JL	11–045	A2.3
SCALE:	1:150		

APPENDIX 5

FLOOR PLAN

2ND FLOOR



1 / A2.3 SECOND FLOOR PLAN
SCALE: 1:150

No.		DATE

REVISIONS

ALL DIMENSIONS TO BE CHECKED & VERIFIED ON SITE. DISCREPANCIES TO BE REPORTED TO ARCHITECT. LATEST APPROVED DRAWINGS ONLY TO BE USED FOR CONSTRUCTION.

67 High Street,
Barrie, ON. L4N 1W5
PHONE: 705.722.6739
FAX: 705.726.5418

MCL
McKNIGHT CHARRON LAURIN INC.
ARCHITECTS

DRAWING TITLE:
SECOND FLOOR PLAN

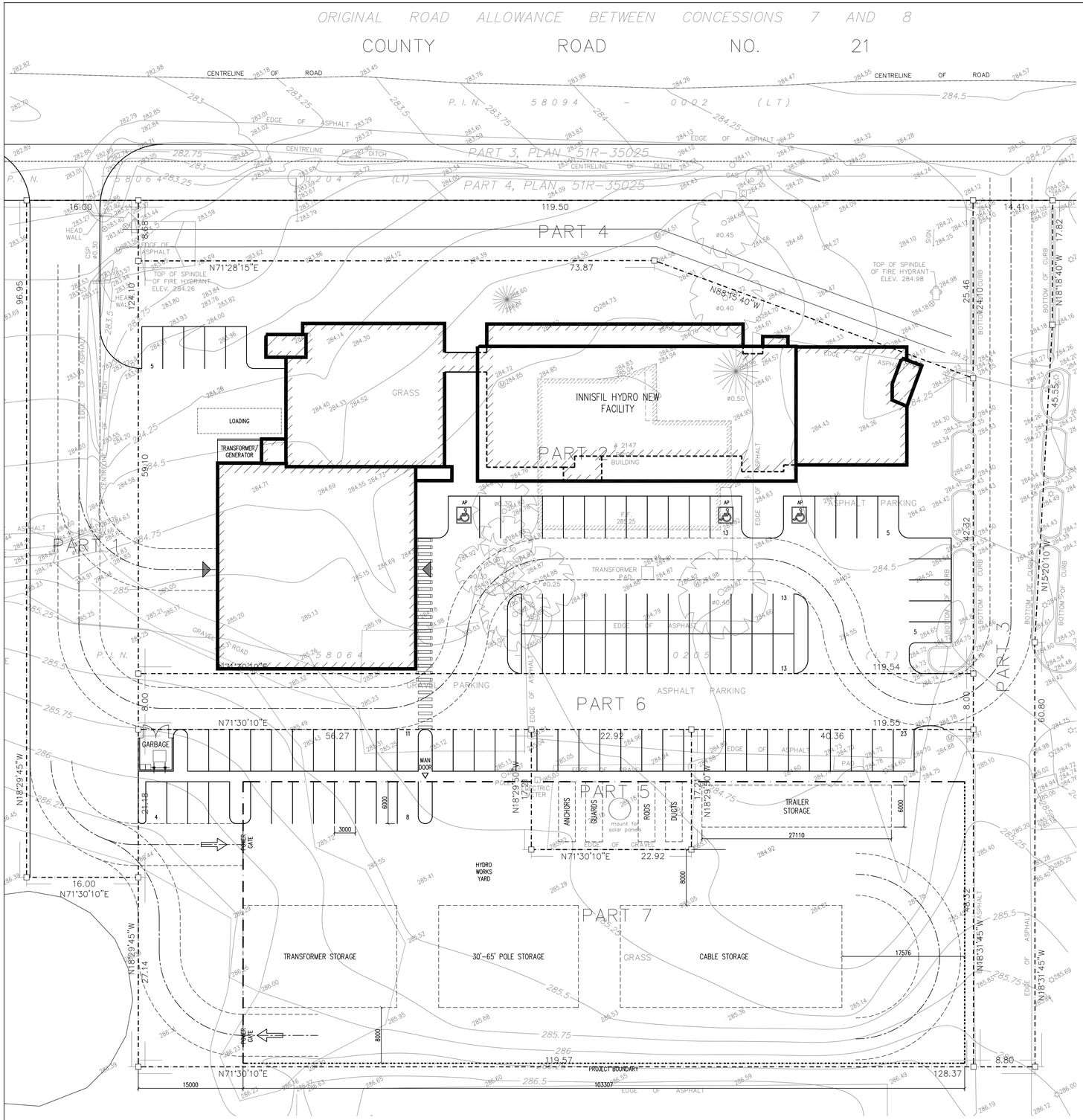
PROJECT NAME:
INNISFIL HYDRO – NEW FACILITY

OWNER:
TOWN OF INNISFIL
2101 INNISFIL BEACH ROAD, INNISFIL, ON, L9S 1A1

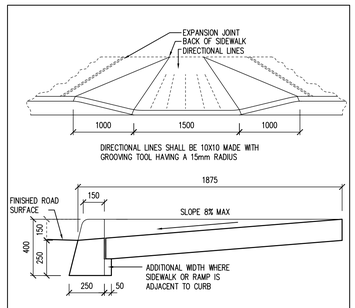
DATE:	06/12/12	JOB NO.	SHEET NO.
DRAWN BY:	JL	11–045	A2.3
SCALE:	1:150		

APPENDIX 6

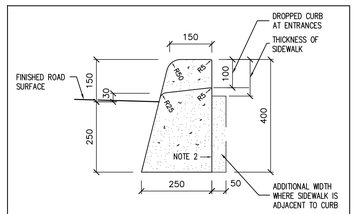
SITE PLAN



1 A1.1 SITE PLAN
SCALE: 1:300

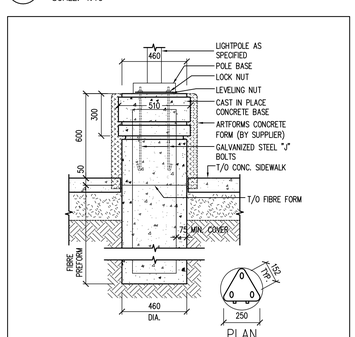


2 A1.1 CURB CUT DETAIL
SCALE: 1:20

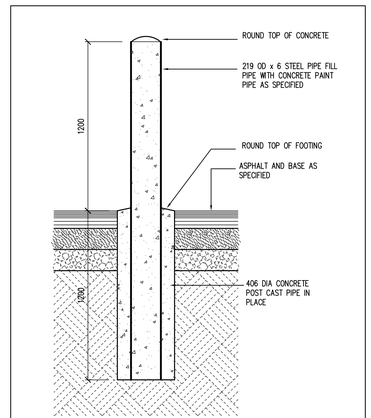


NOTES:
1 WHERE SIDEWALK IS CONTINUOUSLY ADJACENT, REDUCE THE DROPPED CURB AT ENTRANCES TO 75MM.
2 FOR SLIPFORMING PROCEDURE, A 5% BATTER IS ACCEPTABLE.
A TREATMENT AT ENTRANCES SHALL BE ACCORDING TO OPSD 351.010.
B OUTLET TREATMENT SHALL BE ACCORDING TO THE OPSD 610 SERIES.
C THE TRANSITION FROM ONE CURB TYPE TO ANOTHER SHALL BE A MINIMUM LENGTH OF 3.0M, EXCEPT IN CONJUNCTION WITH GUIDE RAIL WHERE IT SHALL BE ACCORDING TO THE OPSD 900 SERIES.
D ALL DIMENSIONS ARE IN MILLIMETERS UNLESS OTHERWISE SHOWN.

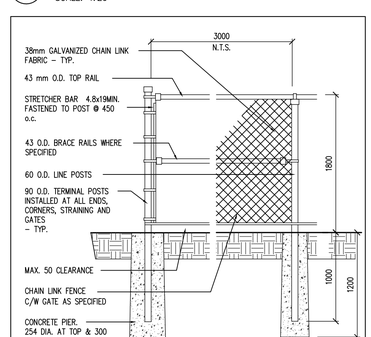
3 A1.1 CURB DETAIL
SCALE: 1:10



4 A1.1 LIGHT STANDARD
SCALE: 1:20



5 A1.1 BOLLARD DETAIL
SCALE: 1:20



6 A1.1 CHAIN LINK FENCE DETAIL
SCALE: 1:20

Firm Name: McKnight Charron Laurin Inc. Architects
67 High Street, Barrie, Ontario
Tel: (705) 722-4739 Fax: (705) 726-5418

Certificate of Practice Number: 4206
The Certificate of Practice Number of the holder is the holder's BCDN.
The Architect noted above has exercised responsible control with respect to design activities. The Architect's seal number is the Architect's BCDN.

Name of Project: INNISFIL HYDRO NEW FACILITY
Location: TOWN OF INNISFIL
2101 INNISFIL BEACH ROAD,
INNISFIL, ONT.
L9S 1A1

Item	Ontario 2006 Building Code Data Matrix Parts 3 & 9			OBC Reference (References are to Division B unless noted [A] for Division A or [C] for Division C.)
1	Project Description	☒ New ☐ Addition ☐ Change Of Use ☐ Alteration	☐ Part 11 / ☐ 11.1 to 11.4	☒ Part 3 [A] / ☐ Part 9 [A] / 9.10.1.3
2	Major Occupancy(s)	GROUP D / GROUP F, DIVISION 2 / GROUP F, DIVISION 3		3.1.2.1.(1) / 9.10.2.
3	Building Area (m sq)	X m sq		1.4.1.2. [A] / 1.4.1.2. [A]
4	Gross Area (m sq)	X m sq		1.4.1.2. [A] / 1.4.1.2. [A]
5	Number Of Storeys	Above Grade: 2 / Below Grade: 0		1.4.1.2. [A] & 3.2.1.1. / 1.4.1.2[A] & 9.10.4
6	Number Of Streets/Fire Fighter Access: 1			3.2.2.10. & 3.2.5. / 9.10.20.
7	Building Classification: GROUP D ×3.2.2.56 / GROUP F2 ×3.2.2.72 / GROUP F3 ×3.2.2.79			3.2.2.20-83 / 9.10.2
8	Sprinkler System Proposed	☒ Entire Building		3.2.2.20-83 / 9.10.8.2
		☐ Selected Compartments		3.2.1.5
		☐ Selected Floor Areas		3.2.2.17
		☐ Basement Only ☐ In Lieu Of Roof Rating		Index / Index
		☐ Not Required		
9	Standpipe Required	☐ Yes ☒ No		3.2.9 / N/A
10	Fire Alarm Required	☒ Yes ☐ No		3.2.4 / 9.10.18
11	Water Service/Supply Is Adequate	☒ Yes ☐ No		3.2.5.7 / N/A
12	High Building	☐ Yes ☒ No		3.2.6 / N/A
13	Construction Restrictions	☐ Combustible ☐ Non-combustible ☒ Both		3.2.2.20-83 / 9.10.6
	Actual Construction	☐ Combustible ☐ Non-combustible ☐ Both		
14	Mezzanine(s) Area (m sq) N/A			3.2.1.1.(3)-(8) / 9.10.4.1
15	Occupant Load Based On	☐ M Sq/person ☒ Design Of Building		3.1.17 / 9.9.1.3
	1st Floor	Occupancy: F2/F3/D Load: 30 Persons		
	2nd Floor	Occupancy: F2/D Load: 35 Persons		
	1st Floor (Rental)	Occupancy: D - 282/9.3 Load: 28 Persons		
	2nd Floor (Rental)	Occupancy: D - 212/9.3 Load: 22 Persons		
16	Barrier-free Design	☒ Yes ☐ No (explain)		3.8 / 9.5.2
17	Hazardous Substances	☐ Yes ☒ No		3.3.1.2 & 3.3.1.19 / 9.10.1.3 (4)
18	Required Fire Resistance Rating (FRR)	Horizontal Assemblies FRR (Hours)	Listed Design No. Or Description (SG-2)	3.2.2.20-83 & 3.2.1.4 / 9.10.8 9.10.9
		Floors: N/A Hours		3.2.2.37
		Roof: N/A Hours		
		Mezzanine: N/A Hours		
		FRR Of Supporting Members	Listed Design No. Or Description (SG-2)	
		Floors: N/A Hours		
		Roof: N/A Hours		
		Mezzanine: N/A Hours		
19	Spatial Separation - Construction Of Exterior Walls			3.2.3 / 9.10.14

Wall	Area Of EBF (m sq)	L.D. (m)	L/H Or H/L	Permitted Max. % Of Openings	Proposed % Of Openings	FRR (Hours)	Listed Design Or Description	Comb. Const	Comb. Constr. Nonc. Cladding	Non-comb. Constr.
North									X	
South									X	
East									X	
West									X	

20 Other - Describe

SITE PLAN LEGEND

- EXISTING SPOT GRADE
- NEW FINISH GRADE
- BH19 BORE HOLE (BH) / TEST PIT (TP)
- HYD. HYDRANT
- V&B VALVE AND BOX
- CB CATCH BASIN
- ENTRY DOOR LOCATION
- H/C PARKING STALL
- B.F. CURB CUT
- S.C. SIAMESE CONNECTION
- FP FLAG POLE
- LIGHT STANDARD
- WALL MOUNTED LIGHT FIXTURE
- CJ CONTROL JOINT
- ASPHALT TYPE 1
- CONCRETE WALKWAY
- FH FIRE HYDRANT
- HP HYDRO POLE
- BD BOLLARD

SIGN POST LEGEND

1. BARRIER FREE PARKING SIGN
2. NO PARKING/FIRE ROUTE SIGN

NOTE: SITE SURVEY INFORMATION TAKEN ON
MAY 15TH 2012
RUDY MAK, SURVEYING LTD.
89 BIG BAY POINT ROAD
BARRIE, ONTARIO L4N 8M5

THIS FACILITY TO MEET THE REQUIREMENTS OF THE OBC AS A POST DISASTER BUILDING.

OBC REFERENCES:

- OBC 3.3.1.20 JAN. ROOMS – NO F.R.R. REQUIRED IF BUILDING SPRINKLERED.
- OBC 3.3.5.6 SECURED/COVERED – STORAGE GARAGE FUNCTION – 1.5 HR. F.R.R. REQUIRED.
- OBC 3.6.2.1 (6) ELECTRICAL EQUIPMENT SERVICE ROOMS – 1 HR. F.R.R. REQUIRED
- OBC 3.6.2.1 (8) SERVICE ROOMS (NO FUEL FIRED HAZARD) – NO F.R.R. REQUIRED

No.		DATE

REVISIONS

ALL DIMENSIONS TO BE CHECKED & VERIFIED ON SITE. DISCREPANCIES TO BE REPORTED TO ARCHITECT. LATEST APPROVED DRAWINGS ONLY TO BE USED FOR CONSTRUCTION.

N
PROJECT NORTH

67 High Street, Barrie,
ON, L4N 1W5
PHONE: 705.722.6739
FAX: 705.726.5418
MCL MCKNIGHT CHARRON LAURIN INC. ARCHITECTS

DRAWING TITLE:
SITE PLAN

PROJECT NAME:
INNISFIL HYDRO – NEW FACILITY

OWNER:
TOWN OF INNISFIL
2101 INNISFIL BEACH ROAD, INNISFIL, ON, L9S 1A1

DATE:	06/12/12	JOB NO.	SHEET NO.
DRAWN BY:	JL	11–045	A1.1
SCALE:	AS SHOWN		

OVERVIEW:

Rate Base Overview:

The rate base used for the purpose of calculating the revenue requirement used in this Application is the average of the balances at the beginning and the end of the 2013 Test Year, plus a working capital allowance, which is 13% of the sum of the cost of power and controllable expenses. The 13% working capital allowance is consistent with the Board's letter of April 12, 2012.

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

IHDSL has provided its rate base calculations for the years 2009 OEB Approved, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and 2013 Test Year in **Table 1** below. IHDSL has calculated its 2013 rate base as **$38,010,954** which will be used to determine the proposed revenue requirement.

Table 2.1 - Summary of Rate Base

Description	2009 OEB Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge CGAAP	2013 Test CGAAP
Gross Fixed Assets	$ 47,925,891	$ 45,430,084	$ 50,156,160	$ 52,269,144	$ 60,194,617	$ 68,814,969
Accumulated Depreciation	$ 26,893,025	$ 25,719,208	$ 27,555,404	$ 27,938,673	$ 29,566,335	$ 31,072,414
Net Book Value	$ 21,032,867	$ 19,710,876	$ 22,600,756	$ 24,330,471	$ 30,628,282	$ 37,742,555
Average Net Book Value	$ 19,436,442	$ 18,584,299	$ 21,155,816	$ 23,410,306	$ 27,386,569	$ 34,147,919
Working Capital	$ 22,890,322	$ 22,604,720	$ 24,323,497	$ 25,744,664	$ 28,943,819	$ 29,715,660
Working Capital Allowance	$ 3,433,548	$ 3,390,708	$ 3,648,525	$ 3,861,700	$ 4,341,573	$ 3,863,036
Rate Base	$ 22,869,990	$ 21,975,007	$ 24,804,341	$ 27,272,005	$ 31,728,141	$ 38,010,954

IHDSL has provided a summary of its calculations of the cost of power and controllable expenses utilized in the calculations for determining working capital for the years 2009 OEB Approved, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and 2013 Test Year in **Table 2** below. Further details of IHDSL's calculation of working capital allowance are provided at Exhibit 2, Tab 4, and Schedule 1.

Table 2.2 - Summary of Working Capital

Description	2009 OEB Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge CGAAP	2013 Test CGAAP
Cost of Power	$ 18,956,982	$ 18,877,111	$ 20,393,170	$ 21,570,056	$ 24,297,062	$ 24,238,088
Operations	$ 778,575	$ 694,257	$ 870,151	$ 947,441	$ 1,159,195	$ 1,423,862
Maintenance	$ 657,080	$ 544,761	$ 436,207	$ 528,872	$ 601,800	$ 713,650
Billing & Collecting	$ 1,010,600	$ 970,447	$ 922,742	$ 925,295	$ 955,500	$ 1,106,020
Community Relations	$ 11,700	$ 10,826.00	$ 9,114.00	$ 17,891.00	$ 18,400.00	$ 23,900.00
Administration & General Expense	$ 1,464,785	$ 1,476,113	$ 1,670,170	$ 1,743,770	$ 1,899,862	$ 2,197,640
Property Taxes	$ 10,600	$ 31,205	$ 21,943	$ 11,339	$ 12,000	$ 12,500
Working Capital	$ 22,890,322	$ 22,604,720	$ 24,323,497	$ 25,744,664	$ 28,943,819	$ 29,715,660

This exhibit will compare historical data with the 2012 Bridge Year and 2013 Test Year. In order to make the comparisons meaningful, all comparisons will be made under CGAAP. Changes to capital spending, working capital, fixed assets and rate base due to the conversion from CGAAP to MIFRS will be discussed in Tab 5 – Conversion to MIFRS, of this exhibit.

Innisfil Hydro Distribution Systems Limited:

IHDSL owns and operates the electricity distribution system in its licensed service area in the Town of Innisfil and South Barrie, serving approximately 17,776 Residential, General Service, and Street Lighting, Sentinel Lighting and Unmetered Scattered Load customers/connections and a municipal population of 34,000.

IHDSL is supplied through the Hydro One distribution system at Voltages of 8.3 kV and 44 kV. Electricity is then distributed through IHDSL's service area of 292 square kilometres over 114

kilometres of underground cable and 607 kilometres of overhead cable and 10,000 poles. IHDSL 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 3,312 transformers.

IHDSL 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.

IHDSL owns and maintains approximately 14,777 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. IHDSL completed the installation of smart meters and TOU billing in July 2011 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.

In managing its distribution system assets, IHDSL's main objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, safety (public and customer), and customer service requirements. This Application incorporates IHDSL's 2013 Capital and Expense Budgets in determining the revenue requirement to bring these plans to fruition. Further information will be provided later in this Application.

Accompanying this Schedule as Appendix A is a copy of IHDSL's "Asset Management Plan" document (referred to as the "AMP"), which sets out IHDSL's processes for determining the necessary distribution system investments to ensure safe, reliable delivery of electricity to its customers.

IHDSL 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, IHDSL provides for maintenance planning for the assets. IHDSL maintenance practices and programs are addressed in the Asset Management Plan ("AMP"), and are discussed in Exhibit 4, Tab 1, and Schedule 1.

Capital Asset Categories

IHDSL's assets fall into two broad categories – The first is ***distribution plant***, which includes assets such as high voltage transformation, MTS and substation buildings, poles, conductor, overhead and underground electricity distribution infrastructure, transformers, meters and substation equipment. The second is ***general plant*** which includes assets such as: office building and service centre; office furniture; transportation equipment; communications technology; computer equipment and software; general equipment; and tools. A more detailed list of distribution and general plant categories can be found in Table 2.6 (Gross Assets) in Exhibit 2, Tab 2, and Schedule 2.

Distribution Plant Capital Projects:

IHDSL's capital budget items include:

- **Customer Demand:**

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

- **Infrastructure Replacement and Betterments**

Projects are completed when assets reach their end of useful life and must be replaced. IHDSL 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 IHDSL Hydro and its shoulder 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 additions or upgrades. 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 IHDSL reliability performance as measured by SAIDI, SAIFI and CAIDI indices. These indices are indicators of the reliability of IHDSL'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 requirements may include, among others, directions from the OEB, the IESO, the Ministry of Energy or the Ministry of Environment. Projects driven by the requirement for elimination of long term load transfers by June 30, 2014 as per section 6.5.3 of the DSC are included in this category. Projects related to the expansion or upgrade of distribution generation assets would also fall into this category.

- **Transformer Stations:**

Transformer Stations are used to transfer power from the transmission system at 115 kV to the distribution system at 27.6 kV. Investments are undertaken to improve or maintain reliability to a large numbers of customers, maintain security and safety at the station, and to meet long range load growth. The Station facilities include power transformers, circuit breakers, switchgear, bus, insulators, power cables, support structures, disconnect switches and ancillary equipment.

- **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, meter upgrades, and the 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 IHDSL 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

IHDSL 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.

IHDSL's practice is to replace vehicles every ten years, subject to kilometers, usage and experience with respect to vehicle reliability.

IHDSL 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.

- **Communications Equipment**

This project pool includes capital expenditures pertaining to the purchase of IHDSL'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 IHDSL employees.

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

The 2012 Bridge and 2013 Test Years' gross asset balances reflect the capital expenditure programs forecast for both years. Analyses of 2009 to 2013 capital programs are described in detail in IHDSL's written evidence at 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 IHDSL. 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

IHDSL 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.

VARIANCE ANALYSIS OF RATE BASE

The following tables provide high level variance analysis of the IHDSL's rate base. Further detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2. Exhibit 2, Tab 2, Schedule 1 – Continuity Statements also provides details. Calculations for the Working Capital Allowance are available in Exhibit 2, Tab 4, Schedule 1.

Table 3.1 - 2009 Approved Rate Base to 2009 Actual

Description	2009 OEB Approved	2009 Actual	Variance
Gross Fixed Assets	$ 47,925,891	$ 45,430,084	-$ 2,495,807
Accumulated Depreciation	$ 26,893,025	$ 25,719,208	-$ 1,173,817
Net Book Value	$ 21,032,867	$ 19,710,876	-$ 1,321,991
Average Net Book Value	$ 19,436,442	$ 18,584,299	-$ 852,143
Working Capital	$ 22,890,322	$ 22,604,720	-$ 285,602
Working Capital Allowance	$ 3,433,548	$ 3,390,708	-$ 42,840
Rate Base	$ 22,869,990	$ 21,975,007	-$ 894,984

2009 Actual

The 2009 actual rate base was –($894,984) lower than approved by the Board. The variance amount was due to forecasted/planned capital jobs rescheduled to later start dates.

Table 3.2 - 2009 Rate Base to 2010 Actual

Description	2009 Actual	2010 Actual	Variance
Gross Fixed Assets	$ 45,430,084	$ 50,156,160	$ 4,726,076
Accumulated Depreciation	$ 25,719,208	$ 27,555,404	$ 1,836,196
Net Book Value	$ 19,710,876	$ 22,600,756	$ 2,889,880
Average Net Book Value	$ 18,584,299	$ 21,155,816	$ 2,571,518
Working Capital	$ 22,604,720	$ 24,323,497	$ 1,718,777
Working Capital Allowance	$ 3,390,708	$ 3,648,525	$ 257,817
Rate Base	$ 21,975,007	$ 24,804,341	$ 2,829,334

2010 Actual

The rate base of $24,804,341 for 2010 was an increase of $2,828,334. This increase is primarily the result of an increase in capital expenditures due to the internalization of IHDSL's line crew and the completion of 2 phases of the municipal urbanization projects in 2010 which were extended from 2009. In summary the 2010 rate base was in line with the 2009 Board approved rate base considering it was the first full year after the approved rates.

Table 3.3 - 2010 Rate Base to 2011 Actual

Description	2010 Actual	2011 Actual	Variance
Gross Fixed Assets	$ 50,156,160	$ 52,269,144	$ 2,112,984
Accumulated Depreciation	$ 27,555,404	$ 27,938,673	$ 383,269
Net Book Value	$ 22,600,756	$ 24,330,471	$ 1,729,715
Average Net Book Value	$ 21,155,816	$ 23,410,306	$ 2,254,490
Working Capital	$ 24,323,497	$ 25,744,664	$ 1,421,167
Working Capital Allowance	$ 3,648,525	$ 3,861,700	$ 213,175
Rate Base	$ 24,804,341	$ 27,272,005	$ 2,467,665

2011 Actual

The rate base of $27,272,005 was an increase of $2,467,665. The increase is due to the final phases of the internalization of IHDSL's line crew (including fleet and tools) and the wrap of the urbanization projects.

Table 3.4 - 2011 Rate Base to 2012 Bridge

Description	2011 Actual	2012 Bridge	Variance
Gross Fixed Assets	$ 52,269,144	$ 60,194,617	$ 7,925,473
Accumulated Depreciation	$ 27,938,673	$ 29,566,335	$ 1,627,662
Net Book Value	$ 24,330,471	$ 30,628,282	$ 6,297,811
Average Net Book Value	$ 23,410,306	$ 27,386,569	$ 3,976,263
Working Capital	$ 25,744,664	$ 28,943,819	$ 3,199,155
Working Capital Allowance	$ 3,861,700	$ 4,341,573	$ 479,873
Rate Base	$ 27,272,005	$ 31,728,141	$ 4,456,136

2012 Bridge

In 2012, rate base is forecast to increase by $4,456,136 from 2011. The average net book value of assets increased due to the smart metering infrastructure into capital from Regulatory Assets. An increased capital requirement for IHDSL's new building facility contributes $2,000,000 to the overall capital costs. As referenced in IHDSL's Introduction to Rate Base and in the Executive Summary in Exhibit 1, construction of IHDSL's Head Office and Operations Centre commences in 2012.

Table 3.5 - 2012 Bridge to 2013 Test

Description	2012 Bridge	2013 Test	Variance
Gross Fixed Assets	$ 60,194,617	$ 64,467,293	$ 4,272,676
Accumulated Depreciation	$ 29,566,335	$ 30,319,374	$ 753,039
Net Book Value	$ 30,628,282	$ 34,147,919	$ 3,519,637
Average Net Book Value	$ 27,386,569	$ 34,147,919	$ 6,761,350
Working Capital	$ 28,943,819	$ 29,715,660	$ 771,841
Working Capital Allowance	$ 4,341,573	$ 3,863,036	-$ 478,537
Rate Base	$ 31,728,141	$ 38,010,954	$ 6,282,813

2012 Bridge to 2013 Test

In 2013, rate base is forecast to increase by $6,282,813 over 2012 Bridge Year. The following factors contribute to the variances. An increased capital requirement for IHDSL's new building facility contributes $5,000,000 to the overall capital costs. The average net book value of assets increased significantly due the additional capital spending in 2013. The removal of stranded meters reduced the average net book value in 2013. The 2013 working capital allowance decreased by -$478,537 from the 2012 Bridge Year due to the reduction of the Working Capital allowance to 13% from 15% in 2012.

In December 2013, IHDSL's Head Office and Operations Centre will be completed and ready for occupancy.

GROSS ASSETS – PROPERTY, PLANT & EQUIPMENT and ACCUMULATED AMORTIZATION:

Continuity Statements

Tables 2.2.1, 2.2.2, 2.2.3 , 2.2.4(a), 2.2.4 (b), 2.2.5(a) and 2.2.5(b) below provide details of the Fixed Asset Continuity Schedules for the years 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and 2013 Test Year under CGAAP. Tables 2.2.4(b) and 2.2.5(b) provide details of the Fixed Asset Continuity Schedules for the 2012 Bridge Year and 2013 Test Year under MIFRS. Table 2.2.6(a) and Table 2.2.6(b) below provides details of Variances of Gross Assets year over year from 2008 Actual through to 2013 Test Year based on Canadian Generally Accepted Accounting Principles (CGAAP) and MIFRS for the 2012 Bridge Year and 2013 Test Year.

IHDSL uses the following accounts and descriptions in the calculations of its net fixed assets:

1805 – Land: This account is used to record the cost of land held by IHDSL, used in connection with distribution.

1806 -Land Rights: This account is used to record the cost of rights, interests, easements and privileges held by the LDC in land owned by others.

1820 - Distribution Station Equipment – Normally 1 Primary below 50 kV : This account is used to record the installed cost of transforming and switching equipment in each of IHDSL's distribution stations, used for the purpose of stepping down to distribution voltages.

1830 -Poles, Towers and Fixtures: This account is used to record the installed cost of poles, towers, and fixtures used for supporting overhead distribution conductors and service wires in accordance with the example items from the Accounting Procedures Handbook issued by the

OEB.

1835 -Overhead Conductors and Devices: This account is used to record the installed cost of overhead conductors and devices used for distribution purposes in accordance with the example items from the Accounting Procedures Handbook issued by the OEB.

1840 -Underground Conduit: This account is used to record the installed cost of underground conduit and tunnels used for housing distribution cables or wires in accordance with the example items from the Accounting Procedures Handbook issued by the OEB.

1845 -Underground Conductors and Devices: This account is used to record the installed cost of underground conductors and devices used for distribution purposes in accordance with the example items from the Accounting Procedures Handbook issued by the OEB.

1850 -Distribution Transformers: This account is used to record the installed cost of overhead and underground distribution line transformers and pole type and underground voltage regulators owned by the utility for use in transforming electricity to the voltage at which it is to be used by the customer in accordance with the example items from the Accounting Procedures Handbook issued by the OEB.

1855 -Services: This account is used to record the installed cost of overhead and underground conductors leading from a point where wires leave the last pole of the overhead system of the transformers, or manhole, or the top of the pole of the distribution line to the point of connection with the customers' electrical panel, in accordance with the example items from the Accounting Procedures Handbook issued by the OEB.

1860 -Meters: This account is used to record the installed cost of traditional meters or devices for use in measuring the electricity delivered to its users. (including Smart Meters).

1908 -Buildings and Fixtures: This account includes the costs of buildings and fixtures used for

utility purposes owned by IHDSL.

1915 – Office Furniture & Equipment: This account contains the cost of general office furniture and equipment.

1920 – Computer Equipment -Hardware: This account includes costs of all computer hardware purchased. Hardware is inclusive of all physical equipment associated with input, processing, storage, and output functions, also word processing equipment.

1925 – Computer Software: This account contains the installed costs of all computer software purchased or developed in house.

1930 – Transportation Equipment: This account contains the costs of all vehicles owned by IHDSL including automobiles, small trucks, truck chassis, special truck bodies, and other mobile equipment. The items in this account are considered unique and identifiable assets.

1935 – Stores Equipment: This account includes the cost of equipment used in IHDSL's warehouse for shipping, receiving, handling and storage of materials and supplies.

1940 – Tools, Shop and Garage Equipment: This account contains the cost of all tools and non-power equipment purchased by IHDSL in accordance with the example items from the Accounting Procedures Handbook (APH) issued by the OEB.

1945 – Measurement and Testing Equipment: This account contains the cost of all measurement and testing equipment purchased by Midland PUC in accordance with the example items from the Accounting Procedures Handbook (APH) issued by the OEB.

1955 – Communications Equipment: This account includes amounts relating to telephone and wireless equipment for the general use in connection with utility operations.

1960 – Miscellaneous Equipment: This account includes amounts relating to equipment, apparatus, etc. used in the LDC operations which are not included in other accounts.

1980 – System Supervisory Equipment: This account includes amounts relating to control equipment used for the purposes of remote operation and control of utility transformer stations and distribution equipment.

1995 – Contributions and Grants: This account includes amounts relating to contribution or grants in cash, services or property from government or government agencies, corporation, individuals and others who received in aid of construction or for acquisition of fixed assets (contributed capital.)

CONVERSION TO MODIFIED INTERNATIONAL REPORTING STANDARDS

The conversion from Canadian Generally Accepted Accounting Principles (CGAAP) to Modified International Financial Reporting Standards (MIFRS) has resulted in some changes to IHDSL's accounting for Property Plant and Equipment (PP&E).

IHDSL has elected to take the IFRS 1 Exemption for rate regulated entities, which allows for the use of the net book value of assets as at the date of transition as the deemed cost of the asset. This change has been reflected in the continuity statements provided below for the 2012 Bridge Year and 2013 Test Year.

COMPONENTIZATION AND AMORTIZATION

IAS 16 requires each part of an item of PP&E with a cost that is significant in relation to the total cost to be depreciated separately. In addition IAS 16 requires that entities perform a review of its useful lives, amortization methods and residual values on an annual basis.

IHDSL has reviewed the useful lives of its assets with the aid of the Kinectrics Report K-418033-RA-001-R000, entitled "Asset Depreciation Study for the Ontario Energy Board", dated July 8th, 2010. IHDSL has restated its continuity statements for the 2012 Bridge year and 2013 Test year to include these changes. These changes are presented under the MIFRS schedules below.

IAS 16 – Property, Plant and Equipment – Measurement after Recognition.

For subsequent periods following the initial recognition of an asset, IAS 16 permits the choice of using either the Cost Model or the Revaluation Model for valuing PP&E. IHDSL will continue to use the Cost Model to measure PP&E.

Table 2.1: Fixed Asset Continuity Schedule - 2009

Appendix 2-B
Fixed Asset Continuity Schedule

Year **2009**

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 855,124	$ 129,940		$ 985,064	-$ 687,862	-$ 113,942		-$ 801,804	$ 183,260
CEC	1612	Land Rights (Formally known as Account 1906)					$ -				$ -	$ -
N/A	1805	Land		$ 282,031		-$ 8,261	$ 273,770				$ -	$ 273,770
CEC	1806	Land Rights		$ 965,425	$ 11,122		$ 976,547	-$ 512,797	-$ 14,883		-$ 527,680	$ 448,867
47	1808	Buildings					$ -				$ -	$ -
13	1810	Leasehold Improvements		$ 86,252			$ 86,252	-$ 24,150	-$ 3,450		-$ 27,600	$ 58,652
47	1815	Transformer Station Equipment >50 kV					$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 4,297,046	$ 91,039		$ 4,388,085	-$ 2,146,513	-$ 142,270		-$ 2,288,783	$ 2,099,302
47	1825	Storage Battery Equipment					$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 6,727,068	$ 792,949		$ 7,520,017	-$ 3,423,845	-$ 287,398		-$ 3,711,243	$ 3,808,774
47	1835	Overhead Conductors & Devices		$ 9,716,063	$ 1,549,227		$ 11,265,290	-$ 6,561,447	-$ 418,334		-$ 6,979,781	$ 4,285,509
47	1840	Underground Conduit		$ 1,771,982	$ 11,848		$ 1,783,830	-$ 268,045	-$ 70,964		-$ 339,009	$ 1,444,821
47	1845	Underground Conductors & Devices		$ 5,931,254	$ 1,795,662		$ 7,726,916	-$ 3,219,011	-$ 272,619		-$ 3,491,630	$ 4,235,286
47	1850	Line Transformers		$ 7,595,912	$ 247,676		$ 7,843,588	-$ 4,645,272	-$ 300,997		-$ 4,946,269	$ 2,897,319
47	1855	Services (Overhead & Underground)		$ 3,402,937	$ 167,287		$ 3,570,224	-$ 1,317,615	-$ 139,481		-$ 1,457,096	$ 2,113,128
47	1860	Meters		$ 1,878,437	$ 71,174	-$ 1,270,515	$ 679,096	-$ 1,214,152	-$ 64,321	$ 1,068,808	-$ 209,665	$ 469,431
47	1860	Meters (Smart Meters)					$ -				$ -	$ -
47	1875	Street Lighting		$ 7,646			$ 7,646	-$ 1,755	-$ 305		-$ 2,060	$ 5,586
N/A	1905	Land		$ 201,049			$ 201,049				$ -	$ 201,049
47	1908	Buildings & Fixtures		$ 699,797	$ 3,151		$ 702,948	-$ 187,636	-$ 27,933		-$ 215,569	$ 487,379
13	1910	Leasehold Improvements					$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 258,797	$ 14,296		$ 273,093	-$ 192,103	-$ 12,053		-$ 204,156	$ 68,937
8	1915	Office Furniture & Equipment (5 years)					$ -				$ -	$ -
10	1920	Computer Equipment - Hardware		$ 753,908	$ 53,941		$ 807,849	-$ 591,155	-$ 60,219		-$ 651,374	$ 156,475
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)					$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)					$ -				$ -	$ -
10	1930	Transportation Equipment		$ 370,171	$ 83,273	-$ 210,930	$ 242,514	-$ 307,866	-$ 28,689	$ 210,930	-$ 125,625	$ 116,889
8	1935	Stores Equipment		$ 19,404	$ 6,953		$ 26,357	-$ 13,303	-$ 1,192		-$ 14,495	$ 11,862
8	1940	Tools, Shop & Garage Equipment		$ 159,103	$ 6,190		$ 165,293	-$ 134,338	-$ 3,666		-$ 138,004	$ 27,289
8	1945	Measurement & Testing Equipment		$ 17,029	$ 6,064		$ 23,093	-$ 7,431	-$ 2,006		-$ 9,437	$ 13,656
8	1950	Power Operated Equipment					$ -				$ -	$ -
8	1955	Communications Equipment					$ -				$ -	$ -
8	1955	Communication Equipment (Smart Meters)					$ -				$ -	$ -
8	1960	Miscellaneous Equipment					$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises					$ -				$ -	$ -
47	1980	System Supervisor Equipment		$ 1,177,189	$ 95,676		$ 1,272,865	-$ 529,872	-$ 81,593		-$ 611,465	$ 661,400
47	1985	Miscellaneous Fixed Assets					$ -				$ -	$ -
47	1995	Contributions & Grants		-$ 4,566,109	-$ 825,193		-$ 5,391,302	$ 836,374	$ 197,163		$ 1,033,537	-$ 4,357,765
	etc.						$ -				$ -	$ -
		Total		**$ 42,607,515**	**$ 4,312,275**	**-$ 1,489,706**	**$ 45,430,084**	**-$ 25,149,794**	**-$ 1,849,152**	**$ 1,279,738**	**-$ 25,719,208**	**$ 19,710,876**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 1,849,152

Table 2.3: Fixed Asset Continuity Schedule - 2010

Appendix 2-B

Fixed Asset Continuity Schedule

Year 2010

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 985,064	$ 47,687		$ 1,032,751	-$ 801,804	-$ 102,531		-$ 904,335	$ 128,416
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ 273,770			$ 273,770	$ -			$ -	$ 273,770
CEC	1806	Land Rights		$ 976,547	$ 11,917		$ 988,464	-$ 527,680	-$ 15,130		-$ 542,810	$ 445,654
47	1808	Buildings		$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ 86,252			$ 86,252	-$ 27,600	-$ 3,450		-$ 31,050	$ 55,202
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 4,388,085	$ 43,198		$ 4,431,283	-$ 2,288,783	-$ 124,522		-$ 2,413,305	$ 2,017,978
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 7,520,017	$ 811,713		$ 8,331,730	-$ 3,711,243	-$ 319,524		-$ 4,030,767	$ 4,300,963
47	1835	Overhead Conductors & Devices		$ 11,265,290	$ 736,529		$ 12,001,819	-$ 6,979,781	-$ 463,964		-$ 7,443,745	$ 4,558,074
47	1840	Underground Conduit		$ 1,783,830	$ 26,610		$ 1,810,440	-$ 339,009	-$ 72,373		-$ 411,382	$ 1,399,058
47	1845	Underground Conductors & Devices		$ 7,726,916	$ 3,834,252		$ 11,561,168	-$ 3,491,630	-$ 384,602		-$ 3,876,232	$ 7,684,936
47	1850	Line Transformers		$ 7,843,588	$ 291,950		$ 8,135,538	-$ 4,946,269	-$ 314,223		-$ 5,260,492	$ 2,875,046
47	1855	Services (Overhead & Underground)		$ 3,570,224	$ 141,283		$ 3,711,507	-$ 1,457,096	-$ 145,653		-$ 1,602,749	$ 2,108,758
47	1860	Meters		$ 679,096		-$ 492,071	$ 187,025	-$ 209,665	-$ 22,721	$ 192,417	-$ 39,969	$ 147,056
47	1860	Meters (Smart Meters)		$ -			$ -	$ -			$ -	$ -
47	1875	Street Lighting		$ 7,646			$ 7,646	-$ 2,060	-$ 305		-$ 2,365	$ 5,281
N/A	1905	Land		$ 201,049			$ 201,049	$ -			$ -	$ 201,049
47	1908	Buildings & Fixtures		$ 702,948	$ 34,836		$ 737,784	-$ 215,569	-$ 28,795		-$ 244,364	$ 493,420
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 273,093	$ 21,306		$ 294,399	-$ 204,156	-$ 13,478		-$ 217,634	$ 76,765
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 807,849	$ 64,210		$ 872,059	-$ 651,374	-$ 63,093		-$ 714,467	$ 157,592
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 242,514	$ 594,402		$ 836,916	-$ 125,625	-$ 90,655		-$ 216,280	$ 620,636
8	1935	Stores Equipment		$ 26,357	$ 3,761		$ 30,118	-$ 14,495	-$ 1,728		-$ 16,223	$ 13,895
8	1940	Tools, Shop & Garage Equipment		$ 165,293	$ 304,092		$ 469,385	-$ 138,004	-$ 19,064		-$ 157,068	$ 312,317
8	1945	Measurement & Testing Equipment		$ 23,093	$ 597		$ 23,690	-$ 9,437	-$ 2,339		-$ 11,776	$ 11,914
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ 1,272,865	$ 52,041		$ 1,324,906	-$ 611,465	-$ 86,517		-$ 697,982	$ 626,924
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 5,391,302	-$ 1,802,237		-$ 7,193,539	$ 1,033,537	$ 246,054		$ 1,279,591	-$ 5,913,948
	etc.			$ -			$ -				$ -	$ -
				$ -								
		Total		**$ 45,430,084**	**$ 5,218,147**	**-$ 492,071**	**$ 50,156,160**	**-$ 25,719,208**	**-$ 2,028,613**	**$ 192,417**	**-$ 27,555,404**	**$ 22,600,756**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 90,655
Stranded meters	$ 27,337
Net Depreciation	-$ 1,965,295

Table 2.4: Fixed Asset Continuity Schedule – 2011

Appendix 2-B
Fixed Asset Continuity Schedule

Year 2011

CCA Class	OEB	Description	Depreciation Rate	Cost Opening Balance	Cost Additions	Cost Disposals	Cost Closing Balance	Accumulated Depreciation Opening Balance	Accumulated Depreciation Additions	Accumulated Depreciation Disposals	Accumulated Depreciation Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 1,032,751	$ 73,245	-$ 774,930	$ 331,066	-$ 904,335	-$ 81,963	$ 774,427	-$ 211,871	$ 119,195
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ 273,770			$ 273,770	$ -			$ -	$ 273,770
CEC	1806	Land Rights		$ 988,464	$ 1,981	-$ 7,742	$ 982,703	-$ 542,810	-$ 15,176		-$ 557,986	$ 424,717
47	1808	Buildings		$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ 86,252			$ 86,252	-$ 31,050	-$ 3,450		-$ 34,500	$ 51,752
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 4,431,283	$ 152,331	-$ 225,053	$ 4,358,561	-$ 2,413,305	-$ 125,218	$ 215,647	-$ 2,322,876	$ 2,035,685
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 8,331,730	$ 935,010	-$ 188,852	$ 9,077,888	-$ 4,030,767	-$ 347,982	$ 92,096	-$ 4,286,653	$ 4,791,235
47	1835	Overhead Conductors & Devices		$ 12,001,819	$ 1,491,019	-$ 299,892	$ 13,192,946	-$ 7,443,745	-$ 289,141	$ 255,965	-$ 7,476,921	$ 5,716,025
47	1840	Underground Conduit		$ 1,810,440	$ 225,131		$ 2,035,571	-$ 411,382	-$ 72,418	-$ 3,967	-$ 487,767	$ 1,547,804
47	1845	Underground Conductors & Devices		$ 11,561,168	$ 251,455	-$ 91,467	$ 11,721,156	-$ 3,876,232	-$ 465,614	$ 2,830	-$ 4,339,016	$ 7,382,140
47	1850	Line Transformers		$ 8,135,538	$ 487,484	-$ 20,236	$ 8,602,786	-$ 5,260,492	-$ 333,051	$ 5,597	-$ 5,587,946	$ 3,014,840
47	1855	Services (Overhead & Underground)		$ 3,711,507	$ 306,192	-$ 563	$ 4,017,136	-$ 1,602,749	-$ 154,495	$ 64	-$ 1,757,180	$ 2,259,956
47	1860	Meters		$ 187,025	$ 10,308	$ 89,925	$ 287,258	-$ 39,969	-$ 27,067		-$ 67,036	$ 220,222
47	1860	Meters (Smart Meters)		$ -			$ -	$ -			$ -	$ -
47	1875	Street Lighting		$ 7,646			$ 7,646	-$ 2,365	-$ 305		-$ 2,670	$ 4,976
N/A	1905	Land		$ 201,049			$ 201,049	$ -			$ -	$ 201,049
47	1908	Buildings & Fixtures		$ 737,784	$ 1,847		$ 739,631	-$ 244,364	-$ 29,548		-$ 273,912	$ 465,719
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 294,399	$ 14,256		$ 308,655	-$ 217,634	-$ 15,014		-$ 232,648	$ 76,007
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 872,059	$ 16,388	-$ 373,141	$ 515,306	-$ 714,467	-$ 63,019	$ 377,405	-$ 400,081	$ 115,225
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 836,916	$ 297,131	$ 40,149	$ 1,174,196	-$ 216,280	-$ 220,718	-$ 23,136	-$ 460,134	$ 714,062
8	1935	Stores Equipment		$ 30,118	$ 1,706		$ 31,824	-$ 16,223	-$ 1,949		-$ 18,172	$ 13,652
8	1940	Tools, Shop & Garage Equipment		$ 469,385	$ 58,448	-$ 40,149	$ 487,684	-$ 157,068	-$ 34,180	$ 3,011	-$ 188,237	$ 299,447
8	1945	Measurement & Testing Equipment		$ 23,690	$ 9,307		$ 32,997	-$ 11,776	-$ 2,450		-$ 14,226	$ 18,771
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ 1,324,906	$ 82,487		$ 1,407,393	-$ 697,982	-$ 91,077		-$ 789,059	$ 618,334
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 7,193,539	-$ 521,407		-$ 7,714,946	$ 1,279,591	$ 290,627		$ 1,570,218	-$ 6,144,728
	etc.			$ -			$ -				$ -	$ -
				$ -								
		Total		**$ 50,156,160**	**$ 3,894,319**	**-$ 1,891,951**	**$ 52,158,528**	**-$ 27,555,404**	**-$ 2,083,208**	**$ 1,699,939**	**-$ 27,938,673**	**$ 24,219,855**
												$ 24,330,471
		Smart Meter Trueup										
10		Smart meters			$ 2,162,281				-$ 327,495			
8		Computer software			$ 32,533				-$ 27,111			

Less: *Fully Allocated Depreciation*

Transportation	-$ 220,718
Stores Equipment	$ 31,745
Net Depreciation	-$ 1,894,235

Notes:

Table 2.5: Fixed Asset Continuity Schedule – 2012 (CGAAP)

Appendix 2-B
Fixed Asset Continuity Schedule

Year **2012**

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 363,599	$ 282,150		$ 645,749	-$ 238,982	-$ 113,920		-$ 352,902	$ 292,847
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ 273,770	$ 465,000		$ 738,770	$ -			$ -	$ 738,770
CEC	1806	Land Rights		$ 982,703			$ 982,703	-$ 557,986	-$ 14,872		-$ 572,858	$ 409,845
47	1808	Buildings		$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ 86,252			$ 86,252	-$ 34,500	-$ 3,312		-$ 37,812	$ 48,440
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 4,358,561	$ 35,448		$ 4,394,009	-$ 2,322,876	-$ 120,918		-$ 2,443,794	$ 1,950,215
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 9,077,888	$ 1,172,023	-$ 100,000	$ 10,149,911	-$ 4,286,653	-$ 357,503	$ 85,000	-$ 4,559,156	$ 5,590,755
47	1835	Overhead Conductors & Devices		$ 13,192,946	$ 1,314,249	-$ 150,000	$ 14,357,195	-$ 7,476,921	-$ 303,860	$ 127,500	-$ 7,653,281	$ 6,703,914
47	1840	Underground Conduit		$ 2,035,571	$ 37,200		$ 2,072,771	-$ 487,767	-$ 70,265		-$ 558,032	$ 1,514,739
47	1845	Underground Conductors & Devices		$ 11,721,156	$ 454,700	-$ 50,000	$ 12,125,856	-$ 4,339,016	-$ 456,084	$ 42,500	-$ 4,752,600	$ 7,373,256
47	1850	Line Transformers		$ 8,602,786	$ 545,110	-$ 10,000	$ 9,137,896	-$ 5,587,946	-$ 330,631	$ 8,500	-$ 5,910,077	$ 3,227,819
47	1855	Services (Overhead & Underground)		$ 4,017,136	$ 207,405		$ 4,224,541	-$ 1,757,180	-$ 152,463		-$ 1,909,643	$ 2,314,898
47	1860	Meters		$ 287,258			$ 287,258	-$ 67,036	-$ 11,490		-$ 78,526	$ 208,732
47	1860	Meters (Smart Meters)		$ 2,162,281	$ 74,240		$ 2,236,521	-$ 327,495	-$ 146,622		-$ 474,117	$ 1,762,404
47	1875	Street Lighting		$ 7,646		-$ 7,646	$ -	-$ 2,670		$ 2,670	$ -	$ -
N/A	1905	Land		$ 201,049			$ 201,049	$ -			$ -	$ 201,049
47	1908	Buildings & Fixtures		$ 739,631	$ 2,025,000		$ 2,764,631	-$ 273,912	-$ 28,866		-$ 302,778	$ 2,461,853
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 308,655	$ 25,500		$ 334,155	-$ 232,648	-$ 12,536		-$ 245,184	$ 88,971
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 515,306	$ 122,500		$ 637,806	-$ 400,081	-$ 62,665		-$ 462,746	$ 175,060
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 1,174,196			$ 1,174,196	-$ 460,134	-$ 159,800		-$ 619,934	$ 554,262
8	1935	Stores Equipment		$ 31,824	$ 4,000		$ 35,824	-$ 18,172	-$ 1,954		-$ 20,126	$ 15,698
8	1940	Tools, Shop & Garage Equipment		$ 487,684	$ 27,000		$ 514,684	-$ 188,237	-$ 32,112		-$ 220,349	$ 294,335
8	1945	Measurement & Testing Equipment		$ 32,997	$ 8,500		$ 41,497	-$ 14,226	-$ 2,631		-$ 16,857	$ 24,640
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ 1,407,393	$ 367,850		$ 1,775,243	-$ 789,059	-$ 97,267		-$ 886,326	$ 888,917
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 7,714,946	-$ 1,083,954		-$ 8,798,900	$ 1,570,218	$ 300,681		$ 1,870,899	-$ 6,928,001
	etc.			$ -			$ -				$ -	$ -
				$ -								
		Total		**$ 54,353,342**	**$ 6,083,921**	**-$ 317,646**	**$ 60,119,617**	**-$ 28,293,279**	**-$ 2,179,090**	**$ 266,170**	**-$ 30,206,199**	**$ 29,913,418**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 159,800
Stranded Meters	$ 43,000
Net Depreciation	-$ 2,062,290

Table 2.6: Fixed Asset Continuity Statement – 2012 (MIFRS)

Appendix 2-B
Fixed Asset Continuity Schedule

Year **2012**

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 363,599	$ 282,150		$ 645,749	-$ 238,982	-$ 113,920		-$ 352,902	$ 292,847
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ 273,770	$ 465,000		$ 738,770	$ -			$ -	$ 738,770
CEC	1806	Land Rights		$ 982,703			$ 982,703	-$ 557,986	-$ 14,872		-$ 572,858	$ 409,845
47	1808	Buildings		$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ 86,252			$ 86,252	-$ 34,500	-$ 3,312		-$ 37,812	$ 48,440
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 4,358,561	$ 35,448		$ 4,394,009	-$ 2,322,876	-$ 90,878		-$ 2,413,754	$ 1,980,255
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 9,077,888	$ 1,172,023	-$ 100,000	$ 10,149,911	-$ 4,286,653	-$ 187,013	$ 85,000	-$ 4,388,666	$ 5,761,245
47	1835	Overhead Conductors & Devices		$ 13,192,946	$ 1,314,249	-$ 150,000	$ 14,357,195	-$ 7,476,921	-$ 147,438	$ 127,500	-$ 7,496,859	$ 6,860,336
47	1840	Underground Conduit		$ 2,035,571	$ 37,200		$ 2,072,771	-$ 487,767	-$ 48,744		-$ 536,511	$ 1,536,260
47	1845	Underground Conductors & Devices		$ 11,721,156	$ 454,700	-$ 50,000	$ 12,125,856	-$ 4,339,016	-$ 316,093	$ 42,500	-$ 4,612,609	$ 7,513,247
47	1850	Line Transformers		$ 8,602,786	$ 545,110	-$ 10,000	$ 9,137,896	-$ 5,587,946	-$ 206,644	$ 8,500	-$ 5,786,090	$ 3,351,806
47	1855	Services (Overhead & Underground)		$ 4,017,136	$ 207,405		$ 4,224,541	-$ 1,757,180	-$ 79,751		-$ 1,836,931	$ 2,387,610
47	1860	Meters		$ 287,258			$ 287,258	-$ 67,036	-$ 11,490		-$ 78,526	$ 208,732
47	1860	Meters (Smart Meters)		$ 2,162,281	$ 74,240		$ 2,236,521	-$ 327,495	-$ 146,622		-$ 474,117	$ 1,762,404
47	1875	Street Lighting		$ 7,646		-$ 7,646	$ -	-$ 2,670		$ 2,670	$ -	$ -
N/A	1905	Land		$ 201,049			$ 201,049	$ -			$ -	$ 201,049
47	1908	Buildings & Fixtures		$ 739,631	$ 2,025,000		$ 2,764,631	-$ 273,912	-$ 28,866		-$ 302,778	$ 2,461,853
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 308,655	$ 25,500		$ 334,155	-$ 232,648	-$ 12,536		-$ 245,184	$ 88,971
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 515,306	$ 122,500		$ 637,806	-$ 400,081	-$ 62,665		-$ 462,746	$ 175,060
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 1,174,196			$ 1,174,196	-$ 460,134	-$ 159,800		-$ 619,934	$ 554,262
8	1935	Stores Equipment		$ 31,824	$ 4,000		$ 35,824	-$ 18,172	-$ 1,954		-$ 20,126	$ 15,698
8	1940	Tools, Shop & Garage Equipment		$ 487,684	$ 27,000		$ 514,684	-$ 188,237	-$ 32,112		-$ 220,349	$ 294,335
8	1945	Measurement & Testing Equipment		$ 32,997	$ 8,500		$ 41,497	-$ 14,226	-$ 2,631		-$ 16,857	$ 24,640
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ 1,407,393	$ 367,850		$ 1,775,243	-$ 789,059	-$ 97,267		-$ 886,326	$ 888,917
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 7,714,946	-$ 1,083,954		-$ 8,798,900	$ 1,570,218	$ 225,382		$ 1,795,600	-$ 7,003,300
	etc.			$ -			$ -				$ -	$ -
				$ -								
		Total		**$ 54,353,342**	**$ 6,083,921**	**-$ 317,646**	**$ 60,119,617**	**-$ 28,293,279**	**-$ 1,539,226**	**$ 266,170**	**-$ 29,566,335**	**$ 30,553,282**
												$ 30,628,282

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 159,800
Stranded Meters	$ 43,000
Net Depreciation	-$ 1,422,426

Table 2.6: Fixed Asset Continuity Statement – 2013 (MIFRS)

Appendix 2-B
Fixed Asset Continuity Schedule

Year **2013**

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 645,749	$ 278,500		$ 924,249	-$ 352,902	-$ 174,811		-$ 527,713	$ 396,536
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ 738,770			$ 738,770	$ -			$ -	$ 738,770
CEC	1806	Land Rights		$ 982,703			$ 982,703	-$ 572,858	-$ 14,575		-$ 587,433	$ 395,270
47	1808	Buildings		$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ 86,252			$ 86,252	-$ 37,812	-$ 3,312		-$ 41,124	$ 45,128
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 4,394,009	$ 194,422		$ 4,588,431	-$ 2,413,754	-$ 93,752		-$ 2,507,506	$ 2,080,925
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 10,149,911	$ 918,153	-$ 105,000	$ 10,963,064	-$ 4,388,666	-$ 210,238	$ 89,250	-$ 4,509,654	$ 6,453,410
47	1835	Overhead Conductors & Devices		$ 14,357,195	$ 1,123,543	-$ 157,500	$ 15,323,238	-$ 7,496,859	-$ 167,753	$ 133,875	-$ 7,530,737	$ 7,792,501
47	1840	Underground Conduit		$ 2,072,771	$ 38,205		$ 2,110,976	-$ 536,511	-$ 49,686		-$ 586,197	$ 1,524,779
47	1845	Underground Conductors & Devices		$ 12,125,856	$ 157,573	-$ 52,500	$ 12,230,929	-$ 4,612,609	-$ 323,746	$ 44,625	-$ 4,891,730	$ 7,339,199
47	1850	Line Transformers		$ 9,137,896	$ 649,500	-$ 10,500	$ 9,776,896	-$ 5,786,090	-$ 221,577	$ 8,925	-$ 5,998,742	$ 3,778,154
47	1855	Services (Overhead & Underground)		$ 4,224,541	$ 216,912		$ 4,441,453	-$ 1,836,931	-$ 83,994		-$ 1,920,925	$ 2,520,528
47	1860	Meters		$ 287,258			$ 287,258	-$ 78,526	-$ 11,490		-$ 90,016	$ 197,242
47	1860	Meters (Smart Meters)		$ 2,236,521	$ 116,170		$ 2,352,691	-$ 474,117	-$ 152,968		-$ 627,085	$ 1,725,606
47	1875	Street Lighting		$ -			$ -	$ -			$ -	$ -
N/A	1905	Land		$ 201,049			$ 201,049	$ -			$ -	$ 201,049
47	1908	Buildings & Fixtures		$ 2,764,631	$ 5,127,500		$ 7,892,131	-$ 302,778	-$ 100,391		-$ 403,169	$ 7,488,962
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 334,155	$ 35,000		$ 369,155	-$ 245,184	-$ 15,561		-$ 260,745	$ 108,410
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 637,806	$ 128,000		$ 765,806	-$ 462,746	-$ 75,182		-$ 537,928	$ 227,878
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 1,174,196	$ 110,000		$ 1,284,196	-$ 619,934	-$ 170,800		-$ 790,734	$ 493,462
8	1935	Stores Equipment		$ 35,824	$ 4,200		$ 40,024	-$ 20,126	-$ 2,364		-$ 22,490	$ 17,534
8	1940	Tools, Shop & Garage Equipment		$ 514,684	$ 20,000		$ 534,684	-$ 220,349	-$ 34,462		-$ 254,811	$ 279,873
8	1945	Measurement & Testing Equipment		$ 41,497	$ 19,000		$ 60,497	-$ 16,857	-$ 4,006		-$ 20,863	$ 39,634
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ 1,775,243	$ 266,697		$ 2,041,940	-$ 886,326	-$ 118,418		-$ 1,004,744	$ 1,037,196
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 8,798,900	-$ 382,523		-$ 9,181,423	$ 1,795,600	$ 246,332		$ 2,041,932	-$ 7,139,491
	etc.			$ -			$ -				$ -	$ -
				$ -								
		Total		**$ 60,119,617**	**$ 9,020,852**	**-$ 325,500**	**$ 68,814,969**	**-$ 29,566,335**	**-$ 1,782,754**	**$ 276,675**	**-$ 31,072,414**	**$ 37,742,555**
												$ 37,817,555

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 170,800
Stranded Meters	
Net Depreciation	-$ 1,611,954

1 Gross Assets Table

2 Table 2.6: Gross Assets (CGAAP)

IHDSL Gross Asset Variance Year over Year

OEB	Description	2009 Board Approved	2009 Actual	Variance 2009	2010 Actual	Variance 2010	2011 Actual	Variance 2011	2012 Bridge CGAAP	Variance 2012	2013 Bridge MIFRS	Variance to 2012
1611	Computer Software (formerly Account 1925)	972, 829	985, 064	12,235	1, 032,751	47,687	331, 066	-701,685	645, 749	314,683	924, 249	278,500
1612	Land Rights (formerly Account 1906)		-	0	-	0	-	0	-	0	-	0
1805	Land	283, 350	273, 770	-9,580	273, 770	0	273, 770	0	738, 770	465,000	738, 770	0
1806	Land Rights	993, 027	976, 547	-16,480	988, 464	11,917	982, 703	-5,761	982, 703	0	982, 703	0
1808	Buildings and Fixtures		-	0	-	0	-	0	-	0	-	0
1810	Leasehold Improvements	86, 252	86, 252	0	86, 252	0	86, 252	0	86, 252	0	86, 252	0
1815	Transformer Station Equipment - Normally Primary above 50 kV		-	0	-	0	-	0	-	0	-	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	4, 413,983	4, 388,085	-25,898	4, 431,283	43,198	4, 358,561	-72,722	4, 394,009	35,448	4, 588,431	194,422
1825	Storage Battery Equipment		-	0	-	0	-	0	-	0	-	0
1830	Poles, Towers and Fixtures	8, 084,213	7, 520,017	-564,196	8, 331,730	811,713	9, 077,888	746,158	10, 149,911	1,072,023	10, 963,064	813,153
1835	Overhead Conductors and Devices	11, 533,211	11, 265,290	-267,921	12, 001,819	736,529	13, 192,946	1,191,127	14, 357,195	1,164,249	15, 323,238	966,043
1840	Underground Conduit	1, 791,346	1, 783,830	-7,516	1, 810,440	26,610	2, 035,571	225,131	2, 072,771	37,200	2, 110,976	38,205
1845	Underground Conductors and Devices	7, 089,239	7, 726,916	637,677	11, 561,168	3,834,252	11, 721,156	159,988	12, 125,856	404,700	12, 230,929	105,073
1850	Line Transformers	8, 460,285	7, 843,588	-616,697	8, 135,538	291,950	8, 602,786	467,248	9, 137,896	535,110	9, 776,896	639,000
1855	Services	3, 746,713	3, 570,224	-176,489	3, 711,507	141,283	4, 017,136	305,629	4, 224,541	207,405	4, 441,453	216,912
1860	Meters	1, 901,655	679, 096	-1,222,559	187, 025	-492,071	287, 258	100,233	287, 258	0	287, 258	0
1860	Meters (Smart Meters)			0	-	0	-	0	2, 236,521	2,236,521	2, 352,691	116,170
1875	Street Lighting		7, 646	7,646	7, 646	0	7, 646	0	-	-7,646	-	0
1905	Land	201, 049	201, 049	0	201, 049	0	201, 049	0	201, 049	0	201, 049	0
1908	Buildingd &Fixtures	717, 362	702, 948	-14,414	737, 784	34,836	739, 631	1,847	2, 764,631	2,025,000	7, 892,131	5,127,500
1910	Leashold Improvements			0		0	-	0	-	0	-	0
1915	Office Furniture and Equipment (10 years)	281, 995	273, 093	-8,902	294, 399	21,306	308, 655	14,256	334, 155	25,500	369, 155	35,000
1915	Office Furniture and Equipment (5 years)			0	-	0	-	0	-	0	-	0
1920	Computer Equipment - Hardware	513, 985	807, 849	293,864	872, 059	64,210	515, 306	-356,753	637, 806	122,500	765, 806	128,000
1920	Computer Equip.-Hardware(Post Mar. 22/04)	109, 254		-109,254	-	0	-	0	-	0	-	0
1920	Computer Equip.-Hardware(Post Mar. 19/07)	240, 653		-240,653	-	0	-	0	-	0	-	0
1925	Computer Software		-	0		0		0		0		0
1930	Transportation Equipment	357, 580	242, 514	-115,066	836, 916	594,402	1, 174,196	337,280	1, 174,196	0	1, 284,196	110,000
1935	Stores Equipment	23, 174	26, 357	3,183	30, 118	3,761	31, 824	1,706	35, 824	4,000	40, 024	4,200
1940	Tools, Shop and Garage Equipment	168, 136	165, 293	-2,843	469, 385	304,092	487, 684	18,299	514, 684	27,000	534, 684	20,000
1945	Measurement and Testing Equipment	25, 102	23, 093	-2,009	23, 690	597	32, 997	9,307	41, 497	8,500	60, 497	19,000
1950	Power Operated Equipment		-	0	-	0	-	0	-	0	-	0
1955	Communication Equipment		-	0	-	0	-	0	-	0	-	0
1955	Communication Equipment (Smart Meter)			0	-	0	-	0	-	0	-	0
1960	Miscellaneous Equipment		-	0	-	0	-	0	-	0	-	0
1970	Load Management Controls - Customer Premises		-	0		0		0		0		0
1975	Load Management Controls - Utility Premises		-	0	-	0	-	0	-	0	-	0
1980	System Supervisory Equipment	1, 359,315	1, 272,865	-86,450	1, 324,906	52,041	1, 324,906	0	1, 775,243	450,337	2, 041,940	266,697
1985	MIscellaneous Fixed Assets		-	0	-	0	-	0	-	0	-	0
1995	Contributions and Grants	- 5, 447,731	- 5, 391,302	56,429	- 7, 193,539	-1,802,237	- 7, 193,539	0	- 8, 798,900	-1,605,361	- 9, 181,423	-382,523
	Total before Work in Process	**47,905,977**	**45,430,084**	**-2,475,893**	**50,156,160**	4,726,076	**52,597,448**	2,441,288	**60,119,617**	7,522,169	**68,814,969**	8,695,352

Variance Analysis on Gross Assets:

The Gross Asset Variance analysis for the variances highlighted in Table 2.6 of Exhibit 2, Tab 2, Schedule 2 is provided as follows.

2009 Board Approved vs. 2009 Actual

The 2009 Board Approved Fixed Asset value was offset by lower capital spending than the approved capital spend and the offset of meter disposals of -$1,270,515.

2009 Actual vs. 2010 Actual

The increase in gross assets for 2009 Actual compared to 2010 Actual are the result of capital expenditures in 2010 pushed forward from 2009 and the purchase of vehicles and tools of approximately $900,000 for the internalization of IHDSL's line crew.

2010 Actual vs. 2011 Actual

The increase in gross assets for 2010 Actual compared to 2011 Actual are the result of capital expenditures including disposals and an additional $320,000 for vehicles and tools for IHDSL's line crew.

2011 Actual vs. 2012 Bridge Year

The increase in gross assets for 2012 is a result of capital spending during the year, land purchases of $465,000 for a future transformer station and $2,000,000 for IHDSL's new building facility. The Initial investment to begin the construction of the new IHDSL Head Office and

Operations Center is slated to start construction in the fall of 2012. The new building investment is to enhance IHDSL's effectiveness and operations with all departments under one roof rather than the five (5) buildings currently being utilized. Accessibility issues, growth requirements and structural deficiencies have prompted this required expansion.

2012 Bridge Year vs. 2013 Test Year

The increase in gross assets for the 2012 Bridge Year compared to the 2013 Test Year are the result of capital expenditures in 2013, plus the addition of Smart Meters $2,352,691 to the opening balance, and the completion of IHDSL's Head Office and Operations Centre.

Accumulated Amortization Table

Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2011 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2011 (a)	Less Fully Depreciated (b)		Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2011 Depreciation Expense (h) = (e) / (f)	2011 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 1,032,751	$ 823,485	80%	$ 209,267	$ 73,245	$ 245,889	3.00	33.33%	$ 81,963.00	$ 81,963.00	$ -
1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1805	Land	$ 273,770			$ 273,770	$ -	$ 273,770			$ -	$ -	$ -
1806	Land rights	$ 988,464	$ 230,654	23%	$ 757,810	$ 1,981	$ 758,800	50.00	2.00%	$ 15,176.00	$ 15,176.00	$ 0.00
1808	Buildings	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1810	Leasehold Improvements	$ 86,252	$ -		$ 86,252	$ -	$ 86,252	25.00	4.00%	$ 3,450.08	$ 3,450.00	$ 0.08
1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 4,431,283	$ 1,376,999	31%	$ 3,054,285	$ 152,331	$ 3,130,450	25.00	4.00%	$ 125,218.00	$ 125,218.00	$ -
1825	Storage Battery Equipment	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 8,331,730	$ 99,685	1%	$ 8,232,045	$ 935,010	$ 8,699,550	25.00	4.00%	$ 347,982.00	$ 347,982.00	$ -
1835	Overhead Conductors & Devices	$ 12,001,819	$ 5,518,804	46%	$ 6,483,016	$1,491,019	$ 7,228,525	25.00	4.00%	$ 289,141.00	$ 289,141.00	$ -
1840	Underground Conduit	$ 1,810,440	$ 112,556	6%	$ 1,697,884	$ 225,131	$ 1,810,450	25.00	4.00%	$ 72,418.00	$ 72,418.00	-$ 0.00
1845	Underground Conductors & Devices	$ 11,561,168	$ 46,545	0%	$ 11,514,623	$ 251,455	$ 11,640,350	25.00	4.00%	$ 465,614.00	$ 465,614.00	$ 0.00
1850	Line Transformers	$ 8,135,538	$ 53,005	1%	$ 8,082,533	$ 487,484	$ 8,326,275	25.00	4.00%	$ 333,051.00	$ 333,051.00	$ -
1855	Services (Overhead & Underground)	$ 3,711,507	$ 2,228	0%	$ 3,709,279	$ 306,192	$ 3,862,375	25.00	4.00%	$ 154,495.00	$ 154,495.00	$ -
1860	Meters	$ 187,025	$ -	0%	$ 187,025	$ 10,308	$ 192,179	25.00	4.00%	$ 7,687.16	$ 27,067.00	-$ 19,379.84
1860	Meters (Smart Meters)	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1875	Street Lighting	$ 7,646		0%	$ 7,646	$ -	$ 7,646	25.00	4.00%	$ 305.84	$ 305.00	$ 0.84
1905	Land	$ 201,049		0%	$ 201,049	$ -	$ 201,049	-		$ -	$ -	$ -
1908	Buildings & Fixtures	$ 737,784		0%	$ 737,784	$ 1,847	$ 738,708	25.00	4.00%	$ 29,548.30	$ 29,548.00	$ 0.30
1910	Leasehold Improvements	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 294,399	$ 151,387	51%	$ 143,012	$ 14,256	$ 150,140	10.00	10.00%	$ 15,014.00	$ 15,014.00	$ -
1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 872,059	$ 565,158	65%	$ 306,901	$ 16,388	$ 315,095	5.00	20.00%	$ 63,019.00	$ 63,019.00	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1930	Transportation Equipment	$ 836,916	$ -	0%	$ 836,916	$ 297,131	$ 985,482	5.00	20.00%	$ 197,096.30	$ 220,718.00	-$ 23,621.70
1935	Stores Equipment	$ 30,118	$ 11,481	38%	$ 18,637	$ 1,706	$ 19,490	10.00	10.00%	$ 1,949.00	$ 1,949.00	$ -
1940	Tools, Shop & Garage Equipment	$ 469,385	$ 156,809	33%	$ 312,576	$ 58,448	$ 341,800	10.00	10.00%	$ 34,180.00	$ 34,180.00	$ -
1945	Measurement & Testing Equipment	$ 23,690	$ 3,844	16%	$ 19,847	$ 9,307	$ 24,500	10.00	10.00%	$ 2,450.00	$ 2,450.00	$ -
1950	Power Operated Equipment	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1955	Communications Equipment	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1980	System Supervisor Equipment	$ 1,324,906			$ 1,324,906	$ 82,487	$ 1,366,150	15.00	6.67%	$ 91,076.63	$ 91,077.00	-$ 0.37
1985	Miscellaneous Fixed Assets	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1995	Contributions & Grants	-$ 7,193,539	-$ 188,568		-$ 7,004,972	-$ 521,407	-$ 7,265,675	25.00	4.00%	-$ 290,627.00	-$ 290,627.00	$ -
etc.					$ -		$ -			$ -		$ -
					$ -		$ -			$ -		$ -
	Total	$ 50,156,160	$ 8,964,071	18%	$ 41,192,089	$ 3,894,319	$ 43,139,249			$ 2,040,207.32	$ 2,083,208.00	-$ 43,000.68

Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2012 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2012 (a)	Less Fully Depreciated (b)		Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2012 Depreciation Expense (h) = (e) / (f)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 363,599	$ 162,914	-$ 660,571	$ 200,685	$ 282,150	$ 341,760	3.00	33.33%	$ 113,920.00	$ 113,920.00	$ -
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1805	Land	$ 273,770	$ -	$ -	$ 273,770	$ 465,000	$ 506,270	-	0.00%	$ -	$ -	$ -
1806	Land rights	$ 982,703	$ 239,103	$ 8,449	$ 743,600	$ -	$ 743,600	50.00	2.00%	$ 14,872.00	$ 14,872.00	$ 0.00
1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	$ 86,252	$ 3,452	$ 3,452	$ 82,800	$ -	$ 82,800	25.00	4.00%	$ 3,312.00	$ 3,312.00	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 4,358,561	$ 1,353,335	-$ 23,664	$ 3,005,226	$ 35,448	$ 3,022,950	25.00	4.00%	$ 120,918.00	$ 120,918.00	$ -
1825	Storage Battery Equipment	$ -	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 9,077,888	$ 726,325	$ 626,640	$ 8,351,564	$1,172,023	$ 8,937,575	25.00	4.00%	$ 357,503.00	$ 357,503.00	$ -
1835	Overhead Conductors & Devices	$13,192,946	$ 6,253,571	$ 734,767	$ 6,939,376	$1,314,249	$ 7,596,500	25.00	4.00%	$ 303,860.00	$ 303,860.00	$ -
1840	Underground Conduit	$ 2,035,571	$ 297,546	$ 184,991	$ 1,738,025	$ 37,200	$ 1,756,625	25.00	4.00%	$ 70,265.00	$ 70,265.00	-$ 0.00
1845	Underground Conductors & Devices	$11,721,156	$ 546,406	$ 499,861	$ 11,174,750	$ 454,700	$ 11,402,100	25.00	4.00%	$ 456,084.00	$ 456,084.00	$ 0.00
1850	Line Transformers	$ 8,602,786	$ 609,566	$ 556,561	$ 7,993,220	$ 545,110	$ 8,265,775	25.00	4.00%	$ 330,631.00	$ 330,631.00	$ -
1855	Services (Overhead & Underground)	$ 4,017,136	$ 309,264	$ 307,036	$ 3,707,873	$ 207,405	$ 3,811,575	25.00	4.00%	$ 152,463.00	$ 152,463.00	$ -
1860	Meters	$ 287,258	$ -	$ -	$ 287,258	$ -	$ 287,258	25.00	4.00%	$ 11,490.32	$ 11,490.32	$ -
1860	Meters (Smart Meters)	$ 2,162,281	$ -	$ -	$ 2,162,281	$ 74,240	$ 2,199,401	15.00	6.67%	$ 146,626.73	$ 146,621.68	$ 5.05
1875	Street Lighting	$ 7,646	$ 7,646	$ 7,646	$ -	$ -	$ -	25.00	4.00%	$ -	$ -	$ -
1905	Land	$ 201,049	$ -	$ -	$ 201,049	$ -	$ 201,049	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 739,631	$ -	$ -	$ 739,631	$2,025,000	$ 1,752,131	25.00	4.00%	$ 70,085.24	$ 28,866.00	$ 41,219.24
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 308,655	$ 196,045	$ 44,658	$ 112,610	$ 25,500	$ 125,360	10.00	10.00%	$ 12,536.00	$ 12,536.00	$ -
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 515,306	$ 263,231	-$ 301,927	$ 252,075	$ 122,500	$ 313,325	5.00	20.00%	$ 62,665.00	$ 62,665.00	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ 1,174,196		$ -	$ 1,174,196	$ -	$ 1,174,196	7.35	13.61%	$ 159,754.56	$ 159,800.00	-$ 45.44
1935	Stores Equipment	$ 31,824	$ 14,284	$ 2,803	$ 17,540	$ 4,000	$ 19,540	10.00	10.00%	$ 1,954.00	$ 1,954.00	$ -
1940	Tools, Shop & Garage Equipment	$ 487,684	$ 180,064	$ 23,255	$ 307,620	$ 27,000	$ 321,120	10.00	10.00%	$ 32,112.00	$ 32,112.00	$ -
1945	Measurement & Testing Equipment	$ 32,997	$ 10,937	$ 7,094	$ 22,060	$ 8,500	$ 26,310	10.00	10.00%	$ 2,631.00	$ 2,631.00	$ -
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 1,407,393	$ 132,313	$ 132,313	$ 1,275,080	$ 367,850	$ 1,459,005	15.00	6.67%	$ 97,267.00	$ 97,267.00	$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	-$ 7,714,946	-$ 739,898	-$ 551,331	-$ 6,975,048	-$1,083,954	-$ 7,517,025	25.00	4.00%	-$ 300,681.00	-$ 300,681.00	$ -
etc.					$ -		$ -		0.00%	$ -		$ -
					$ -		$ -		0.00%	$ -		$ -
	Total	$54,353,342	$ 10,566,102		$ 43,787,240	$6,083,921	$ 46,829,200			$ 2,220,268.86	$ 2,179,090.00	$ 41,178.86

Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2012 MIFRS

Account	Description	Opening NBV as at Jan 1, 2012 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2012 Depreciation Expense (k) = (j) + (h)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2012 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2012 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 119,195	$ 282,150	1.78	3.00	33.33%	$ 66,895	$ 47,025	$ 113,920	$ 113,920	-$ 0	$ 94,050	$ 32,550	$ 128,395
1612	Land Rights (Formally known as Account 1906)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1805	Land	$ 273,770	$ 465,000			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1806	Land rights	$ 424,717	$ -	28.56	50.00	2.00%	$ 14,872	$ -	$ 14,872	$ 14,872	$ 0	$ -	$ 297	$ 14,575
1808	Buildings	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ 51,752	$ -	15.63	25.00	4.00%	$ 3,312	$ -	$ 3,312	$ 3,312	$ 0	$ -		$ 3,312
1815	Transformer Station Equipment >50 kV	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 2,035,685	$ 35,448	22.51	40.00	2.50%	$ 90,435	$ 443	$ 90,878	$ 90,878	-$ 0	$ 886		$ 91,321
1825	Storage Battery Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 4,791,235	$ 1,172,023	27.54	45.00	2.22%	$ 173,990	$ 13,022	$ 187,013	$ 187,013	-$ 0	$ 26,045		$ 200,035
1835	Overhead Conductors & Devices	$ 5,716,025	$ 1,314,249	41.88	60.00	1.67%	$ 136,486	$ 10,952	$ 147,438	$ 147,438	-$ 0	$ 21,904		$ 158,390
1840	Underground Conduit	$ 1,547,804	$ 37,200	32.06	40.00	2.50%	$ 48,279	$ 465	$ 48,744	$ 48,744	$ 0	$ 930		$ 49,209
1845	Underground Conductors & Devices	$ 7,382,140	$ 454,700	23.78	40.00	2.50%	$ 310,409	$ 5,684	$ 316,093	$ 316,093	$ 0	$ 11,368		$ 321,777
1850	Line Transformers	$ 3,014,840	$ 545,110	15.09	40.00	2.50%	$ 199,830	$ 6,814	$ 206,644	$ 206,644	$ 0	$ 13,628		$ 213,458
1855	Services (Overhead & Underground)	$ 2,259,956	$ 207,405	29.09	50.00	2.00%	$ 77,677	$ 2,074	$ 79,751	$ 79,751	-$ 0	$ 4,148		$ 81,825
1860	Meters	$ 220,222	$ -	19.17	25.00	4.00%	$ 11,490	$ -	$ 11,490	$ 11,490	-$ 0	$ -		$ 11,490
1860	Meters (Smart Meters)	$ 1,834,786	$ 74,240	12.73	15.00	6.67%	$ 144,147	$ 2,475	$ 146,621	$ 146,622	-$ 0	$ 4,949		$ 149,096
1875	Street Lighting	$ 4,976	$ -		-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1905	Land	$ 201,049	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 465,719	$ 25,000	16.28	50.00	2.00%	$ 28,616	$ 250	$ 28,866	$ 28,866	-$ 0	$ 500		$ 29,116
1910	Leasehold Improvements	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 76,007	$ 25,500	6.75	10.00	10.00%	$ 11,261	$ 1,275	$ 12,536	$ 12,536	$ 0	$ 2,550		$ 13,811
1915	Office Furniture & Equipment (5 years)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 115,225	$ 122,500	2.29	5.00	20.00%	$ 50,415	$ 12,250	$ 62,665	$ 62,665	-$ 0	$ 24,500	$ 12,533	$ 62,382
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 714,062	$ -	4.47	5.00	20.00%	$ 159,800	$ -	$ 159,800	$ 159,800	$ 0	$ -		$ 159,800
1935	Stores Equipment	$ 13,652	$ 4,000	7.79	10.00	10.00%	$ 1,754	$ 200	$ 1,954	$ 1,954	-$ 0	$ 400		$ 2,154
1940	Tools, Shop & Garage Equipment	$ 299,447	$ 27,000	9.73	10.00	10.00%	$ 30,762	$ 1,350	$ 32,112	$ 32,112	$ 0	$ 2,700		$ 33,462
1945	Measurement & Testing Equipment	$ 18,771	$ 8,500	8.51	10.00	10.00%	$ 2,206	$ 425	$ 2,631	$ 2,631	-$ 0	$ 850		$ 3,056
1950	Power Operated Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 618,334	$ 367,850	7.27	15.00	6.67%	$ 85,005	$ 12,262	$ 97,267	$ 97,267	-$ 0	$ 24,523		$ 109,528
1985	Miscellaneous Fixed Assets	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 6,144,728	-$ 1,083,954	29.28	35.00	2.86%	-$ 209,897	-$ 15,485	-$ 225,382	-$ 225,382	$ 0	-$ 30,970		-$ 240,867
etc.						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
	Total	$ 26,054,641.00	$ 4,083,921.00				$ 1,437,744	$ 101,481	$ 1,539,226	$ 1,539,226	$ 0	$ 202,961	$ 45,380	$ 1,595,325

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Appendix 2-CH
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2013 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2013 Depreciation Expense [1] (h)=2012 Full Year Depreciation + ((d)*0.5)/(f)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (I)	Variance [2] (m) = (h) - (I)
1611	Computer Software (Formally known as Account 1925)	278,500	3.00	33.33%	$ 174,811	$ 174,811	$ 0
1612	Land Rights (Formally known as Account 1906)	-	-	0.00%	$ -	$ -	$ -
1805	Land	-	-	0.00%	$ -	$ -	$ -
1806	Land rights	-	-	0.00%	$ 14,575	$ 14,575	$ 0
1808	Buildings	-	-	0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	-	25.00	4.00%	$ 3,312	$ 3,312	$ 0
1815	Transformer Station Equipment >50 kV	-	-	0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	194,422	40.00	2.50%	$ 93,751	$ 93,752	-$ 1
1825	Storage Battery Equipment	-	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	918,153	45.00	2.22%	$ 210,237	$ 210,238	-$ 1
1835	Overhead Conductors & Devices	1,123,543	60.00	1.67%	$ 167,753	$ 167,753	-$ 0
1840	Underground Conduit	38,205	40.00	2.50%	$ 49,687	$ 49,686	$ 1
1845	Underground Conductors & Devices	157,573	40.00	2.50%	$ 323,747	$ 323,746	$ 1
1850	Line Transformers	649,500	40.00	2.50%	$ 221,577	$ 221,577	-$ 0
1855	Services (Overhead & Underground)	216,912	50.00	2.00%	$ 83,994	$ 83,994	-$ 0
1860	Meters	-	25.00	4.00%	$ 11,490	$ 11,490	$ 0
1860	Meters (Smart Meters)	116,170	15.00	6.67%	$ 152,968	$ 152,968	$ 0
1875	Street Lighting	-	-	0.00%	$ -	$ -	$ -
1905	Land	-	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	7,127,500	50.00	2.00%	$ 100,391	$ 100,391	-$ 0
1910	Leasehold Improvements	-	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	35,000	10.00	10.00%	$ 15,561	$ 15,561	$ 0
1915	Office Furniture & Equipment (5 years)	-	-	0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	128,000	5.00	20.00%	$ 75,182	$ 75,182	-$ 0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	-	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	-	-	0.00%	$ -	$ -	$ -
1930	Transportation Equipment	110,000	5.00	20.00%	$ 170,800	$ 170,800	$ 0
1935	Stores Equipment	4,200	10.00	10.00%	$ 2,364	$ 2,364	-$ 0
1940	Tools, Shop & Garage Equipment	20,000	10.00	10.00%	$ 34,462	$ 34,462	$ 0
1945	Measurement & Testing Equipment	19,000	10.00	10.00%	$ 4,006	$ 4,006	-$ 0
1950	Power Operated Equipment	-	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	-	-	0.00%	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	-	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	-	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	-	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	266,697	15.00	6.67%	$ 118,418	$ 118,418	$ 0
1985	Miscellaneous Fixed Assets	-	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	- 382,523	35.00	2.86%	-$ 246,332	-$ 246,332	$ 0
etc.				0.00%	$ -		$ -
				0.00%	$ -		$ -
	Total	$11,020,852			$ 1,782,754	$ 1,782,754	-$ 0
	Depreciation expense adjustment resulting from amortization of Account 1575				-$ 639,864.00		
	Total Depreciation expense to be included in the test year revenue requirement				**$ 1,142,890**		

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Variance Analysis on Accumulated Amortization:

Changes in accumulated amortization 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 identified assets.

The preceding tables reflect the changes in accumulated amortization from 2009 to the 2013 Test Year under MIFRS. The change in accumulated amortization is a result of capital expenditures, amortization expense each year, write-offs of fully-amortized assets and disposals as appropriate over the four year period. Amortization expense has decreased in 2012 and 2013 to reflect increase in the useful lives of the assets in accordance with the Asset Depreciation Study dated July 8, 2010. Please refer to Exhibit 4, Tab 2, Schedule 7 for details of annual amortization expense for each asset account.

CAPITAL BUDGET:

IHDSL's Asset Management Plan identifies the capital projects required over a 3 year period based on the best available information for each year. The capital budget forecast is influenced significantly by condition data that is collected each year on aging infrastructure and as such, IHDSL may be required to adjust the capital project forecast as the knowledge of its system needs increases. As provided in Exhibit 2, Tab 3, Schedule 2, a significant portion of IHDSL's capital investments are customer or municipal driven. All proposed capital projects for the 2012 Bridge Year and 2013 Test Year will be completed and in service in that year. Details of IHDSL's capital budget for these periods are provided in Tables 3.2 to 3.6.

Provincial Sales Tax Impact

As a result of the implementation of HST in the province of Ontario on July 1, 2011, IHDSL has considered the reduction in capital expenditures relating to the purchase of products and services

due to the increased input tax credit (ITC). Neither the 2012 Bridge Year forecast nor the 2013 Test Year budget for capital expenditures includes tax on purchases of products or services made after July 1, 2011.

CAPITAL BUDGET

Introduction:

IHDSL has been, and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through effective capital spending. The capital spending for the 2012 Bridge Year and the 2013 Test year is broken down by account and by project in Exhibit 2, Tab 3, Schedule 2.

Table 3.1 Capital Spend Summary

Year	Distribution Plant	Capital Contributions	Net Distribution Plant	General Plant	Tot Capital net Contributions	$ Increase /Decrease	% Increase /Decrease
2008	$ 2, 124,095	$ 251, 278	$ 1,872,817	$ 272,968	$ 2,145,785		
2009	$ 3,301,876	$ 825,193	$ 2,476,683	$ 345,886	$ 2,822,569	$ 676,784	32%
2010	$ 5,394,040	$ 1,802,237	$ 3,591,803	$ 1,134,273	$ 4,726,076	$ 1,903,507	67%
2011	$ 3,771,360	$ 521,407	$ 3,249,953	$ 644,366	$ 3,894,319	-$ 831,757	-18%
2012	$ 4,316,759	$ 1,083,954	$ 3,232,805	$ 2,955,656	$ 6,188,461	$ 2,294,142	59%
2013	$ 3,381,452	$ 349,497	$ 3,031,955	$ 5,988,897	$ 9,020,852	$ 2,832,391	46%

The updated filing requirements for Exhibit 2 (Rate Base) request actual historical summary information for the last 5 years. IHDSL has provided below tables by year providing an overview of all capital jobs, including capital jobs that are under the $50,000 m ateriality threshold. For each year IHDSL has provided 3 tables,

- Summary of capital jobs
- Summary of capital jobs by category
- Overview of capital jobs

Capital jobs have been identified by the following category definitions;

1. **Customer Demand**: IHDSL is obligated under the DSC to connect new customer services. T hese new services or service upgrades may be for new subdivisions, infilling lots, town houses or apartment, commercial and industrial buildings.

2. **Infrastructure Replacement and Betterments:** These projects involve the replacement of deteriorated or damaged distribution structures and electrical equipment.

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 IHDSL and its surrounding utilities.

4. **Reliability and System Automation:** The main driver for these investments is an analysis of what measures could be undertaken to improve IHDSL reliability performance as measured by SAIDI, SAIFI and CAIDI indices. These indices are indicators of the reliability of IHDSL'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 IHDSL.

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.

6. **Substations:** Substation investments are undertaken to improve or maintain reliability to large numbers of customers and to maintain security and safety at the substations.

7. **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 additions or upgrades. These projects benefit many customers.

8. **Metering:** Capital expenditures in this pool include meter installations, meter upgrades, and the capital components of wholesale and retail meter verification activities.

9. **Substations:** Distribution substations (DS) are used to transfer power received from the transformer stations via primary distribution feeders. Investments are undertaken to improve or maintain reliability to a large number of customers and to maintain security and safety at the substations.

10. **Facility:** Capital expenditures in this pool include costs associated with new facility requirements.

11. **Transport:** Capital expenditures in this pool include costs associated with vehicles for HDSL's line, metering and Technical staff.

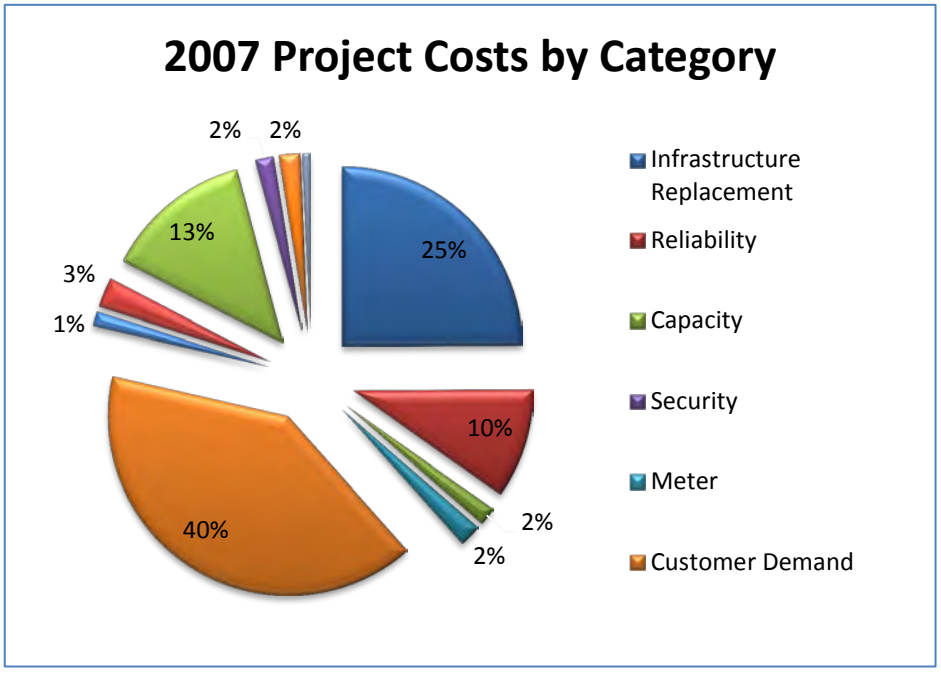
12. **Tools:** Capital expenditures in this pool include costs associated with tools required by IHDSL's technical staff and line crew

2007 Capital Projects by Category & Cost

Projects	Category	Cost
2007 Distribution Plant		
9M3 9M6 Extension	Capacity	35,179
Pole relocate	Customer Demand	50,011
Extend 44000 volt sub-trans	Reliability	210,551
Private primary service	Customer Demand	19,639
Booster station for water supply	Customer Demand	36,905
Alcona voltage conversion	Infrastructure	315,260
Road relocate 9 double circuit	Customer Demand	131,068
Town administration building underground primary	Customer Demand	39,834
Subaru car dealership	Customer Demand	38,099
Mercedes car dealership	Customer Demand	36,023
New D.S. on Commerce Park Drive	Customer Demand	30,250
Woodland Park subdivision	Customer Demand	27,152
Base	Metering	43,048
Base	Customer Demand	444,473
Base	Infrastructure	214,307
Base	Substation	28,376
Sub-Total		**1,700,175**
2007 General Plant		
Portables, paving, window replacement, fencing & shelving	Facilities	56,911
Hardware and software	Hardware and Software	282,348
Truck purchase	Transportation	34,820
Scada wide screen, labour and material	Communication	40,211
Miscellaneous	Tools & Equipment	13,377
Sub-Total		**427,667**
20097Grand Total		**2,127,842**

2007 Project Costs by Category

Category	Cost
Infrastructure Replacement	529,567
Reliability	210,551
Capacity	35,179
Meter	43,048
Customer Demand	853,454
Substation	28,376
Facilities	56,911
Hardware and Software	282,348
Transportation	34,820
Communication	40,211
Tools & Equipment	13,377
2007 Grand Total	**2,127,842**



IHDSL Capital Project Overview – 2007

2007 Distribution Plant

ID	Total	Description	Category	Project Overview
CDP2007-1	$35,179	9M3 9M6 Extension	Capacity	New line construction to bring in the 9M3 and 9M6 from Hydro One - Innisfil Hydro's portion.
	$50,011	Pole relocate	Cust Dem	Pole relocate for entrance into subdivision.
CDP2007-3	$210,551	Extend 44000 volt sub-trans	Reliability	Extend the 9M1, 9M4 44kV circuits and create tie points to the new 9M3 and 9M6 44kV circuits from Hydro One. 5 Sideroad south of Innisfil Beach Road.
	$19,639	Private primary service	Cust Dem	Service to 815 Harbour private entry.
	$36,905	Booster station for water supply	Cust Dem	Town of Innisfil booster station for water supply.
CDP2007-5	$315,260	Alcona voltage conversion	Infrastructure	Voltage Conversion Phase 2 to off load Alcona D.S. for removal.
CDP2007-2	$131,068	Road relocate 9 double circuit	Cust Dem	Double circuit 9M3/9M6 44kV feeders for Innisfil Hydro supply.
CDP2007-6	$39,834	Town admin building u/g primary	Cust Dem	To relocate approximately eight (8) double circuit 44kV poles for turning lane into the new Town of Innisfil recreational. centre.
	$38,099	Subaru car dealership	Cust Dem	Underground primary service for Subaru car dealership.
	$36,023	Mercedes car dealership	Cust Dem	Underground primary service for Mercedes car dealership.
CDP2007-4	$30,250	Shell and Tim's	Cust Dem	44kV motor switch for switching provisions, for the new D.S. on Commerce Park.

ID	Total	Description	Category	Project Overview
	$27,152	Woodland Park sub-division	Cust Dem	
	$43,048	Miscellaneous	Metering	Miscellaneous customer metering.
	$444,473	Miscellaneous	Cust Dem	Miscellaneous customer demand.
	$214,307	Miscellaneous	Infrastructure	Miscellaneous infrastructure.
	$28,376	Substation investments	Substation	
TOTAL:	**$1,700,175**			

2007 General Plant

ID	Total	Description	Category	Project Overview
CO2007-9	$28,536	Miscellaneous	Facilities	Miscellaneous building fixtures – CS portables; paving parking lot.
CGP-Bldg-6	$14,500	Windows	Facilities	Window replacement in customer service building
CO2007-8	$13,875	Office equipment	Facilities	Secure the rear portion of the stores building with fencing and shelving.
CGP-GIS-4	$108,353	Hardware	Computer	Bandwith Redundancy; Replace Exchange Server; New Plotter; Diskkeeper/Symantec annual updates; Continued Workstation Upgrades; AutoCAD Software-new version; Workstation Replacement.
CGP-1	$173,995	Software	Computer	• Two Great Plains and Wennsoft user licenses, due to maximizing out on us er availability. (Bar Coding software took one license when implemented.) • Great Plains Fixed Asset module, as we do not have an asset sub ledger tracking assets individually; control issue. • Penny payroll software to automate the current payroll input process, saving time by HR Admin and Accounts Payable. • Great Plains version 9 upg rade, to remain current for support

ID	Total	Description	Category	Project Overview
				reasons.
CO2007-10	$34,820	Truck	Transport	Purchase of one truck to replace 1998 Pontiac Transport.
	$5,294	Distribution station	Communication	BD distribution station
	$4,198	Scada	Communication	Scada wide screen.
CO2007-7	$30,719	Scada	Communication	Labour & material to supervisory accounts to monitor and operate seven (7) new switch locations.
	$561	Miscellaneous	Tools & Equip	Miscellaneous stores equipment
	$6,541	Miscellaneous	Tools & Equip	Miscellaneous tools and shop equipment
	$6,275	Miscellaneous	Tools & Equip	Miscellaneous testing equipment
TOTAL:	**$427,667**			

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2008 Capital Projects by Category & Cost

Projects	Category	Cost
2007 Distribution Plant		
CDP-1 Line Ext 15th Line West of Cookstown	Regulatory	85,704
CDP-2 44kV Line Ext BBP	Security	362,911
CDP-3 Line Rebuild Hwy 27	Regulatory	101,113
CDP-4 Guard Rails	Reliability	163,902
CDP-7 44kV Mechanized Altdi-Ruptor Scada	Reliability	157,953
CDP-8 27.6V Mechanized Scada-mate switch	Reliability	126,497
CDP-10 Pole Replacement	Infrastructure Replacement	209,696
CDP-12 Meter Analyzer	Meter	16,773
CDP-14 Conventional Meters	Meter	55,296
Base	Customer Demand	592,972
Sub-Total		**1,872,817**
2007 General Plant		
GF-002 Wide screen monitors	Hardware and Software	1,928
GB-001 Hardware and Software	Hardware and Software	88,384
GB-002 Operations Offices	Facility	11,402
GB-003 Stores and Portables	Facility	92,435
GB-004 Server & 2 Scanners	Hardware and Software	35,487
GO-002 New Vehicle	Transportation	28,507
GO-003 Stores Equipment	Tools	3,431
GO-004 Tools, Shop and Garage Equipment	Tools	9,467
GO-005 Measurement & Testing Equipment	Tools	1,927
Miscellaneous		0
Sub-Total		**272,968**
20097Grand Total		**2,145,785**

2008 Project Costs by Category

Category	Cost
Infrastructure Replacement	209,696
Reliability	448,352
Security	362,911
Meter	72,069
Customer Demand	592,972
Facilities	103,837
Hardware and Software	125,799
Transportation	28,507
Tools & Equipment	14,825
Regulatory	186,817
2007 Grand Total	**2,145,785**

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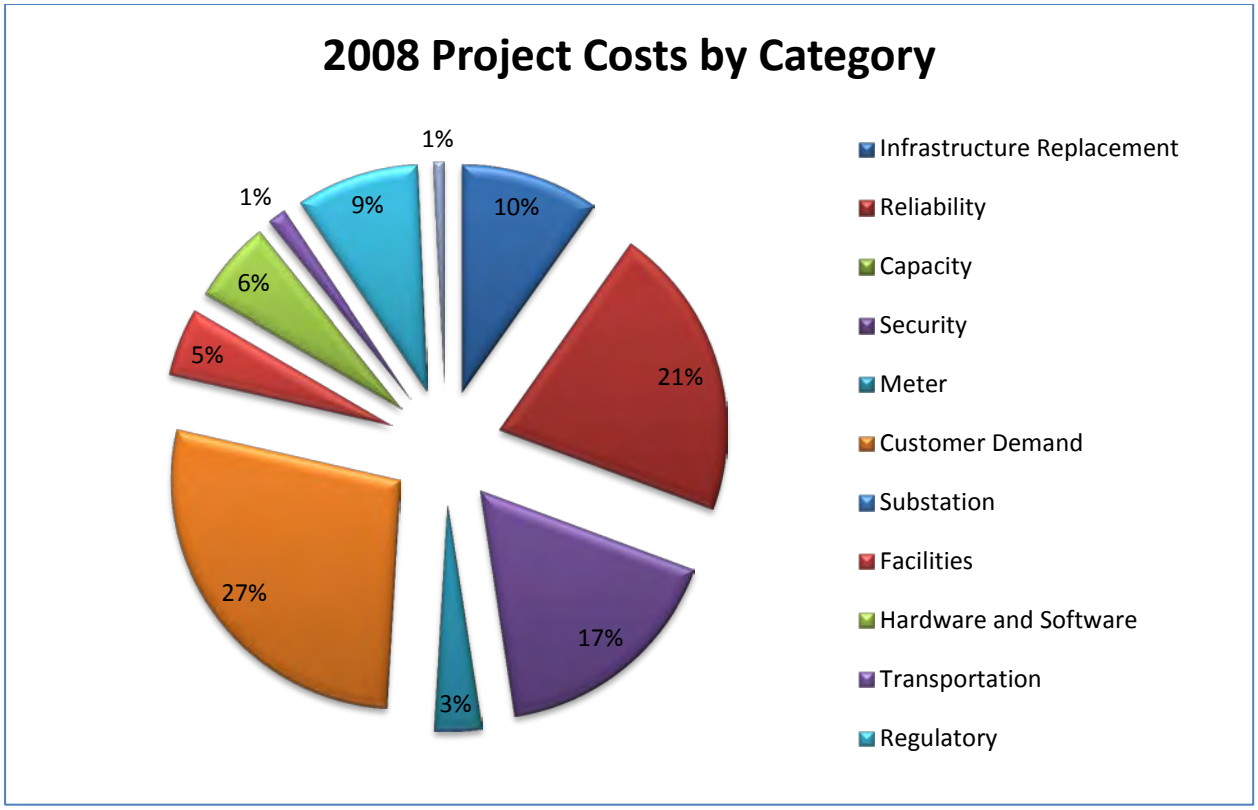

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IHDSL Capital Project Overview – 2008

2008 Distribution Plant

ID	Total	Description	Category	Project Overview
CDP-1	$85,704	Line Ext 15th Line West of Cookstown	Regulatory	The construction of this line will eliminate the load transfer issue that presently exists within Innisfil Hydro Distribution territory going west of the Cookstown west D.S. The line will be extended to the last Innisfil customer at the Innisfil/Hydro one border. At present Hydro One services Innisfil Hydro customers within this section.
CDP-2	$362,911	44kV Line Ext BBP	Security	This 44 KV line extension scheduled to be half completed in 2008 and the remainder to be built in 2009 and is to provide redundancy for both the Kempenfelt Center and the Big Bay Point D.S. stations that are presently radial fed from Lockhart Rd north. This line upon completion will loop these stations together for better reliability should problems occur in the 44KV north of Lockhart Rd. This project will also provide a 27.6kV feeder tie in future between the Brian Wilson D.S. and the new, to be constructed 27.6kV Big Bay Point D.S.
CDP-3	$101,113	Line Rebuild Hwy 27	Regulatory	The re-construction of this line will eliminate the load transfer issue that presently exists within Innisfil Hydro Distribution territory south of Cookstown on County Rd 27, two spans south of Kidds Lane to the Innisfil Hydro border. At present Hydro One services Innisfil Hydro customers within this section.
CDP-4	$163,902	Guard Rails	Reliability	New guard rails around rural 44kV motor operated switches will help protect Innisfil Hydro's investments on a single pole. Strategic locations in rural environments will be selected to keep safe the motor mech, pole and switch at top ensuring protection while also protecting from a prolonged outage should the pole be hit.
CDP-5	$ 0	Urbanization- *Re-Allocated to 2009*		The Town of Innisfil initiated a road widening and underground urbanization of Innisfil Beach Road Precinct two (2b). All overhead lines and distribution assets will be relocated and converted to underground infrastructure between the 25th Side Rd and St. John's Rd. Electrical design and installation based off engineered plans developed and supplied by Town of Innisfil engineering department.
CDP-6	$ 0	Carried Forward H1 double circuit. *Re-Allocated to 2009*		Double circuit 9M3/9M6 44kV feeders for Innisfil Hydro supply. Re-budgeted from 2007 budget. An assumed cost to Pay Hydro One for their works. No formal estimate received to date. These two feeders will provide future load growth as well as redundancy and back up for the other 44KV feeders in Innisfil.

ID	Total	Description	Category	Project Overview
CDP-7	$157,953	44kV Mechan-ized Altdi-Ruptor Scada	Reliability	Four (4) load break switches in total. Three of which are going to replace obsolete border point air break style switches and a fourth as a new switch put in the 44KV tap to Tempo and Siscor along Hwy 400. This will provide a fast isolation to the 44KV if salt damage or other problems should occur.
CDP-8	$126,497	27.6V Mech-anized Scada-mate swit	Reliability	Installation of 27.6 kV switches to provide redundancy back up feeds for the Town administration and Industrial Park areas. Mechanized 27.6kV Scada mate switches are replacing aged in-line style switches and shall be strategically placed where the solid in-line switches currently exist. This will assist in outage situations and faster restoration to the Industrial Park customers.
CDP-9	$ 0	Carried forward 9M3 9M6. *Re-Allocated to 2009*		New line construction to bring in the 9M3 and 9M6 from Hydro One - Carried forward from the 2007 Budget. Double circuit 44KV will be continued out of Hydro One's area (10 SR of Essa) south on County Rd. 27 to the 5th line of Innisfil east to the 5th Side Rd. These two feeders will provide future load growth as well as redundancy and back up for the other 44KV feeders in Innisfil.
CDP-10	$209,696	Pole Replace-ment	Infrastructure Replacement	Approximately 1/8th of Innisfil's Poles tested through the maintenance program. Pending a 4% failure rate an approximate of sixty (60) poles will need replacement.
CDP-12	$ 16,773	Meter Analyzer	Meter	To analyze new service connections and existing services for accuracy. IHDSL did not own an analyzer until this purchase, it is needed for 3 phase services.
CDP-13	$ 0	Wholesale Meters		Primary Metering Equipment for 2 new 44 kV feeders from the Alliston TS to supply Innisfil Hydro service area.
CDP-14	$55,296	Conventional Meters	Meter	To meter new services as they are energized prior to SMI implementation.
BASE	$592,970	Base	Customer Demand	Within the daily operations of Innisfil Hydro it is necessary to install, replace, relocate capital infrastructure that is not part of identified capital projects through the year. Examples such as vehicular accidents, storm damage replacement and issues identified by Hydro staff in the day to day operations go to this section of the capital budget. All overhead and underground servicing for customer request like new installs, upgrades, relocates and replacements impact the base budget and also receive contributions towards such works as outlined in the DSC.
TOTAL:	**1,872,817**			

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2008 General Plant

ID	Total	Description	Category	Project Overview
GB-003	$92,435	Portables 2	Facility	$60k - 2 portables, $20k carry forward from 2007.
GB-003	*Included above*	Stores	Facility	$5k - Renovate Stores washroom for boardroom meetings.
GB-003	*Included above*	Close in rear stores & refinish fence	Facility	$20k - Close in rear of stores and finish fence for protected storage and security.
GB-002	$11,402	Operations Offices	Facility	$2,000 Wade's office for space optimization. $1,500 Pete's office. $1,500 Stores Meeting room; Table, art $4,000 GM & CFO furniture; space optimization.
GB-002	*Included above*	Meeting Room Miscellaneous	Facility	Chair and desk for meeting and working with Lineperson supervisor.
GB-002	*Included above*	Letter Opener	Facility	$4,000 Letter opener; due to high maintenance cost.
GB-002	*Included above*	Portables-File cabinets/racks	Facility	$6,600 File cabinets & racks for portables; $5k for racks and $1.6k for 2 filing cabinets.
GF-002	$1,928	Wide screen monitors	Hardware & Software	2 wide screen monitors for viewing several spreadsheets at a time.
GB-001	$8,190	Network Printers-5	Hardware & Software	$7.5k Network printers-5 printers ranging in age from 3-14 years old.
GB-001	*Included above*	Bandwidth	Hardware & Software	$10k Increase bandwidth from 1 meg to 2 meg for increased volume of data flow.
GB-001	*Included above*	Workstations & Monitors	Hardware & Software	$13k Workstations & monitors-$3k stores flat screen.
GB-004	$35,487	Server & 2 Scanners	Hardware & Software	$30k North Star & MGP Servers- 2 servers required due to software upgrades.
GB-001	$80,194	Wireless Blackberry	Hardware & Software	$5k Wireless Blackberry access to provide more flexibility for network access.
GB-001	*Included*	Veritas	Hardware &	$5k Veritas upgrades (backup software).

	above	Upgrades	Software	
GB-001	*Included above*	North Star Upgrade Training	Hardware & Software	$7.5k North Star training-on-site during implementation and 'go live'.
GB-001	*Included above*	File nexus Annual License	Hardware & Software	$2.5k Annual unlimited web license fee for customer access to e-Care (view bills etc).
GB-001	*Included above*	Workstation Upgrades	Hardware & Software	$5k Workstation upgrades.
GB-001	*Included above*	Esri Upgrades for Toughbooks	Hardware & Software	$4k ESRI upgrades for Toughbooks.
GB-001	*Included above*	AutoCAD 2 Add'l Licenses & Upgrades	Hardware & Software	$16k AutoCAD 2 add'l licences & 2 upgrades.
GB-001	*Included above*	GP Fixed Asset Module	Hardware & Software	$12k Great Plains & Wennsoft licences-2 add'l license for increase user use.
GH-001		HR Module	Hardware & Software	Improve recording and reporting of human resources and payroll information. Expand reporting capabilities to include sick days, vacation, etc.
GB-004		Scan Station Licenses	Hardware & Software	One new server and two additional scanners, plus one additional scan station licence to increase the capacity and use of electronic archival system, improve efficiency of data access and reduce the use of paper and need for additional filing cabinets.
GO-002	$28,507	Vehicle	Transport	New vehicle issue of a half battery, half gas hybrid SUV to a field engineering technician which will replace a 1999 Astro with 201530 km which is in turn replacing a 1998 Transport with 199643 km. The Astro will be used as a secondary vehicle for student and vehicle in repair use. The 1998 Transport will be sent to auction.
GO-003	$3,431	Stores Equip.	Tools	Wire racking solution for inventory control will assist the stockkeeper in faster service for line crews while ensuring accurate measurements of wire. This will also lift all the copper reels currently off the floor onto the rack. Better use of limited space as well as better labelling for issue are some of the benefits.
GO-004	$9,467	Tools, Shop &	Tools	Shelving and racking solution for outside stored materials will move inventoried

		Garage Equip.		material up off ground locations while organizing and securing these items. Purchase of a trash pump that is commonly needed to assist wet pole installations. Miscellaneous tool replacement as needed and justified.
GO-005	$1,927	Measurement & Testing Equip.	Tools	Replacement and additional wide band digital meters for high accuracy at low amperages required for reading amperages under 1 amp. Replacement of electronic devices as needed and justified.
GO-001	$ 0	27.6kV Radio Repeated Fault Indicators - *Deferred*	Communica-tion	Radio controlled fault indicators to assist new Scada mate switching. Three sets required for diagnosing and monitoring fault currents through the 27600 volt distribution system for reliability and faster problem identification shorting outage restoration.
GO-006	$ 0	Scada Programming & Updates, Battery - *Deferred*	Communica-tion	Scada programming and updates for existing and future needs. A new 27.6 kv fault and switching screen will need to be added to the main SCADA program server. Some lead acid battery replacement to gelled battery as required.
TOTAL:	**$272,968**			

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2009 Capital Projects by Category & Cost

Projects	Category	Cost
2009 Distribution Plant		
DO-001 Pole Replacement	Infrastructure Replacement	257,033
DO-002 44kv load interruptors	Reliability	255,043
DO-003 Transformer Replacement	Infrastructure Replacement	67,421
DO-004 9M4 extension-20 SR 10th Ln & Lockhart rd	Security	136,224
DO-005 Recloser automation & replacement	Reliability	84,062
DO-007 27.6 SCADA mates	Reliability	136,546
DO-008 44 kV line ext 20th SR Lockhart to Fairway Rd	Capacity	424,900
DO-010 Wholesale meters	Meter	61,125
DO-011 Guard Rails	Reliability	41,065
DO-012 Urbanization	Customer Demand	1,186,136
DO-015 Infrastructure betterments	Infrastructure Replacement	147,760
DO -017 Line Extension	Reliability	656,280
Base	Customer Demand	293,604
Meter Disposals	Meter	-1,270,515
Sub-Total		**2,476,684**
2009 General Plant		
GB-008 - Network Upgrades, Servers, Workstations	Hardware & Software	88,448
Miscellaneous		**257,438**
Sub-Total		**345,886**
2009 Grand Total		**2,822,570**

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2009 Project Costs by Category

Category	Cost
Infrastructure Replacement	472,214
Reliability	1,172,996
Security	136,224
Capacity	424,900
Meter	-1,209,390
Customer Demand	1,479,740
Hardware $ Software	0
Miscellaneous Genral Plant	88,448
2009 Grand Total	**2,565,132**

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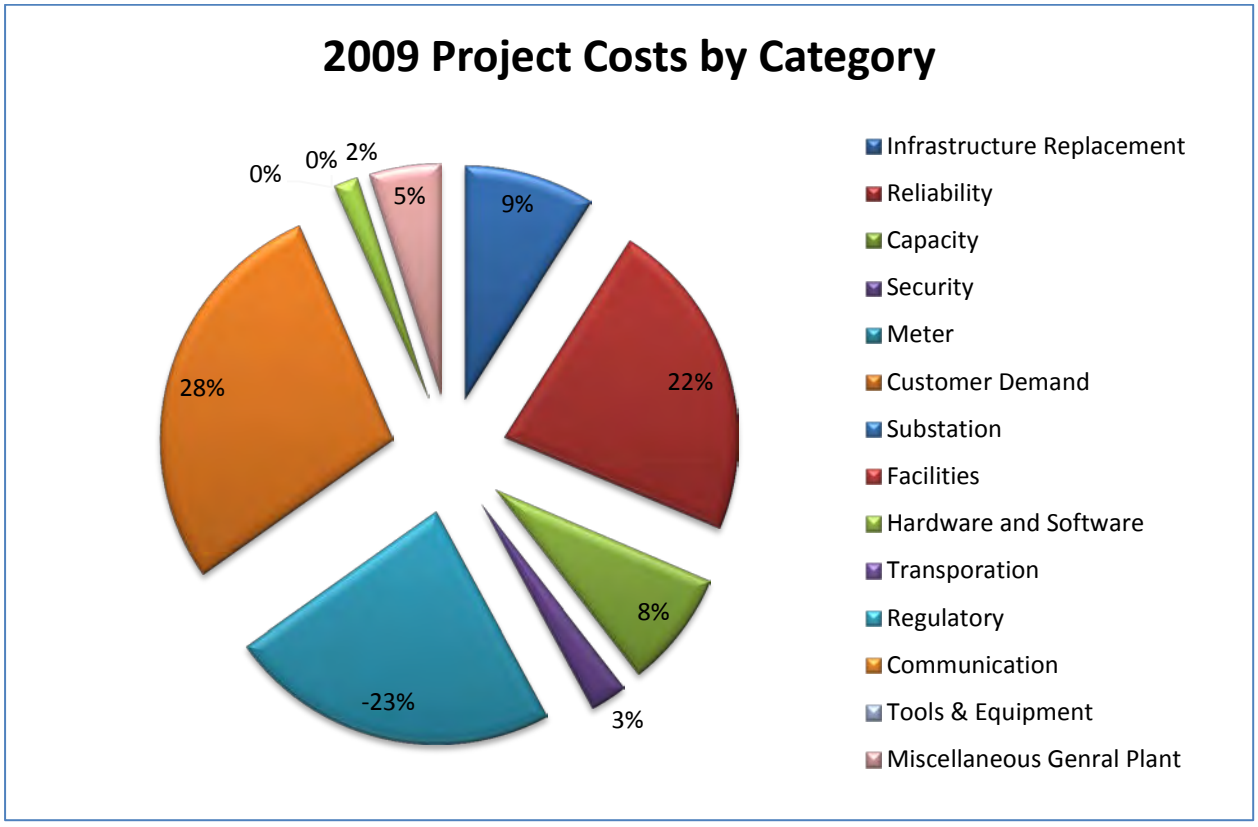

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2009 Capital Project Summary

2009 Distribution Plant

ID	Total	Description	Category	Project Overview
DO-001	$257,033	Pole Replacement	Infrastructure Replacement	Approximately 1/8th of Innisfil Hydro's poles will be tested through its min program pending approximately 4% failure rate. An estimated sixty (60) poles will need to be replaced.
DO-002	$255,043	44kV Load Interruptors	Reliability	Four (4) switches in total. Each of these switches shall replace an aging and obsolete current airbreak or MSO location. These switches are designed utilizing SCADA technology to faster isolate faulted locations in the 44kV subtransmission system.
DO-003	$67,421	Industrial Park Transformer Replacement	Infrastructure Replacement	Due to salt contamination along Hwy. 400 the transformers and other apparatus are beginning to decay at an accelerated rate. The deteriorating transformers will be replaced with stainless steel tanks and have zinc rich coated primer to assist in the long term use of the asset.
DO-004	$136,224	9M4 extension-20 SR 10th Ln Lockhart Rd.	Security	This 44kV line extension is designed to allow the backup of the recently completed 13M3 extension with the 9M4. Besides having the capability to back up the Barrie 13M3 at this location it will also have the future potential for dividing loads, pending the two (2) new incoming feeders from Alliston.
DO-005	$84,062	Recloser Automation & Replacement	Reliability	Two (2) sets of Cooper Kyle Nova electronically controlled reclosers are to be added to the distribution system. These low maintenance units utilize vacuum break technologies rather than hydraulic oil versions. This dramatically reduces the cost of maintenance over the long term of the asset. These units are also automated using SCADA technology to isolate or restore in outage conditions greatly improving restoration time as well as reducing line staff time. The second part of this request is ongoing maintenance replacement of hydraulically operated reclosers in the distribution system.
DO-006	$ 0	Utility Relocates - *Deferred*		In an e-mail to Innisfil Hydro staff, the County of Simcoe has indicated construction in five (5) designated areas of Innisfil. These works range from road widenings to traffic signal installations. The County draft proposals indicate that the majority of the work is to commence in 2009. One (1) draft plan viewed in November 2007 has a large scope of work including relocating multiple spans of

ID	Total	Description	Category	Project Overview
				the double circuited 44000 subtransmission with two (2) locations having 44kV mechanized load Interruptors.
DO-007	$136,546	27.6 Scada Mates	Reliability	Three (3) mechanized 27/600 volt Scada mate switches are to be installed into Innisfil Hydro's distribution system. These switches will be strategically placed where solid in-line switches currently exist and this will assist in outage situations and faster restoration to the Industrial Park customers.
DO-008	$424,900	44kV Line Extension- 20th SR Lockhart to Fairway	Capacity	This project is the continuation of the Barrie 13M3 line extension in 2008 that will eliminate the radical feed and serve as a loop fed system to the Kempenfelt Centre and Big Bay Point Distribution Station. These works consist of all stringing conductors and switching components to complete the project.
DO-010	$61,125	Wholesale Meters	Meter	44kV metering unit required for new 9M2 subtransmission Circuit from H1 at IHDSL border location.
DO-011	$41,066	Guard Rails	Reliability	New guard rails around rural 44kV motor operated switches will help protect Innisfil Hydro's investments on a single pole. Strategic locations in rural environments will be selected to keep safe the motor mechanism, pole and switch at the top, ensuring protection while also protecting from a prolonged outage should the pole be hit.
DO-012	$1,186,136	Urbanization	Customer Demand	The Town of Innisfil initiated a road widening and underground urbanization of Innisfil Beach Road Precinct two (2b). All overhead lines and distribution assets will be relocated and converted to underground infrastructure in this section. Electrical design and installation based off engineered plans developed and supplied by Town of Innisfil engineering department.
DO-013	$ 0	27kV Voltage Conversion 20 SR 5th & 6th Ln- *Deferred*	Infrastructure Replacement	Innisfil Hydro can take advantage of the new 27/6 kV circuit to Lefroy and reduce some line losses on the 5th &6th Concessions of Innisfil by converting some radial single phase feeds from 4800 to 16000 volts.
DO-014	$ 0	27kV Voltage Conversion 20 SR 5th & 6th Ln- *re-*	Capacity	Line extension of the 27/6kV distribution system to accommodate the LSAMI development in Lefroy. 27/6 circuit required to service the development as the current Lefroy 8320 volt station is near capacity. This will also provide redundant back up feed between Brian Wilson DS and a new 44kV 227/6 station

ID	Total	Description	Category	Project Overview
		Allocated to 2014		in the near future. Innisfil Hydro will also benefit from replacing the aged infrastructure and assets with new assets in the distribution system.
DO-015	$147,760	Infrastructure Betterments	Infrastructure Replacement	Infrastructure betterments to commence in 2009: - replacement of offshore defective porcelain switches. - suspect porcelain 44kV bells in the subtransmission. - replacement of porcelain dead end bells in the distribution system. - old decayed secondary buss replacement.
DO-016	$ 0	Hydro One Contribution-*Deferred*	Reliability	Double circuit 9M3/9M6 44kV feeders for Innisfil Hydro supply. Re-budgeted from 2007 budget. An assumed cost to Pay Hydro One for their works. No formal estimate received to date. These two feeders will provide future load growth as well as redundancy and back up for the other 44KV feeders in Innisfil.
DO-017	$656,280	Line Extension	Reliability	New line construction to bring in the 9M3 and 9M6 from Hydro One –Re-budgeted from the 2007 Budget. Single circuit 44KV will be continued out of Hydro One's area (10 SR of Essa) south on County Rd. 27 to the 5th line of Innisfil east to the 5th Side Rd. This feeder will provide future load growth as well as redundancy and back up for the other 44KV feeders in Innisfil.
Base2009	$293,604	Base	Customer Demand/ Infrastructure Replacement	Within the daily operations of Innisfil Hydro it is necessary to install, replace, relocate capital infrastructure that is not part of identified capital projects through the year. Examples such as vehicular accidents, storm damage replacement and issues identified by Hydro staff in the day to day operations go to this section of the capital budget. All overhead and underground servicing for customer request like new installs, upgrades, relocates and replacements impact the base budget and also receive contributions towards such works as outlined in the DSC.
	-$1,270,515	Meter Disposals	Substation	Smart Meter deployment and disposal.
TOTAL:	**$2,476,683**			

2009 General Plant

ID	Total	Description	Category	Project Overview
GB-011	$14,296	Office Furniture	Facility	Refurbish exterior of administration buildings. Upgrade computer room air conditioner. Replace windows. Line office modifications in Stores building.
GB-007	$12,117	AutoCAD Toughbook	Hardware & Software	AutoCAD Topobase electric 2 workstations and 1 administrator to enhance inter-usability of data both across the organization and with third parties, eg Town GIS. Adding a third 'tough book" for field work. WESys full WO integration with MGP
GB-009	$41825	Backup & Printers	Hardware & Software	Network related: upgrade back-up infrastructure, add printers Server related: server upgrades and add redundancy Workstation related: Add and replace workstations and monitors
GB-008	$88,448	Annual Upgrades to Network, Services	Hardware & Software	Network related: advanced weather detection and radar software firewall upgrades. (3000 for weather detection) Server related: operating system, PDF and sql upgrades/renewals Workstation Related: workstation Microsoft upgrades
GB-010	$3,151	Microsoft Great Plains Upgrades	Hardware & Software	Upgrade to latest version of Microsoft Great Plains to ensure continued support from Microsoft.
GO-002	$83,273	Vehicle-2	Transport	Vehicle replacement required for two (2) 10 year old vehicles. Both are 1999 Astor's with approximately 210,000 km and 205,000 km.
GO-003	$ 0	Stores Equipment	Tools	Miscellaneous solutions will include better use of limited space for inventory control and it will assist the stock-keeper in faster service for the line crews.
GO-004	$6,190	Tools, Shop & Garage Equip.	Tools	Miscellaneous solutions for stored materials both inside and outside secured locations. Miscellaneous tool replacement as needed and justified.
GO-005	$6,064	Measurement & Testing Equip.	Tools	Road distance measuring device installed in the technician's vehicle to assist with span distances on capital betterments. Replacement of electronic devices as needed and justified.
GO-001	$33,609	27.6 V Radio Repeated	Communication	Radio controlled fault indicators to assist new Scada mate switching. Three (3) sets required for diagnosing and monitoring

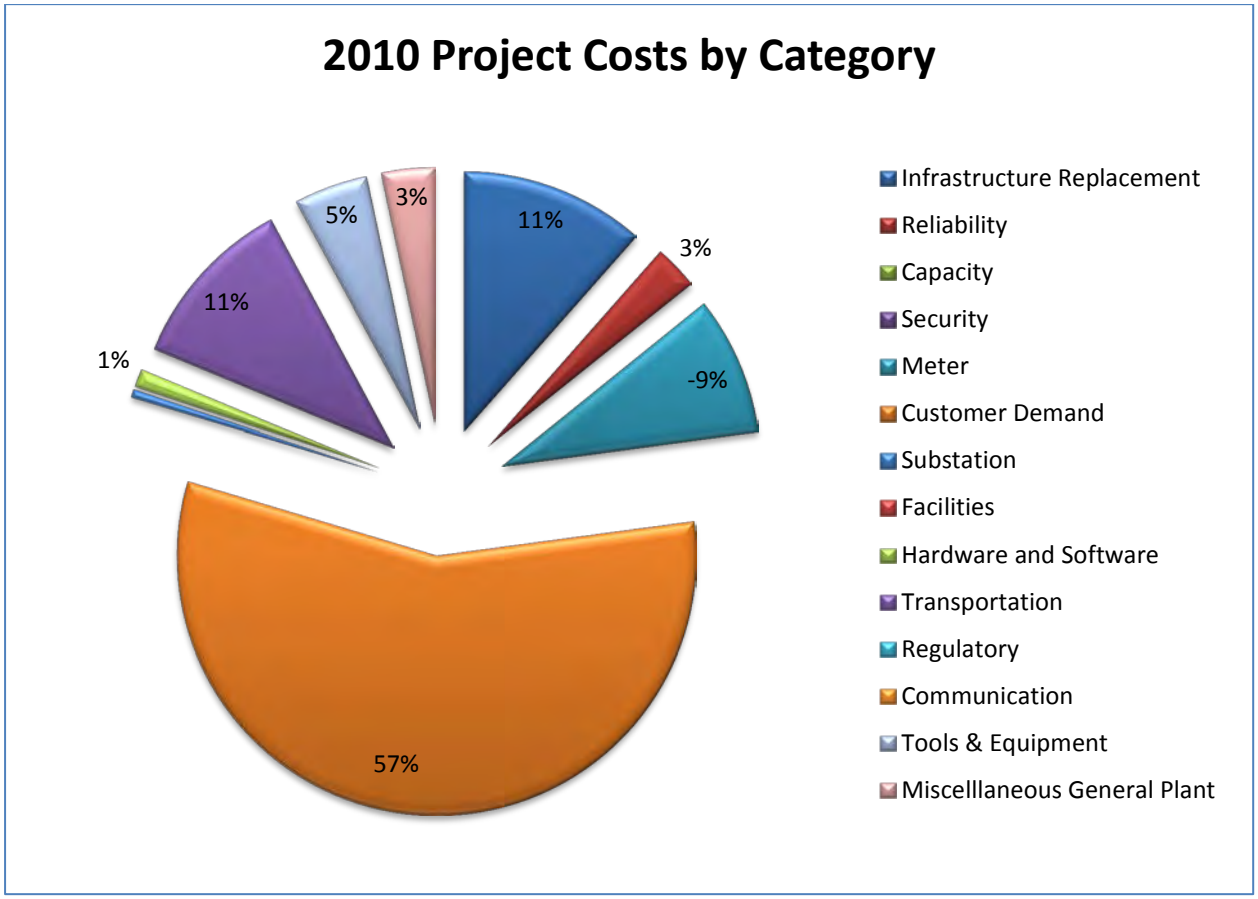
ID	Total	Description	Category	Project Overview
		Fault Indicators		fault currents through the 27/600 volt distribution systems for reliability and faster problem identification shorting outage restoration.
TOTAL:	**$345,886**			

2010 Capital Projects

Projects	Category	2010
2010 Distribution Plant		
DO-006- 20th SR & 7th line extension		
DO-008 - Urbanization Precinct 1	Customer Demand	323,380
DO-010 - Pole replacement	Customer Demand	310,760
DO-011-Replace porcelain swirches	Reliability	157,558
DO-015- DS oil re-inhibit treatment	Substation	12,207
DO-016 - Replace coiling fans Tempo plastics	Substation	17,205
DO-017 Substandard Transformer	Infrastructure Replacement	110,257
DO-018 - Urbanization Precinct 2a & 3	Customer Demand	1,662,944
DO-019- Urbanization Precinct 3	Customer Demand	670,000
DO-020 - 20th SR & 6th Line extension	Infrastructure Replacement	546,690
Base	Customer Demand	272,872
Meter Disposals	Meter	-492,071
Sub-Total		**3,591,802**
2010 General Plant		
GB-001 Network upgrades and redundancy servers	Hardware & Software	64,210
GO-010 Fleet trucks	Transport	621,180
GO-008 Fleet tools	Tools	260,656
Miscellaneous		188,227
Sub-Total		**1,134,273**
2010 Grand Total		**4,726,075**

2010 Project Costs by Category

Category	Cost
Infrastructure Replacement	656,947
Reliability	157,558
Security	0
Substation	29,412
Meter	-492,071
Customer Demand	3,239,956
Transport	621,180
Tools	260,656
Hardware & Software	64,210
Miscelllaneous	188,227
2009 Grand Total	**4,726,075**



2010 Capital Project Summary

2010 Distribution Plant

ID	Total	Description	Category	Project Overview
DO-006	$ 0	20th SR & 7th Ln Ext- *Re-Allocated to 2012*	Customer Demand	The City. Of Simcoe has advised they will be commencing intersection construction @ two (2) locations in 2010. One of which is 20th S.R. @ the 7th Line of Innisfil. Innisfil Hydro must move approximately thirty (30) spans of44kV subtransmission and 27.6 kV 3 phase and 1 phase circuits at this intersection to meet the County requirements.
DO-007	$ 0	Hwy 89 & 10 SR Widening- *Re-Allocated to 2011*	Customer Demand	The County of Simcoe advised they will be commencing intersection construction at two (2) locations in 2010, one being Hwy. 89 & 10 Sideroad. Innisfil Hydro must relocate approximately thirty (30) spans of single CCT subtransmission 44kV & 4800 V Distribution to accommodate County works.
DO-008	$323,380	Urbanization Precinct #1	Customer Demand	The Town of Innisfil initiated a road widening and underground urbanization of Innisfil Beach Road. In Precinct one (1), all overhead lines and distribution assets will be relocated in this section. Electrical design and installation based off engineered plans developed and supplied by Town of Innisfil engineering department.
DO-010	$310,760	Pole Replacement	Customer Demand	Assume replacing seventy (70) poles. Twenty (20) poles with live three (3) phase - no transformer. Twenty (20) poles with live one (1) phase - no transformer. Fifteen (15) poles with live three (3) phase with transformer. Fifteen (15) poles with live one (1) phase with transformer.
DO-011	$157,558	Infrastructure Betterments	Infrastructure Replacement	Infrastructure Betterments to commence in 2010 are as follows: Replace suspect defective porcelain switches. Replacement of porcelain dead end bells within distribution system. Secondary Buss replacement. Replace rotting cross arms. Replace defective in-line 44kV switches.
DO-015	$12,207	DS Oil Re-Inhibit Treatment	Substation	Annual testing of transformer oil at Innisfil DS indicates oil quality properties and dissolved gasses are within acceptable limits, however, the oxidation inhibitor is depleted. The oil re-inhibit treatment will deter oil oxidation, thereby, extending the serviceable life of the mineral oil and the reliable life of the transformer.
DO-016	$17,205	Replacement Colling Fins at	Substation	The cooling fins on the IHDSL owned transformer at Tempo Plastics are rusting badly. Due to the thin metal of the fins; skin, sanding and re-painting

ID	Total	Description	Category	Project Overview
		Tempo Plastic		is not an option for repair. Replacing the cooling fins with new galvanized steel high efficiency fins will greatly extend the transformer life. The galvanized steel will also be much more durable and less prone to rust caused by salt from the adjacent 400 Highway.
DO-017	$ 110,257	Substandard Transformer Re-Habs	Infrastructure Replacement	To address the aging and substandard transformer installations where the transformer is installed below the secondary buss. This method of framing was common practice in earlier years of construction to conserve on pole height. These installations now pose a clearance and subsequent safety risk to staff and the public while working on a nd or in the vicinity of these installations.
DO-018	$1,662,944	Urbanization Precinct 2a	Customer Demand	The Town of Innisfil initiated a road widening and underground urbanization of Innisfil Beach Road Precinct two (2a). All overhead lines and distribution assets will be relocated and converted to underground infrastructure in this section. Electrical design and installation based off engineered plans developed and supplied by Town of Innisfil engineering department.
DO-019	$ 670,000	Urbanization Precinct 3	Customer Demand	The Town of Innisfil initiated a road widening and underground urbanization of Innisfil Beach Road Precinct three (3). All overhead lines and distribution assets will be relocated and converted to underground infrastructure in this section. Electrical design and installation based off engineered plans developed and supplied by Town of Innisfil engineering department.
DO-020	$546,690	20th SR & 6th Ln Extension	Infrastructure Replacement	With the conversion of Alcona to 27.6 kV and subsequent removal of Alcona Distribution Station (D.S.) in 2006; Cedar Point D.S. has only one (1) feeder out of Lefroy D.S. to back it up. This project will extend a 2nd Lefroy D.S. feeder N on the 20th S.R. east on the 6th Line to back up Cedar Point Station during maintenance or emergency.
DB-002	$ 0	Retail Meters	Meter	Purchase single and three phase meters for new services.
DB-003	$-492,071	Stranded Meters	Meter	Smart Meter deployment and disposal.
Base2010	$272,872	Base	Customer Demand	Within the daily operations of Innisfil Hydro it is necessary to install, replace, relocate capital infrastructure that is not part of identified capital projects through the year. Examples such as v ehicular accidents, storm damage replacement and issues identified by Hydro staff in the day to day operations

ID	Total	Description	Category	Project Overview
				go to this section of the capital budget. All overhead and underground servicing for customer request like new installs, upgrades, relocates and replacements impact the base budget and also receive contributions towards such works as outlined in the DSC.
TOTAL:	**3,591,803**			

2010 General Plant

ID	Total	Description	Category	Project Overview
GB-006	$34,836	Building and Fixtures	Facility	Maintain healthy and efficient work environment (including 5000 for line office additions-lockers, drying areas, foreman's office).
GB-007	$21,306	Office Furniture	Facility	Replace existing workstations with more ergonomically correct designs and add workstations for new staff. (5100 for 2 new staff - Eng).
GB-001	$64,210	Upgrades & Redundancy Server & Works	Hardware & Software	Upgrades to IT Infrastructure-Network, Servers, Peripherals, including workstations.
GB-002	$47,687	Network and Server Upgrades	Hardware & Software	General Software upgrades to improve security and operating efficiency of network.
GB-003		North Star Upgrade	Hardware & Software	Update to version that is currently being enhanced and developed for Ontario market.
GB-004	$ 0	Wesys Estimates Integrated into GP - deferred	Hardware & Software	Version 11 upgrade to implement IFRS.
GB-005	$ 0	Autodesk Integration	Hardware & Software	Continue integration of AutoDesk 3D-Topo and ASI apps to gain efficiencies in Engineering.
GO-010	$621,180	Fleet Trucks	Transport	Purchase of Line vehicles to support the internalization of 5 Line personnel. 1-double bucket, 1-single bucket, 1-Rotary Boom Derrick, Pickup truck and 1-fleet replacement of 2000 Chev with more than 250,000KM.

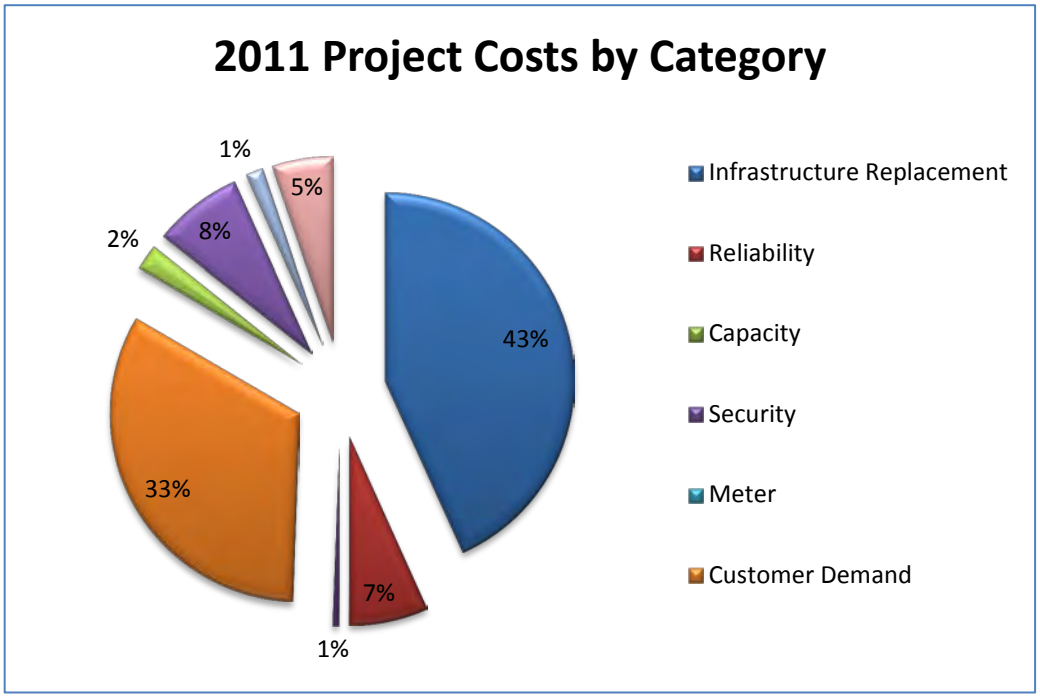
ID	Total	Description	Category	Project Overview
GO-016	$ 0	Stores Equipment	Facility	Miscellaneous solutions will include better use of limited space for inventory control and it will assist the stock-keeper in faster service for the line crews.
GO-008	$260,656	Fleet Tools	Tools	Purchase of Line tools to support the internalization of 5 L ine personnel. Vehicle tools to outfit and support Line trucks and personnel, pole and wire trailer.
GO-009	$40,149	Flagging Signalers	Tools	1 pair of flagging stop and go lights with stop arm for oncoming traffic control. Reduces the use of flagging personnel.
GO-017	$4,358	Tools, Shop & Garage Equip.	Tools	Miscellaneous solutions for stored materials both inside and outside secured locations. Miscellaneous tool replacement as needed and justified.
GO-018	$ 0	Measurement & Testing Base		Replacement of electronic devices as needed and justified.
GO-013	$18,900	27.6kV Radio Repeated Fault Indicators	Reliability	Radio controlled fault indicators to assist new Scada Mate switching. Three (3) sets required for diagnosing and monitoring fault currents through the 27/600 volt distribution systems for reliability and faster problem identification shorting outage restoration.
GO-014	$20,991	System Supervisory	Tools	Implementation of new fault indicating and switching devices in the distribution system. Solution for communications from repeater locations to Innisfil Hydro office and some lead acid battery replacement to gelled batteries as required.
TOTAL	**$1,134,273**			

2011 Capital Projects

Projects	Category	2011
2011 Distibution Plant		
DO-001 Hwy 89 reconductoring (5th SDRD to Younge ST)	Infrastructure Replacement	200,328
DO-002 Leonards Beach Major Betterment	Reliability	264,262
DO_003 20th SD RD/10th Line extension	Infrastructure Replacement	285,119
DO-006 Reclosurer refurbishments	Infrastructure Replacement	160,715
DO-007 Pole replacement	Infrastructure Replacement	254,297
DO-008 Infrastructure betterments	Infrastructure Replacement	104,256
DO-009 30th line extension &44kv reconductoring	Infrastructure Replacement	567,331
DO-010 Substation security	Security	20,030
DO-011 Hwy 89 & 10SDRD road widening	Customer Demand	277,241
DO-013 Padmount transformer replacements	Infrastructure Replacement	45,082
DO-014 Substandard transformer re-habs	Infrastructure Replacement	67,521
DO-015 IBR URB precinct 1	Customer Demand	41,358
DO-016 IBR URB precinct 2a teardown	Customer Demand	229,232
Storms	Customer Demand	115,257
Economic evaluation - Woodland Park	Customer Demand	207,565
Base	Customer Demand	410,360
Sub-Total		**3,249,953**
2011 General Plant		
GB-001 Network upgrades and Hardware	Hardware &Software	86,927
GO-007 Fleet Trucks	Transport	297,131
GO-008 Fleet tools	Tools	58,448
Miscellaneous	Miscellaneous	201,860
Sub-Total		**644,366**
2011 Grand Total		**3,894,319**

2011 Project Costs by Category

Category	Cost
Infrastructure Replacement	1,684,649
Reliability	264,262
Security	20,030
Substation	0
Meter	0
Customer Demand	1,281,013
Transport	297,131
Tools	58,448
Hardware & Software	86,927
Miscelllaneous	201,860
2009 Grand Total	**3,894,319**



2011 Capital Project Summary

2011 Distribution Plant

ID	Total	Description	Category	Project Overview
DO-001	$200,328	Hwy 89 Reconductoring 5 SR to Yonge St	Infrastructure Replacement	With the new Alliston 9M2 44kV CCT now available reconductoring this section will provide redundancy for the 9M1, 9M4 & 13M3. The existing 336 mcm conductor is not sized large enough to carry all of the possible ampacity load. Increasing the conductor to 556 mcm maximizes the usage of the new Alliston 9M2 CCT in the occurrence where it is required to back up the other 44kV CCT's.
DO-002	$264,262	Leonard's Beach Major Bettlement	Reliability	The existing tie line from the 9th Line along Leonard's Beach Road to the 10th Line consists of 2 phase from the 9th Line to Rose Lane, and 1 phase from Rose Lane to the 10th Line. This project upgrades the line to 3 phase which provides another back up source for the McKee Subdivision, Ireton and Purvis Street areas and any future development north of these locations.
DO-003	$285,119	20th SR/10th Ln Extension	Infrastructure Replacement	At present the Brian Wilson F1 extends north on the 25th Sideroad to feed east on the 10th Line into the McKee Subdivision, Purvis Street, Ireton areas. There is no back up should the main line go down along the 25th Sideroad. This line extension will provide a 3-phase backup for this area and will be part of a future backbone for a smart grid/self-healing system in the northern Alcona area.
DO-004	$ 0	27.6 Scada Mate Switches-*Re-allocated to 2012*		Three (3) mechanized 27/600 volt Scada Mate switches are to be installed into Innisfil Hydro's distribution system. These switches will be strategically placed where solid in-line switches currently exist. This will provide remote switching capability and real time data acquisition to better manage outage reporting numbers to the OEB. Crew time will be reduced during emergency and non-emergency operations and built in functionality can be used for future smart grid, self healing considerations.
DO-005	$ 0	44kV Load Interruptor Switches- *Re-allocated to 2012*		Four (4) switches in total. Each of these switches shall replace an aging and obsolete current airbreak or MSO location. Each will provide remote switching capability and real time data acquisition to better manage outage reporting numbers to the OEB. Crew time will be reduced during emergency and non-emergency operations and built in functionality can be used for future smart grid, self-healing considerations within the 44kV subtransmission system.

ID	Total	Description	Category	Project Overview
DO-006	$160,715	Recloser Refurbishments	Infrastructure Replacement	Two (2) sets of G&W electronically controlled reclosers are to replace the Leonards Bch. D.S. hydraulic reclosers. These low maintenance units utilize vacuum break technologies rather than hydraulic oil versions. This technology dramatically reduces the cost of maintenance over the life of the asset. These units will be providing remote communication via the SCADA network which improves the efficiencies and restoration times during outages and allows recording of momentary and operational data. The electronic reclosers play a compulsory role in the Self healing, smart grid system of the future. Also as part of the project, costs for refurbishment of reclosers due in the 4 year cycle rotation.
DO-007	$254,297	Pole Replacement	Infrastructure Replacement	Assume replacing seventy (70) poles. Twenty (20) poles with live three (3) phase - no transformer. Twenty (20) poles with live one (1) phase - no transformer. Fifteen (15) poles with live three (3) phase with transformer. Fifteen (15) poles with live one (1) phase with transformer.
DO-008	$104,256	Infrastructure Bettlements	Infrastructure Replacement	Infrastructure Betterments to commence in 2011 are as follows: Replace suspect defective porcelain switches. Replacement of porcelain dead end bells within distribution system. Secondary buss replacement. Replace rotting cross arms. Replace defective in-line 44kV switches.
DO-009	$567,331	3/0 Ln Ext & 44kV Reconductoring 6th to 7th Line delayed	Infrastructure Replacement	A pole and conductor replacement is necessary on 20th SR, from 6th line to 7th line. This is the final piece to create a 27.6kV tie between the Brian Wilson D.S. and new 27.6kV Lefroy D.S. An upgrade of the existing 44kV circuit from 336 MCM to 556 MCM conductor will also occur to maximize the feeder capability of 600 amps. Without this section of line the new Lefroy Station will be islanded without redundancy in an emergency or for maintenance.
DO-010	$20,030	Substation Security	Security	Due to the increase of break-ins at our distributions stations, and the subsequent potential for property damage and personal injury, we are planning to install alarm systems in each station. The alarm signal will be transmitted via existing SCADA infrastructures to notify on-call operations staff.
DO-011	$277,241	Hwy 89 & 10 SR City Road Widening	Customer Demand	Originally the Cty. of Simcoe has advised they will be commencing intersection construction at two (2) locations in 2010. Both had been delayed due to property acquisitions. County approval occurred in 2011 for Hwy. 89 & 10 S.R. Innisfil Hydro must relocate approximately thirty (30) spans of single CCT

ID	Total	Description	Category	Project Overview
				subtransmission 44kV and 8320V distribution to accommodate County works.
DO-012	$ 0	7th Ln 20th SR City Road Relocate-*Re-allocated to 2012*		The Cty. Of Simcoe has advised they will be commencing intersection construction @ two (2) locations in 2010. One of which is 20th S.R. @ the 7th Line of Innisfil. Innisfil Hydro must move approximately thirty (30) spans of 44kV subtransmission and 27.6 kV circuits at this intersection to meet the County requirements.
DO-013	$45,082	Padmount Transformer Replacements	Infrastructure Replacement	Staff have noticed certain padmount transformers are starting to rust beyond the point of normal repair and painting. To ensure deteriorating padmount transformers do not pose a safety or environmental risk, a program to identify and replace these transformers shall be established and required year over year to mitigate corrosion from road salt, weather elements and manufacture defect.
DO-014	$67,521	Substandard Transformer Rehabs	Infrastructure Replacement	To address the aging and sub-standard transformer installations where the transformer is installed below the secondary buss. This method of framing was common practice in earlier years of construction to conserve on pole height. These installations now pose a clearance, and subsequent safety risk to staff and the public, while working on or in the vicinity of these installations.
DO-015	$41,358	IBR URB Precinct 1	Customer Demand	Due to the delays with the County of Simcoe obtaining property at the corner of Innisfil Bch.Rd. and the 20th Sideroad, pole works from 20th Sideroad and Innisfil Bch. Rd. intersection must be completed in 2011.
DO-016	$229,232	IBR URB Precinct 2a Teardown	Customer Demand	Finalization of Precinct 2A Urbanization project cannot occur until permanent street lights are installed at which time remaining poles and wires can be removed.
DO-017	$ 0	IBR URB Precinct 2a Street Lights		Final Street light installation under the RB Somerville contract will be in 2011 for Precinct 2A of the Innisfil Beach Rd. Urbanization project. A mount includes engineering costs for ETSS.
DB-002	$ 0	Retail Meters		Maintain adequate supply of retail single and three phase meters.
	$115,257	Storms	Customer Demand	Miscellaneous capital works directly pertaining to storm damage replacement of assets and infrastructure.
	$207,565	Economic Evaluation-Woodland Pk	Customer Demand	Capital costs paid out to developers for the transfer of developer supplied infrastructure in residential subdivisions

ID	Total	Description	Category	Project Overview
	$410,360	Base	Customer Demand	Within the daily operations of Innisfil Hydro it is necessary to install, replace, relocate capital infrastructure that is not part of identified capital projects through the year. Examples such as vehicular accidents, storm damage replacement and issues identified by Hydro staff in the day to day operations go to this section of the capital budget. All overhead and underground servicing for customer request like new installs, upgrades, relocates and replacements impact the base budget and also receive contributions towards such works as outlined in the DSC.
TOTAL:	**3,249,953**			

2011 General Plant

ID	Total	Description	Category	Project Overview
GB-005	$1,791	Buildings & Fixtures	Facility	Maintain healthy and efficient work environment.
GO-005	$1,200	New Building	Facility	Maintain healthy and efficient work environment.
GB-006	$16,042	Furniture & Equipment	Facility	Replace existing workstations with more ergonomically correct designs and add workstations for new staff. (2800 CDM)
GB-001	$86,927	Hardware General	Hardware & Software	Maintain security, maximize efficiency of IT Network Infrastructure including upgrades to servers, workstations and networked peripherals; add new back up tape drive.
GB-002	$6,255	General Network & Server Upgrades	Hardware & Software	General Software upgrades to improve security and operating efficiency of network.
GB-003	$ 0	North Star Upgrade	Hardware & Software	Update to version that is currently being enhanced and developed for Ontario market.
GB-004	$34,208	Teleworks IVR	Hardware & Software	To provide enhanced functionality for the provision of data for RRR filings.
GF-001	$5,625	Great Plains Upgrade	Hardware & Software	Upgrade to most current version supported by MGP.

ID	Total	Description	Category	Project Overview
GH-001	$13,280	HR/Regulatory Compliance Tracking	Hardware & Software	Implementation of software for comprehensive governance, risk and compliance management tool capable of providing high-visibility enterprise compliance to the rules and regulation under which companies operate.
GO-006	$35,401	Topobase and CYME	Hardware & Software	Continue integration of AutoDesk 3D-Topo with ASI apps and Sensus AMI to gain efficiencies in Engineering and add CYME software for distribution system planning, analysis and Connection Impact Assessment (CIA) for Distributed Generation (DG).
GO-007	$297,131	Fleet Trucks	Transport	
GO-010	$1,706	Stores Equipment	Tools	Miscellaneous solutions will include better use of limited space for inventory control and it will assist the stock-keeper in faster service for the line crews.
GO-008	$58,448	Fleet Tools	Tools	Purchase of Line tools to support Line personnel and Vehicles
GO-011	$9,307	Measurement & Testing Tools-Base	Tools	Replacement of electronic devices as needed and justified.
GO-001	$17,874	Bob Deugo/BW Tap Changer	Tools	Switching in the Alcona area often requires tying together the 27.6kV between the T1 and T2 Distribution station transformers at the Brian Wilson D.S. Automation to assist voltage balancing from the SCADA will make it accessible remotely to monitor changes in voltage imbalance and switch Tap changers on and off creating efficiencies in switching and outage restoration.
GO-002	$10,880	Radio Repeat Fault Indicators	Tools	Radio controlled fault indicators to assist new Scada Mate switching. Three (3) sets required for diagnosing and monitoring fault currents through the 27/600/44kv volt distribution systems for reliability and faster problem identification shorting outage restoration.
GO-003	$16,546	System Supervisory New Fault Indicator & Switching	Tools	Implementation of new fault indicating and switching devices in the distribution system. Solution for communications from repeater locations to Innisfil Hydro office and some lead acid battery replacement to gelled batteries as required.
GO-004	$31,746	OPTO to DNP3 Communication Replacement	Tools	Conversion from the older OPTO communication system for the SCADA to the newer, industry standard DNP3 communication protocol. DNP3 utilizes a higher security language in Radio Frequency transmission.
TOTAL:	**$644,366**			

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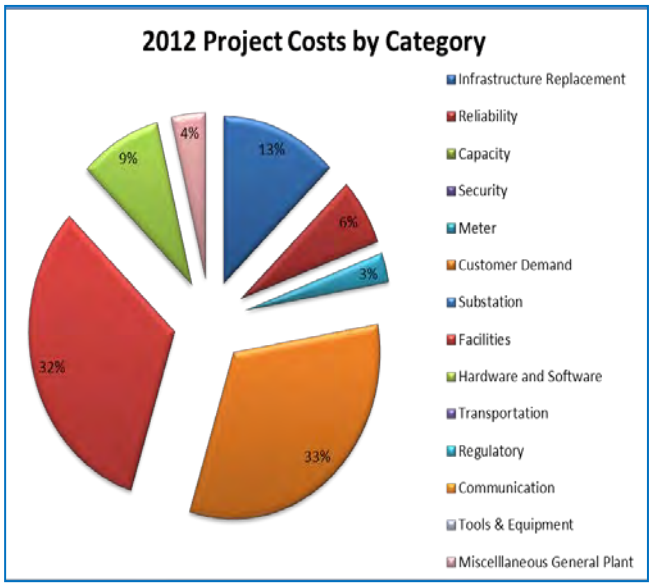
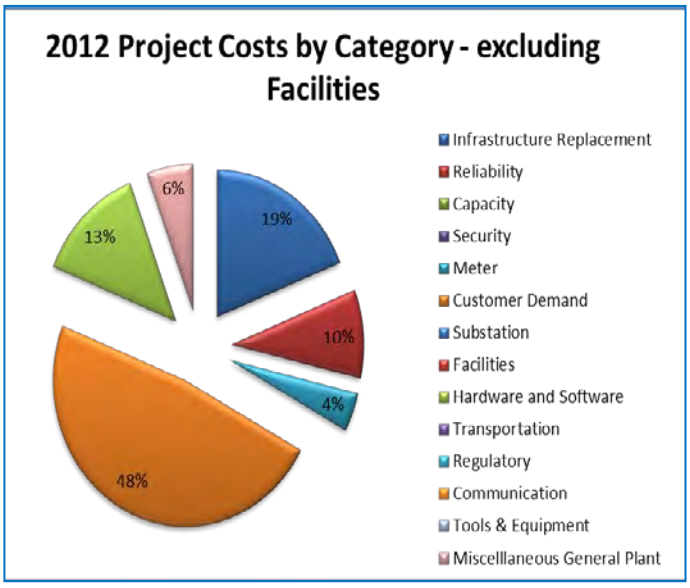
2012 Capital Projects

Projects	Category	2012
2012 Distribution Plant		
DO-005 - 2012 Pole Replacement Program	Infrastructure Replacement	389,270
DO-006 - Infrastructure Replacements	Infrastructure Replacement	166,850
DO-007- Reclosurer automation	Reliabilty	33,186
DO-009 - 27.6kv Mechanized SCADA Load Interpt	Reliability	157,808
DO-010 - 44kv Mechanized SCADA Load Interpt	Reliability	144,906
DO-012 - UG padmount TX replacements	Infrastructure Replacement	67,600
DO-013-Substandard trnasformer rehabs	Infrastructure Replacement	172,110
DO-015-County relocates IBR & 20th SDRD	Customer Demand	191,876
DO-016-County relocated 7th Line & 20th SDRD	Customer Demand	197,173
DO-017-County relocates IBR & 10th SDRD	Customer Demand	379,402
DO-018-Urbanization carry forward	Customer Demand	24,000
DO-019-Urbanization 2A lighting carryover	Customer Demand	154,850
DO-021-Cookstown water main relocates	Customer Demand	20,020
DO-022-TS Land	Customer Demand	465,000
DB-001- Retail meters	Meters	74,000
Base	Customer Demand	583,370
Smart Meter true up	Meters	11,384
Sub-Total		**3,232,805**
2012 General Plant		
GO-010 New Building	Facility	2,000,000
GB-001 Hardware &Software	Hardware & Software	193,000
GO-012 Eng topobase & IFRS enhancements	Hardware & Software	164,150
GO - 011 Scada program conversion	Hardware & Software	200,000
DO-009 27.6kv Scada controlled intercept	Reliability	68,700
Smart Meter true up	Meters	93,156
Miscellaneous	Miscellaneous	236,650
Sub-Total		2,955,656
2012 Grand Total		**6,188,461**

2012 Project Costs by Category

Category	Cost
Infrastructure Replacement	795,830
Reliability	404,600
Security	0
Substation	0
Meter	178,540
Customer Demand	2,015,691
Facility	2,000,000
Tools	0
Hardware & Software	557,150
Miscelllaneous	236,650
2009 Grand Total	**6,188,461**





2012 Capital Project Summary

2012 Distribution Plant

ID	Total	Description	Category	Project Overview
DO-002	$ 0	27.6kV Ln Ext 20th SR BBPT 13th to BBPT- *Re-allocated to 2013*	Customer Demand	Installation of a circuit of 27.6 kV (336 kcmil conductor) on 20th SR from 10th line to 13th line and E on 13th line from 20th SR to Fairway Rd. Previous projects have set the foundation for this project to link the Brian Wilson D.S. to a future 27.6 kV Station in Big Bay Point. Also in this scope will be the Installation of a 44 k V circuit (556 kcmil conductor) and 27.6 kV circuit (336 kcmil conductor) on 13th line, from Fairway Rd. to the intersection of 25th Sideroad just west of the south Entrance of the proposed BBPT development (Friday Harbour resort). Without this line, the future BBPT Station will be islanded without redundancy in an emergency or for maintenance.
DO-003	$ 0	3PH 27.6kV Conductoring on 20th SR b/w 5th & 7th - *Re-allocated to 2014*	Customer Demand	Installation of a circuit of 27.6 kV (336 kcmil conductor) on 20th SR, from 7th line to 5th line. Previous projects have set the foundation for this project to link the Brian Wilson D.S. to a future 27.6 kV Station in Lefroy. Without this line the new Lefroy Station will be islanded without redundancy in an emergency or for maintenance. Scope also includes the install of an approximate 10 poles (27.6 kV circuit) on 5th line, from 20th SR to new residential LSAMI entrance.
DO-004	$ 0	44kV Betterment 25 SR-*Re-allocated to 2017*	Infrastructure Replacement	In the scope of this project, a section of line between Mapleview Dr. and Lockhart Road on the 25th Sideroad has decayed poles with early signs of surface rot and feathering on pole tops. An approximate 25 poles of single circuit 44kV and single circuit 8.320kV will be replaced with the existing 336 k cml in the 44kV changed to 556 kcml to maximize the wire size to a full 600 amps current carrying capacity of the feeder.
DO-005	$389,270	2012 Pole Replacement Program	Infrastructure Replacement	Approximately 1/8th of Innisfil Hydro's poles will be tested through its testing program, with an anticipated 4% failure rate, an estimated 70 po les will be replaced. Twenty (20) poles with live three (3) phase - no transformer. Twenty (20) poles with live one (1) phase - no transformer. Fifteen (15) poles with live three (3) phase with transformer. Fifteen (15) poles with live one (1) phase with transformer.
DO-006	$166,850	Infrastructure Replacement &	Infrastructure Replacement	Infrastructure Betterments to commence in 2012 are as follows: - Replace suspect defective porcelain switches.

ID	Total	Description	Category	Project Overview
		Betterments		- Replacement of porcelain dead end bells within distribution system. - Secondary buss replacement. - Replace rotting cross arms. - Replace defective in-line 44kV switches.
DO-007	$33,186	Recloser Automation & Replacements DS-*Reduced scope*	Reliability	Four (4) sets of G&W electronically controlled reclosers are to replace the Big Bay Point D.S. and Sandy cove D.S. hydraulic reclosers. These low maintenance units utilize vacuum break technologies rather than hydraulic oil versions. This technology dramatically reduces the cost of maintenance over the life of the asset. These units will be providing remote communication via the SCADA network which improves the efficiencies and restoration times during outages. and allows recording of momentary and operational data. The electronic reclosers play a compulsory role in the Self healing, smart grid system of the future. Also as part of the project, costs for refurbishment of reclosers due in the 4 year cycle rotation.
DO-008	$ 0	Stroud DS Oil Re-Inhibit Treatment-*Differed*	Substation	Annual testing of transformer oil at Innisfil DS indicates oil quality properties and dissolved gasses are within acceptable limits, however, the oxidation inhibitor is depleted. The oil re-inhibit treatment will deter oil oxidation, thereby, extending the serviceable life of the mineral oil and the reliable life of the transformer.
DO-009	$157,808	27.6kV Mechanized Scada Controlled Load Interpt	Reliability	Install 27.6 kV vacuum line recloser/switch, connect it with SCADA and implement distribution system automation. Total 3 sets to be installed at strategic locations. These switches will be SCADA operated and distribution automation equipped. This is a step forward towards Smart Grid. When commissioned into the future smart grid, they will provide automatic isolation of faulty line sections and automatic power restoration to unaffected sections. They will also provide enhanced reliability and safety.
DO-010	$144,906	44kV Mechanized Scada Controlled Load Interpt	Reliability	Two (2) switches in total. Each of these switches shall replace an aging and obsolete current airbreak or MSO location. Each will provide remote switching capability and real time data acquisition to better manage outage reporting numbers to the OEB. Crew time will be reduced during emergency and non-emergency operations and built in functionality can be used for future smart grid, self-healing considerations within the 44kV subtransmission system.
DO-012	$67,.600	U/G Padmounted TX Replacement	Infrastructure Repalcement	Staff have noticed certain padmount transformers are starting to rust beyond the point of normal repair and painting. To ensure deteriorating padmount

ID	Total	Description	Category	Project Overview
		& Painting		transformers do not pose a safety or environmental risk, a program to identify and replace these transformers shall be established and required year over year to mitigate corrosion from road salt, weather elements and manufacture defect.
DO-013	$172,110	Substandard Transformer Rehabs	Infrastructure Replacement	To address the aging and sub-standard transformer installations where the transformer is installed below the secondary buss. This method of framing was common practice in earlier years of construction to conserve on pole height. These installations now pose a clearance, and subsequent safety risk to staff and the public, while working on or in the vicinity of these installations.
DO-014	$ 0	3 ph 44kV Repooling-Reconductoring 20th 6th to 7th line- *Re-allocated to 2014*	Infrastructure Replacement	A pole and conductor replacement is necessary on 20th SR, from 6th line to 7th line. This is the final piece to create a 27.6kV tie between the Brian Wilson D.S. and new 27.6kV Lefroy D.S. An upgrade of the existing 44kV circuit from 336 MCM to 556 MCM conductor will also occur to maximize the feeder capability of 600 amps. Without this section of line the new Lefroy Station will be islanded without redundancy in an emergency or for maintenance.
DO-015	$191,876	County Relocates IBR & 20th SR	Customer Demand	County is rebuilding and widening the 20th SR and IBR intersection to tie in with the finished Precinct 1 Urbanization. Relocation of Innisfil Hydro infrastructure in this area will have to be done. As reviewed from the County of Simcoe engineering plan, an approximate 6 spans of 44kV double circuit subtransmission and 27.6kV distribution wire and apparatus are in this scope of work.
DO-016	$197,173	County Relocates 7th Ln & 20th SR	Customer Demand	The County Of Simcoe has advised they will be commencing intersection construction @ two (2) locations in 2011. One of which is 20th S.R. @ the 7th Line of Innisfil. Innisfil Hydro must move approximately thirty (30) spans of44kV subtransmission and 27.6 kV circuits at this intersection to meet the County requirements.
DO-017	$379,402	County Relocates IBR & 10th SR	Customer Demand	County is rebuilding and widening Innisfil Beach Rd. and 10th SR intersection. Relocation of Innisfil Hydro infrastructure in this area will have to be done. As reviewed from the County of Simcoe engineering plan, an approximate 12 poles of double circuit 44kV subtransmission and an approximate 15-27.6kV distribution poles are in the scope of this job.
DO-018	$24,000	Urbanization Carry Forward	Customer Demand	With the remainder of the Innisfil Beach Road Urbanization coming to a close, remaining costs incurred for all precincts in the relocate issued by the Town of Innisfil will be assigned here.

ID	Total	Description	Category	Project Overview
DO-019	$154,850	Urbanization 1 Pole Relocate Finish	Customer Demand	As Precinct one (1) still exists in a partially finished state due to property acquisition, County of Simcoe and Metro Links (GO train) involvement, Innisfil Hydro has been advised the County of Simcoe will go ahead with finalization of the IBR and 20th Sideroad. This project scope will finish the remaining portion of Precinct 1.
DO-020	$ 0	Urbanization 2A Lighting Carry Over	Customer Demand	Direct pass through to the Town of Innisfil for the works pertaining to the street lighting installation in Precinct 2A as in the CCDC contract between Innisfil Hydro and R.B. Somerville.
DO-021	$20,020	Cookstown Water Main Relocates	Customer Demand	Direction given to Innisfil Hydro that the Town of Innisfil is undertaking a road widening in the Cookstown area. Project scope will be to relocate conflicted poles as identified from Town of Innisfil Drawings.
DO-022	$465,000	TS Land	Customer Demand	This capital request consists of the Land purchase of a site directly under the 13M3 towerline, that in future will be the location of a new 230kV Transformer Station to feed the intense growth in the south end of Barrie.
DB-001	$74,000	Retail Meters/ Smart Meters	Customer Demand	Maintain adequate supply of retail single and three phase meters.
	$583,370	Base	Customer Demand	Within the daily operations of Innisfil Hydro it is necessary to install, replace, relocate capital infrastructure that is not part of identified capital projects through the year. Examples such as vehicular accidents, storm damage replacement and issues identified by Hydro staff in the day to day operations go to this section of the capital budget. All overhead and underground servicing for customer request like new installs, upgrades, relocates and replacements impact the base budget and also receive contributions towards such works as outlined in the DSC.
TOTAL:	**$3,232,805**			

2012 General Plant

ID	Total	Description	Category	Project Overview
GB-002	$25,000	Replace & Improve Building & Fixtures	Facility	Maintain healthy and efficient work environment.
GO-010	$2,000,000	New Building	Facility	The Initial investment to begin the construction of the new Innisfil Hydro Head Office and Operations Center is slated to start construction in the fall of 2012. The new building investment is to enhance Innisfil Hydro's effectiveness and operations with all departments under one roof rather than the five (5) buildings currently being utilized. G rowth requirements and structural deficiencies have prompted this required expansion.
GB-003	$25,500	Furniture & Equipment	Facility	Replace existing workstations with more ergonomically correct designs and add workstations for new staff.
GB-001	$120,000	Hardware General	Hardware & Software	Maintain and enhance network integrity and security.
GB-001	$73,000	Software General	Hardware & Software	Maintain and enhance network integrity and security.
GF-001	$2,500	Hardware Finance Scanner	Hardware & Software	Upgrade scanner for digitalizing documents to be filed in File nexus.
GF-002	$45,000	GP Upgrade	Hardware & Software	Upgrade for software to obtain support from Microsoft. Additional license for new users.
GO-012	$164,150	Engineering Topobase & IFRS Enhance	Hardware & Software	Internalize asset management. Implement design system and integrate with Topobase IFRS enhancements.
	$93,156	Smart Meter Trueup	Hardware & Software	Smart Meter deployment and disposal.
GO-008	$4,000	Stores Equipment	Tools	Miscellaneous solutions will include better use of limited space for inventory control and it will assist the stock-keeper in faster service for the line crews.
GO-007	$27,000	Fleet Tools	Tools	Purchase of Line tools to support Line personnel and Vehicles
GO-009	$8,500	Measurement & Testing Tools	Tools	To purchase measuring and testing equipment; to be used for distribution line survey (distance and height measuring equipment - electronic and mechanical), Pole GPS and other miscellaneous equipment as needed and justified.

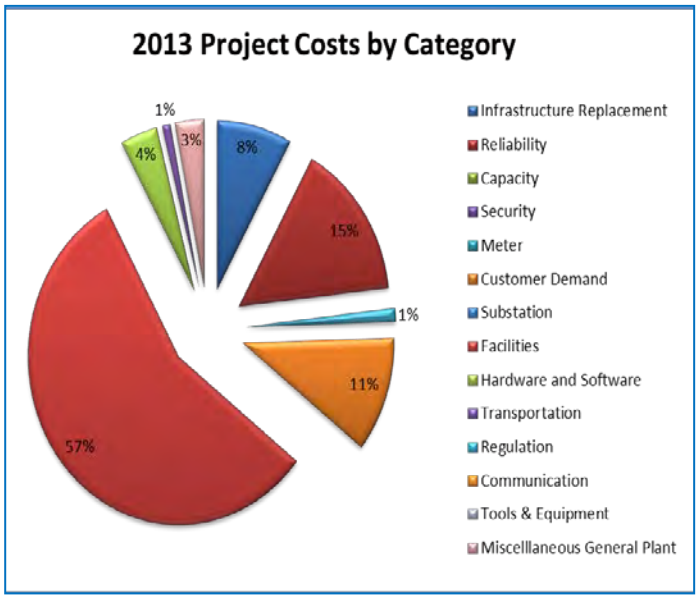
ID	Total	Description	Category	Project Overview
GO-004	$36,300	System Supervisory	Communication	Implementation of new fault indicating and switching devices in the distribution system. Solution for communications from repeater locations to Innisfil Hydro office and some lead acid battery replacement to gelled batteries as required.
GO-005	$35,600	Radio Repeated Faulted Indicators	Communication	Fault indicators indicate and convey status of distribution line via SCADA system. These radio repeated fault indicators will be installed at strategic locations. Communications through SCADA system will provide information about line-section having fault. This will reduce considerable time for line crew locating fault. Provide enhanced outage management system.
GO-006	$ 0	Capacitor Intelilink Automation-*Re-allocated to 2013*	Communication	Innisfil Hydro has installed number of capacitor banks for voltage/ VAR improvements. With the implementation of new SCADA system and using GIS system capabilities; these capacitor banks can be controlled via SCADA. Better voltage management and VAR control will enhance power quality.
GO-011	$200,100	Scada Program Conversion	Communication	Existing SCADA system is obsolete and does not have enough capacity to include more SCADA points. New SCADA system will be a step forward to Smart Grid implementation and can accommodate enhanced capacity server, work stations and can handle more number of points. New SCADA implementation will enhance reliability, faster response time and has the capability to talk with other SCADA systems as well.
	$11,000	Base		Within the daily operations of Innisfil Hydro it is necessary to install, replace, relocate capital infrastructure that is not part of identified capital projects through the year. Examples such as vehicular accidents, storm damage replacement and issues identified by Hydro staff in the day to day operations go to this section of the capital budget. All overhead and underground servicing for customer request like new installs, upgrades, relocates and replacements impact the base budget and also receive contributions towards such works as outlined in the DSC.
TOTAL	**2,955,656**			

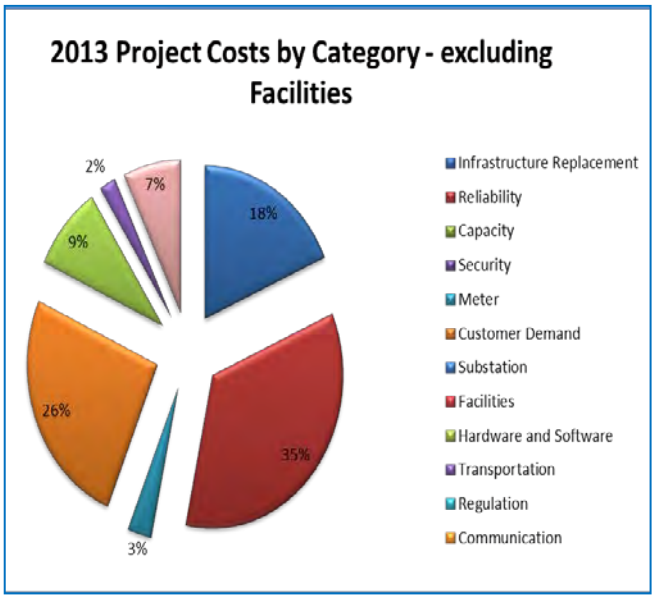
2013 Capital Projects

Projects	Category	2013
2013 Distribution Plant		
DO-001- Station reclosurer	Reliability	207,300
DO-002- 44kV Alduti Ruptor	Reliability	144,500
DO-003-27.6 kV mechanized SCADA controlled Load Interp	Reliability	181,180
DO-004-Infrastructure Repalcements	Customer Demand	210,900
DO-005-UG padmounted TX replacements	Infrastructure Replacement	79,700
DO-006-Substandard transfirmer rehabs	Infrastructure Replacement	182,700
DO-007-Pole replacement	Infrastructure Replacement	391,288
DO-008-29kV extension 20th SDRD BBPT to 13th Line	Reliability	724,294
DO-009-Big Bay Point F3 for BBPT Development	Customer Demand	110,743
DO-010-Utility Relocates	Customer Demand	68,074
DB-001-Retail Meters	Meters	115,900
Base	Customer Demand	615,376
Sub-Total		3,031,955
2013 General Plant		
GB-001 Network Infrastructure for New building	Facility	87,500
GO-010 New building	Facility	5,000,000
GB-003 Hardware	Hardware & Software	185,000
GO-010Eng topobase & IFRS enhancement	Hardware & Software	171,000
GO-003 2 Fleet trucks	Transport	80,000
GO-007 System Supervisory	Reliability	62,000
GO-008 Capacitor intelilink to SCADA	Reliability	51,400
DO - 003 27.6kv mechanized SCADA load interpt	Infrastructure Replacement	72,000
Miscellaneous		279,997
Sub-Total		5,988,897
2012 Grand Total		**9,020,852**

2013 Project Costs by Category

Category	Cost
Infrastructure Replacement	725,688
Reliability	1,370,674
Security	0
Substation	0
Meter	115,900
Customer Demand	1,005,093
Facility	5,087,500
Transport	80,000
Hardware & Software	356,000
Miscelllaneous	279,997
2009 Grand Total	**9,020,852**





2013 Capital Project Summary

2013 Distribution Plant

ID	Total	Description	Category	Project Overview
DO-001	$223,300	Station Recloser	Reliability	Four (4) sets of G&W electronically controlled reclosers are to replace the Big Bay Point D.S. and Sandy cove D.S. hydraulic reclosers. These low maintenance units utilize vacuum break technologies rather than hydraulic oil versions. This technology dramatically reduces the cost of maintenance over the life of the asset. These units will be providing remote communication via the SCADA network which improves the efficiencies and restoration times during outages. and allows recording of momentary and operational data. The electronic reclosers play a compulsory role in the Self-healing, smart grid system of the future. Also as part of the project, costs for refurbishment of reclosers due in the 4 year cycle rotation.
DO-002	$160,100	44kV Aiduti Ruptor	Reliability	Two (2) switches in total. Each of these switches shall replace an aging and obsolete current airbreak or MSO location. Each will provide remote switching capability and real time data acquisition to better manage outage reporting numbers to the OEB. Crew time will be reduced during emergency and non-emergency operations and built in functionality can be used for future smart grid, self-healing considerations within the 44kV subtransmission system.
DO-003	$253,800	27.6kV Mechanized Scada Controlled Load Interpt	Reliability	Install 27.6 kV vacuum line recloser/switch, connect it with SCADA and implement distribution system automation. Total 3 sets to be installed at strategic locations. These switches will be SCADA operated and distribution automation equipped. This is a step forward towards Smart Grid. When commissioned into the future smart grid, they will provide automatic isolation of faulty line sections and automatic power restoration to unaffected sections. They will also provide enhanced reliability and safety.
DO-004	$210,900	Infrastructure Replacements & Bettements	Customer Demand	Infrastructure Betterments to commence in 2013 are as follows: Replace suspect porcelain dead end bells within distribution system. Secondary buss replacement. Replace rotting cross arms. Replace defective in-line 44kV, 27.6 kV and 8.32 kV switches.
DO-005	$79,700	U/G Padmounted TX Replacements & Painting	Infrastructure Replacement	Staff have noticed certain padmount transformers are starting to rust beyond the point of normal repair and painting. To ensure deteriorating padmount transformers do not pose a safety or environmental risk, a program to identify and

ID	Total	Description	Category	Project Overview
				replace these transformers shall be established and required year over year to mitigate corrosion from road salt, weather elements and manufacture defect.
DO-006	$182,700	Substandard Transformer Rehabs	Infrastructure Replacement	To address the aging and sub-standard transformer installations that do conform to ESA Standards where the transformer is installed below the secondary buss. This method of framing was common practice in earlier years of construction to conserve on pole height. These installations now pose a clearance, and subsequent safety risk to staff and the public, while working on or in the vicinity of these installations.
DO-007	$391,288	Pole Replacements	Infrastructure Repalcement	Approximately 1/8th of Innisfil Hydro's poles will be tested through its testing program, with an anticipated 4% failure rate, an estimated 70 po les will be replaced. Twenty (20) poles with live three (3) phase - no transformer. Twenty (20) poles with live one (1) phase - no transformer. Fifteen (15) poles with live three (3) phase with transformer. Fifteen (15) poles with live one (1) phase with transformer.
DO-008	$724,294	27kV Extension 20th SR, BBPt to 13th Line	Reliability	Installation of a circuit of 27.6 kV (336 kcmil conductor) on 20th SR from 10th line to 13th line and E on 13th line from 20th SR to Fairway Rd. Previous projects have set the foundation for this project to link the Brian Wilson D.S. to a future 27.6 kV Station in Big Bay Point. Also in this scope will be the Installation of a 44 k V circuit (556 kcmil conductor) and 27.6 kV circuit (336 kcmil conductor) on 13th line, from Fairway Rd. to the intersection of 25th Sideroad just west of the south Entrance of the proposed BBPT development (Friday Harbour resort). Without this line, the future BBPT Station will be islanded without redundancy in an emergency or for maintenance.
DO-009	$110,743	Big Bay Pt F3 for BBPt Development	Customer Demand	To prepare for the first phase of the Big Bay Point Development, we need to rebuild existing three (3) phase 8.3kV line east of Big Bay Point DS along the 13th Line to the south entrance of the development to accommodate new three (3) phase 27.6kV circuit feeding Big Bay Point Development.
DO-010	$68,074	Utility Relocates	Customer Demand	Year over year Innisfil Hydro is engaged by external forces ie. County of Simcoe, MTO, Town of Innisfil to relocate sections of overhead or underground plant within their right of way. Commonly Innisfil hydro is approached within its current capital budget year with no advanced notice the previous year to budget a project scope. This Capital Asset Request is for such relocate requests that need to occur within the same capital budget year.

ID	Total	Description	Category	Project Overview
DB-001	$115,900	Retail Meters	Meter	Maintain adequate supply of retail single and three phase meters.
	$615,376	Base	Customer Demand	Within the daily operations of Innisfil Hydro it is necessary to install, replace, relocate capital infrastructure that is not part of identified capital projects through the year. Examples such as vehicular accidents, storm damage replacement and issues identified by Hydro staff in the day to day operations go to this section of the capital budget. All overhead and underground servicing for customer request like new installs, upgrades, relocates and replacements impact the base budget and also receive contributions towards such works as outlined in the DSC.
TOTAL:	**$3,031,955**			

2013 General Plant

ID	Total	Description	Category	Project Overview
GB-001	$87,500	Network Infrastructure in New Building	Facility	Move virtualized network and Nortel BCM to new location assumes all cabling is included in building construction, assumes dedicated fire suppression and generation backup are included in building construction, assumes dedicated air/conditioning included in building construction.
GB-002	$5,000	Security for New Building	Facility	Physical and electronic security. Surge protected electrical panel. Full building on auto failover to NG generation monitoring with cell phone dVac lines for 24x7 with cell phone for b/u Fire-alarm system.
GB-005	$35,000	Replace and Improve Bldg & Fixtures	Facility	Maintain healthy and efficient work environment.
GO-010	$5,000,000	New Building	Facility	The remaining investment to construct a facility that started in 2012. The new building will enhance Innisfil Hydro's effectiveness and operations in 2013 with all departments under one roof rather than the five (5) buildings currently being utilized. G rowth requirements and structural deficiencies have prompted this required expansion.
GB-004	$35,000	Furniture & Equipment	Facility	Replace existing workstations with more ergonomically correct designs and add workstations for new staff.

ID	Total	Description	Category	Project Overview
GB-003	$125,000	Hardware General	Hardware & Software	Maintain and enhance network integrity and security.
GB-003	$60,000	Software General	Hardware & Software	Maintain and enhance network integrity and security.
GF-001	$47,500	GP Upgrade	Hardware & Software	Upgrade for software to obtain support from Microsoft. Additional license for new users.
GO-010	$3,000	Engineering Topobase & IFRS Enhance	Hardware & Software	Integrate GIS with Smart Meters. Enhance design system and integrate with topobase. IFRS enhancements.
GO-002	$30,000	Stand Up Inside Fork Lift	Transport	In the new Innisfil Hydro facility, a small maneuverable forklift will be required in the stores/warehouse area to reach shelving and storage out of reach, maximizing the space within this area. One is currently not owned at the existing Innisfil Hydro location.
GO-003	$80,000	Fleet Trucks 2	Transport	The replacement of a 1993 Double Bucket truck will be required. This truck was purchased second hand from another power company in 2010 and will be at the end of its useful life.
GO-004	$4,200	Stores Equipment	Tools	Miscellaneous solutions will include better use of limited space for inventory control and it will assist the stock-keeper in faster service for the line crews.
GO-005	$20,000	Fleet Tools	Tools	Purchase of Line tools to support Line personnel and Fleet Vehicles.
GB-006	$6,000	Measurement & Testing for Metering	Tools	Measuring and testing equipment for metering (eg CT testing).
GO-006	$13,000	Measurement & Testing Tools	Tools	Locator Replacement and replacement and purchases of electronic devices as needed and justified.
GO-007	$62,000	System Supervisory	Reliability	Implementation of new fault indicating and switching devices in the distribution system. Solution for communications from repeater locations to Innisfil Hydro office. Some lead acid battery replacement to gelled batteries as required and low voltage electronic board and module replacements as required.
GO-008	$51,400	Capacitor Intelilink to Scada	Reliability	Innisfil Hydro has installed a number of capacitor banks for voltage/ VAR improvements. With the implementation of the new SCADA system and using GIS system capabilities; these capacitor banks can be controlled via SCADA. Better voltage management and VAR control will enhance power quality.

ID	Total	Description	Category	Project Overview
GO-009	$38,400	Radio Repeated Fault Indicators	Communication	Fault indicators indicate and convey status of distribution line via SCADA system. These radio repeated fault indicators will be installed at strategic locations and be available for end of life replacement indicators already existing within Innisfil Hydro's service territory. Communications through SCADA system will provide information about line-section having fault. This will reduce considerable time for line crew locating fault. Provide enhanced outage management system.
	$11,297	Base		Within the daily operations of Innisfil Hydro it is necessary to install, replace, relocate capital infrastructure that is not part of identified capital projects through the year. Examples such as vehicular accidents, storm damage replacement and issues identified by Hydro staff in the day to day operations go to this section of the capital budget. All overhead and underground servicing for customer request like new installs, upgrades, relocates and replacements impact the base budget and also receive contributions towards such works as outlined in the DSC.
TOTAL:	**$5,988,897**			

1

ASSET MANAGEMENT PLAN SUMMARY:

IHDSL is an infrastructure-based business with its distribution system assets the key element in the delivery of electricity to its existing and new customers. IHDSL's distribution assets range in age from new to over 60 years old.

Asset management is the professional management of physical infrastructure with a systematic methodology integrating best practices in all aspects of selection, design, construction, operation, maintenance, replacement and disposition. The goal is to use an Asset Management Plan to optimize the whole life business impact of costs, performance and risk exposures of IHDSL physical assets. Performance of the assets is directly related to reliability of the distribution system which is another key regulatory and customer satisfaction measure second only to rates.

Accompanying this Schedule as Appendix A is a copy of our 2011 Asset Management Plan. It is important to note that IHDSL's Asset Management Plan is continually evolving in accordance with our infrastructure requirements.

IHDSL has completed a high level review of current assets and their age and has reviewed current strategies in dealing with maintenance and capital improvements. As a result IHDSL has incorporated both capital and maintenance within the budget process to ensure performance of our distribution system.

CAPITALIZATION POLICY

IHDSL has historically applied the following general capitalization policies and principles based on Canadian Generally Accepted Accounting Principles ("CGAAP"), as well as guidelines set out by the Ontario Energy Board, where applicable. No changes to IHDSL's capitalization policy were required with the transition to the Modified International Financial Reporting Standards (MIFRS) as overheads were not included in capital costs.

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.

- Assets that are intended to be used on an on-going basis and are expected to provide future economic benefit greater than one year will be capitalized.
- Expenditures that create a physical betterment or improvement of the asset will be capitalized.
- With respect to transportation equipment all costs associated with placing a vehicle into service are capitalized.

GUIDELINES FOR CAPITALIZATION

Capital Assets

Capital Assets include tangible assets which include property, plant, and equipment provided they are held for use in the production or supply of goods and services. A capital expenditure must provide a benefit lasting beyond one year. C apital expenditures also include the improvement or "betterment" of existing assets. Intangible assets are also considered capital assets and are identified as assets that lack physical substance.

Betterment

A "betterment" is a cost which enhances the service potential of a capital asset and is therefore capitalized. A "betterment" includes expenditures which increase the capacity of the asset, lower

associated operating costs of the asset, improve the quality of output or extend the asset's useful life.

Repair

A repair is a cost incurred to maintain the service potential of a capital asset. Expenditures for repairs are expensed to the current operating period. Expenditures for repairs and/or maintenance designed to maintain an asset in its original state are not capital expenditures and should be charged to an operating account.

CAPITAL ASSET COST

Cost

Cost is the amount of consideration given up to acquire, construct, develop or better a capital asset. Capital assets will be recorded at the fully allocated cost.

Fully Allocated costs

Fully allocated costs include all expenditures necessary to put a capital asset in service including all overhead cost based on full absorption costing.

Amortization

Capital assets are amortized based on a method and life set by the OEB which is considered a suitable indicator of estimated useful life for the electrical distribution industry.

Capital Spares

Spare transformers and meters will be accounted for as capital assets since they form an integral part of the reliability program for a distribution system. These spares are held for the purpose of backing up transformers and meters in-service for a distribution system.

IHDSL SERVICE QUALITY & RELIABILITY PERFORMANCE

IHDSL tracks service reliability statistics SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index) including and excluding loss of supply related incidents. However, reliability statistics excluding loss of supply have only been recorded since 2010. The following shows results for the past three years.

Table 3.8 - Service Reliability Statistics

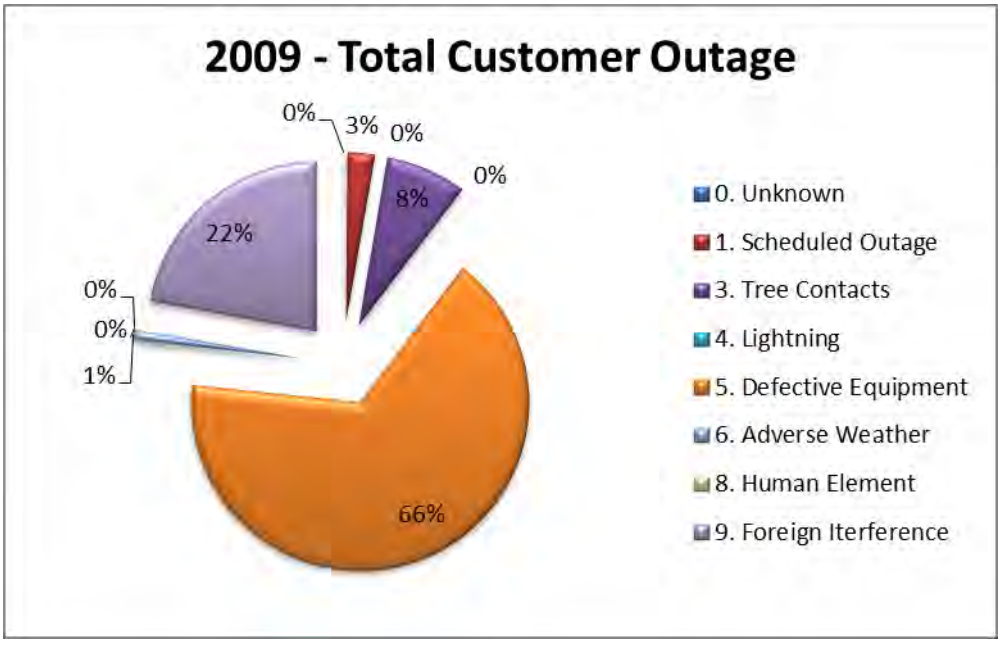
Table 3.8 - Service Reliability Statistics			
Year	**SAIDI**	**SAIFI**	**CAIDI**
Including Loss of Supply			
2008	5.79	4.42	1.31
2009	1.37	1.36	0.99
2010	1.39	1.53	0.91
2011	1.04	1.39	0.75
Excluding Loss of Supply			
2008	1.34	1.03	1.30
2009	1.34	1.37	0.97
2010	1.33	1.19	1.13
2011	0.98	1.11	0.88

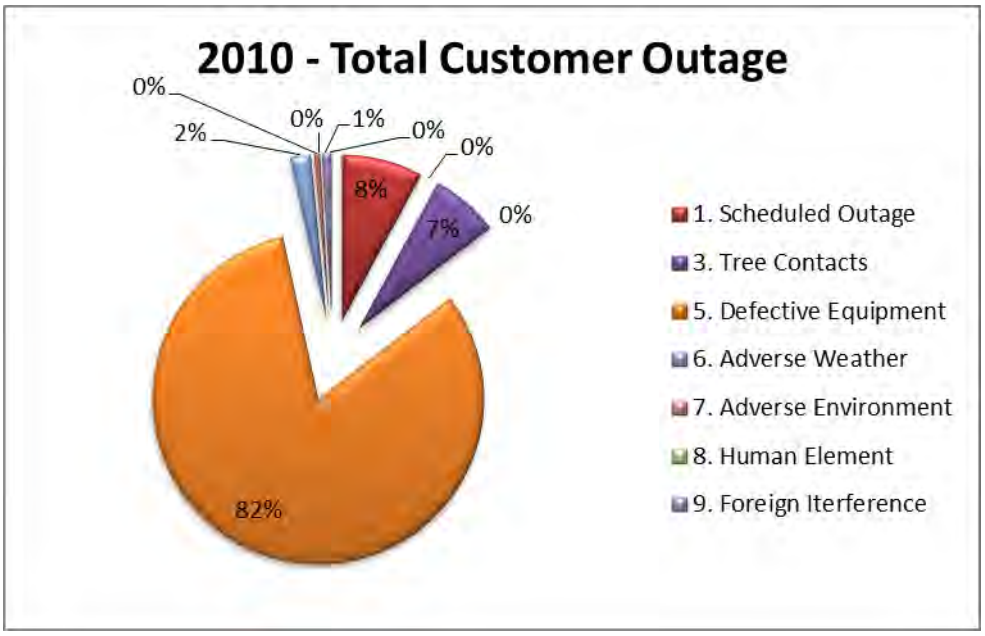
IHDSL is committed to the reliability of the distribution system and has set 2012 target indices for SAIDI and SAIFI as follows:

Table 3.9 – Target Indices for 2012		
	Including Loss of Supply	**Excluding Loss of Supply**
SAIDI	1.39	1.34
SAIFI	1.53	1.37

In order to meet these targets IHDSL will need to continue to invest in capital and maintenance programs. In particular, the capital programs previously noted in Exhibit 2 with a primary driver of asset renewal are aimed at rebuilding infrastructure with a high probability of failure. Renewal of these assets removes the risk to reliability and safety that would otherwise be unacceptable.

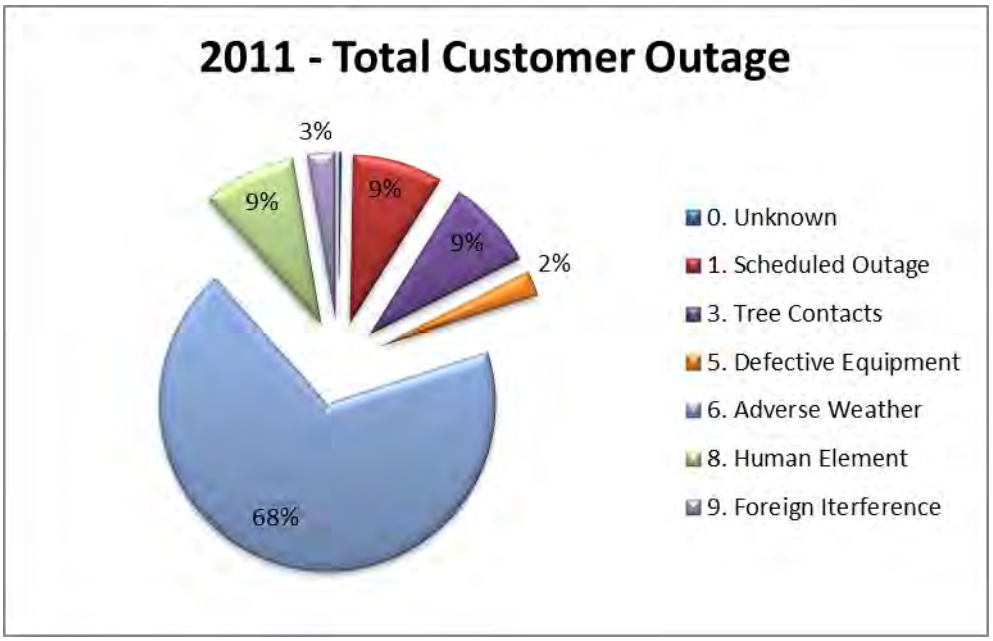
IHDSL is of the view that the capital spend has been prudent and is demonstrated by our Service Reliability Indices which have been improved well within the previous 3 year range as required. Implementation of preventative maintenance and replacement infrastructure programs have certainly changed the outage outcomes from defective equipment failures to outages caused by storms.




2010 - Total Customer Outage
0%
2%
0%
1%
0%
0%
8%
7%
0%
82%
1. Scheduled Outage
3. Tree Contacts
5. Defective Equipment
6. Adverse Weather
7. Adverse Environment
8. Human Element
9. Foreign Iterference

1

2


2011 - Total Customer Outage
3%
9%
9%
9%
2%
68%
0. Unknown
1. Scheduled Outage
3. Tree Contacts
5. Defective Equipment
6. Adverse Weather
8. Human Element
9. Foreign Iterference

3

4

In addition to the reliability indices, IHDSL also measures service quality indicators ("SQIs"). The table below summarizes IHDSL's reported SQIs for the historical years 2008 and 2009. In 2010, the SQI's were replaced by the Electricity Service Quality Requirements (ESQRs).

Table 3.10 - Reported Service Quality Indicators (SQIs)

Indicator	OEB Minimum Standard	2008	2009	2010	2011
Connection of New Services – Low Voltage	90% within 5 days	95%	94%	97%	81%
Connection of New Services – High Voltage	90% within 10 days	n/a	n/a	n/a	n/a
Underground Cable Locates	90% within 5 days			61%	45%
Telephone Call Abandon Rate	65% of calls answered within 30 seconds			89%	96%
Appointments - Scheduled	90% of the time	100%	100%	87%	58%
Appointments - Met	90% of the time	100%	82%	84%	60%
Written Responses to Inquiries	80% within 10 days	100%	100%	100%	100%
Emergency Response – Urban Areas	80% within 60 minutes	n/a	n/a	n/a	n/a
Emergency Response – Rural Areas	80% within 120 minutes	100%	100%	100%	100%

IHDSL SCORECARD

As directed by the RRR Filing Guide issued on April 3, 2012 by the Board, IHDSL tracks, monitors, analyzes and takes appropriate action on a monthly basis for all SQI's.

A copy of our Scorecard is enclosed.

IHDSL Scorecard

Key Performance Indicators (KPI's)

INDEX

Service quality indicators and reporting requirements, including the minimum standard guidelines where applicable, are described in the Scorecard along with IHDSL's results for the first half of the year.

Going forward the Scorecard will be distributed on the 15th of each month, for the previous month.

Performance Indicators	Requirement	Page
Connection of New Services	OEB	2
Underground Cable Locates	Internal	3
Appointments		4 - 5
• Appointment Scheduling	OEB	4
• Appointments Met	OEB	5
Telephone Accessibility		6 - 10
• Answered within 30 Seconds	OEB	6
• Abandoned Calls	OEB	7
• Average Time to Abandon	Internal	8
• Average Time to Answer	Internal	9
• Average Call Length	Internal	10
Written Response to Inquiries	OEB	11
Emergency Response	OEB	12
Emergency Response – Average Time to Respond	Internal	12
Summary of Service Reliability Statistics	OEB	13
System Average Interruption Duration Index	OEB	14
System Average Interruption Frequency Index	OEB	15
Customer Average Interruption Duration Index	OEB	16
Service Interruption by Cause	Internal	17-18
Human Resources – 2012 Attendance Reports	Internal	19-22
CDM Quarterly	Internal	23-24
Financial	Internal	25-26

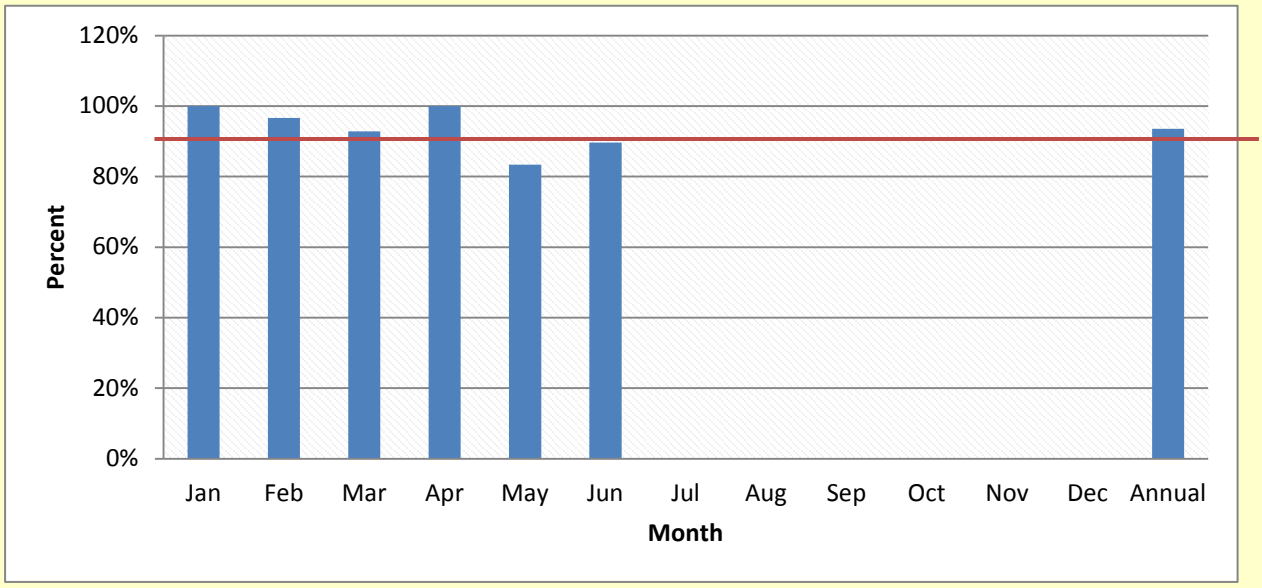
Connection of New Services

OEB Report 2.1.4.1.1

Definition:

As a minimum performance standard for the connection of new universal services, new low voltage (<750 volts) services must be connected within 5 business days from the day on which all conditions of service are satisfied, including electrical safety inspection, at least 90% of the time on an annual basis. The connection of new services indicator measures the percentage of requests that are met within the required minimum.

	2007	2008	2009	2010	2011	2012 YTD
# Connections Within 5 Bus. Days	247	374	234	271	190	102
Total Connection Requests	253	395	248	279	234	109
% Requests Within 5 Bus. Days	98%	95%	94%	97%	81%	94%



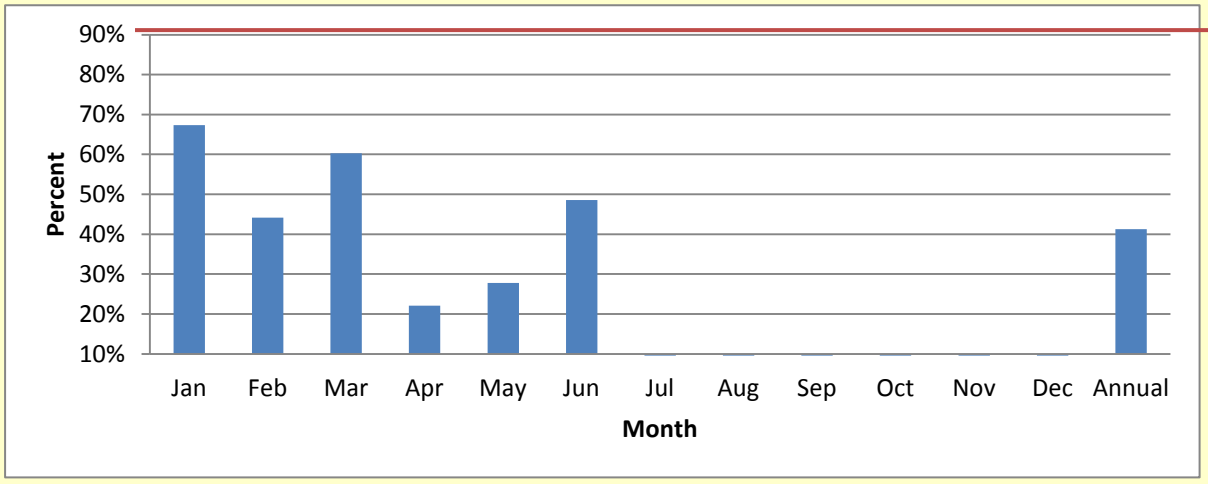
Underground Cable Locates

Major component of the OEB Appointment, Scheduling, Met and Rescheduling. The other major component is Connection of New Services.

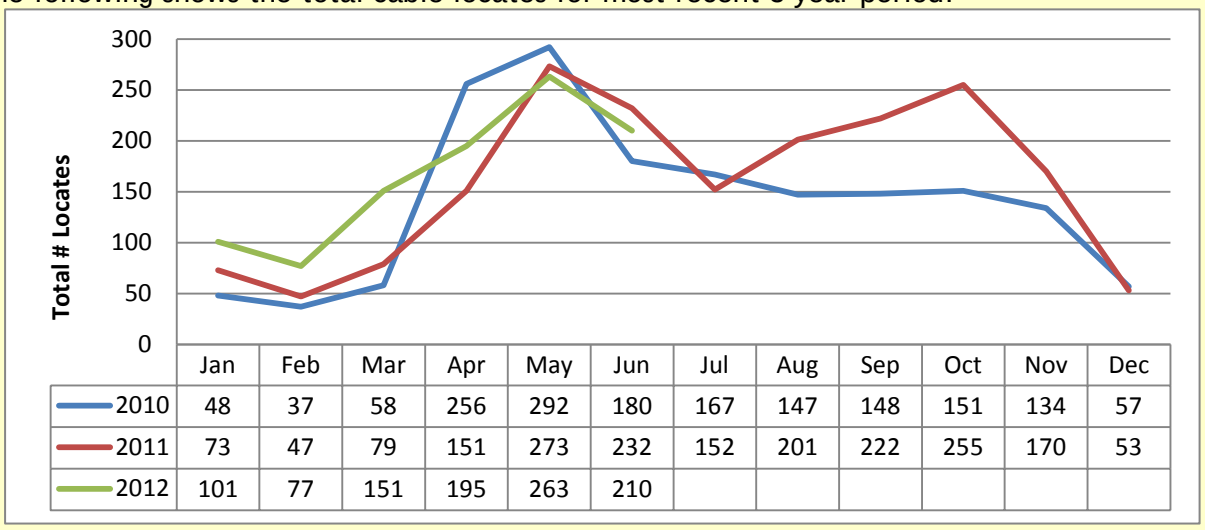
Definition:

The current minimum standard is that underground cable locates must be completed within 5 working days of a customer's request, at least 90% of the time on an annual basis. For customers requesting a specific date, the locate must be completed within 5 working days of the requested date.

2007	2008	2009	2010	2011	2012 YTD
			61%	45%	41%



The following shows the total cable locates for most recent 3 year period:



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010	48	37	58	256	292	180	167	147	148	151	134	57
2011	73	47	79	151	273	232	152	201	222	255	170	53
2012	101	77	151	195	263	210						

Note: After 2007, Underground Cable Locates is included in the Appointments Met metric.

Appointments Scheduled

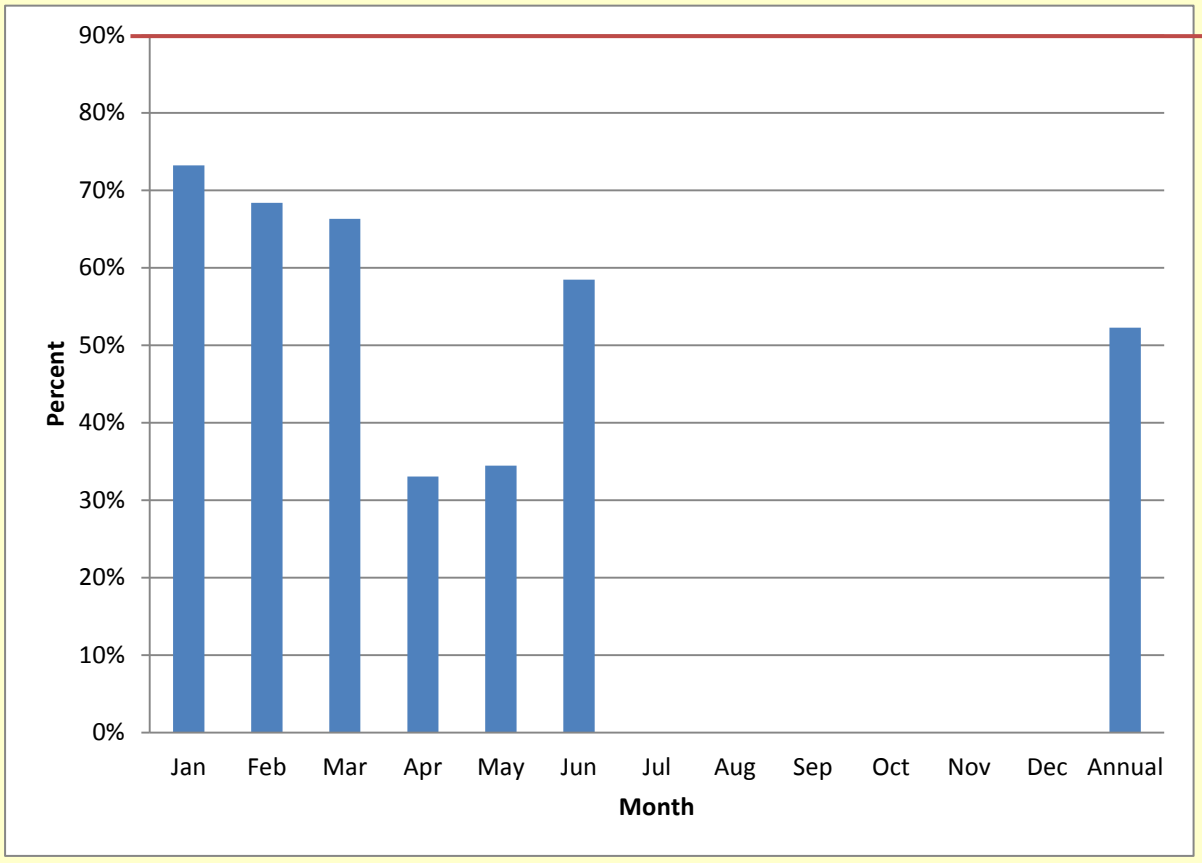
OEB Report 2.1.4.1.2

Definition:

The appointments indicator measures the percentage of appointments at a customer's premises or work site that are scheduled within the 5 business day window. This service quality requirement must be met at least 90% of the time on an annual basis.

Beginning in 2012, Underground Locates and New Connections are included in Appointments Scheduled.

2012	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
# Appointments scheduled/completed	101	106	126	75	104	159							671
# Appointment requests received	138	155	190	227	302	272							1284
% Appointments scheduled/completed	**73%**	**68%**	**66%**	**33%**	**34%**	**58%**							**52%**



Appointments Met

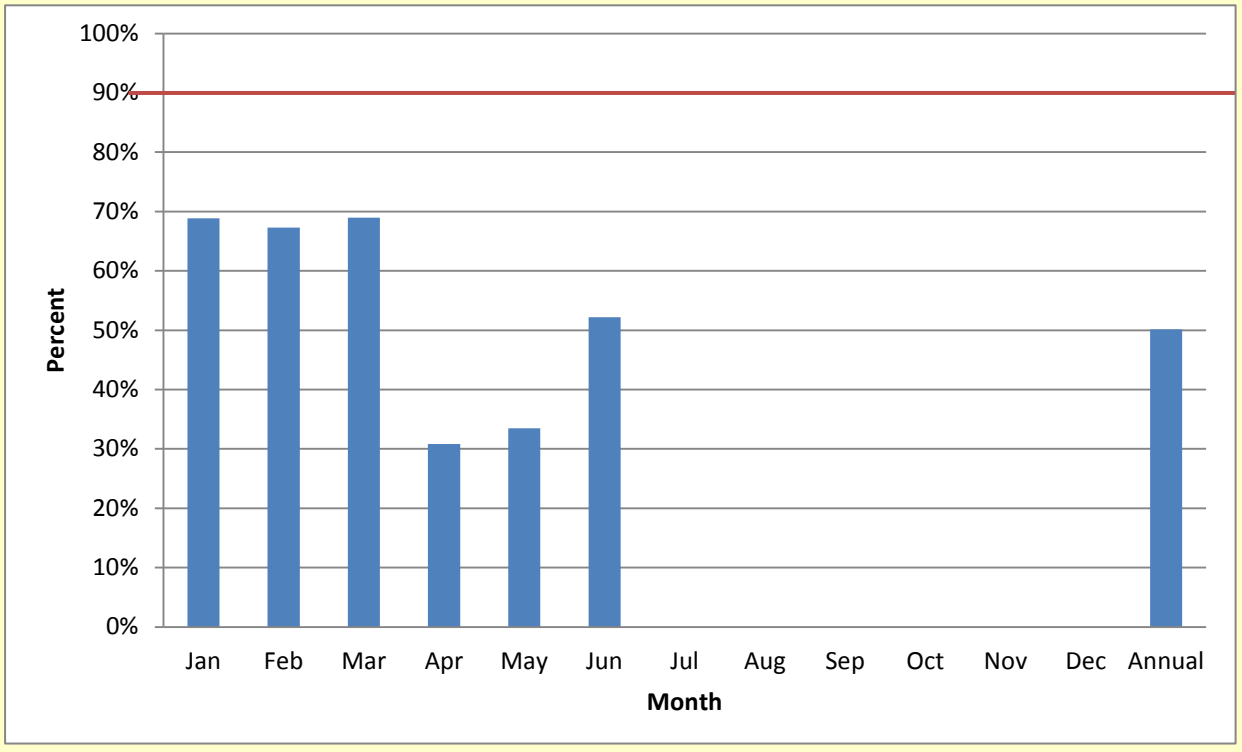
OEB Report 2.1.4.1.3

Definition:

The appointments indicator measures the percentage of appointments at a customer's premises or work site that are met at the appointed time within the minimum performance standard. As a minimum standard, the appointment must be met within a window no greater than 4 hours. The appointments must be met within this window at least 90% of the time on an annual basis; IHDSL must notify the customer if the appointed time cannot be met.

Beginning in 2012, Underground Locates and New Connections are included in Appointments Met.

2012	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
# Appointments completed as scheduled	95	105	131	70	101	142							**502**
# Appointments scheduled	138	156	190	227	302	272							**1013**
% Appointments met	**69%**	**67%**	**69%**	**31%**	**33%**	**52%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	50%



Telephone Accessibility
Calls Answered Within 30 Seconds

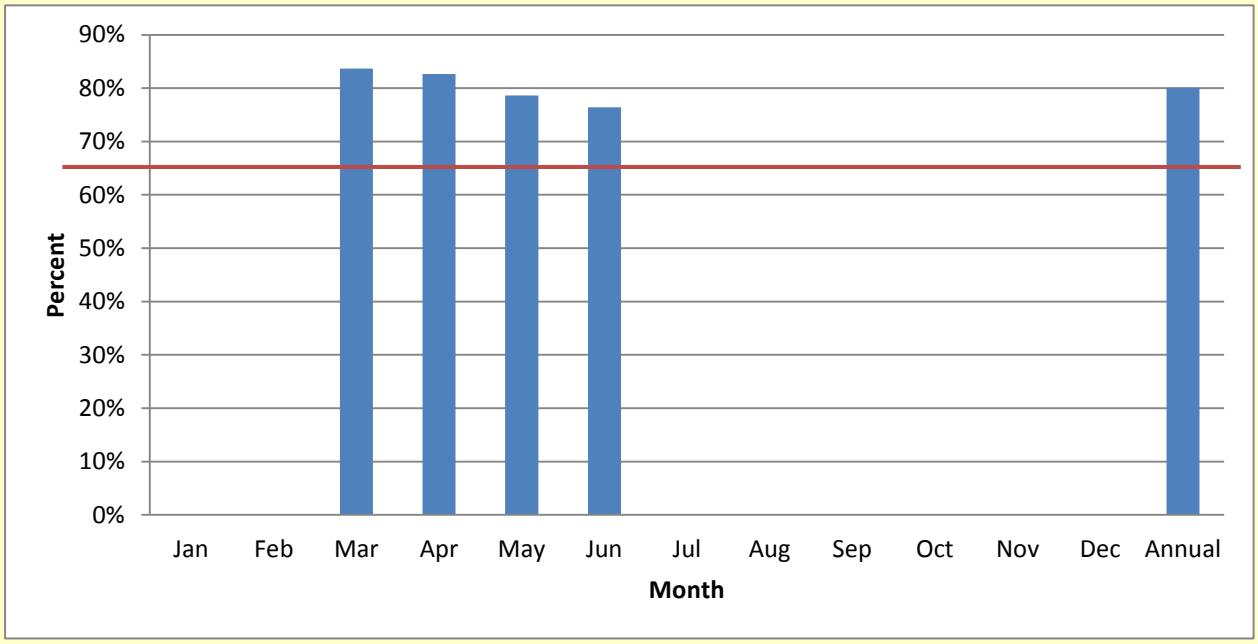
OEB Report 2.1.4.1.5

Definition:

Qualified incoming calls to IHDSL's customer care telephone number must be answered within a 30 second time period. The service quality requirement must be met at least 65% of the time on an annual basis. For qualified incoming calls that are transferred from IHDSL's Nortel phone system, the 30 seconds is counted from the time the customer selects to speak to a customer service representative. In all other cases, the 30 seconds is counted from the first ring.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
# Calls Answered < 30 sec.			998	1355	1319	1274							**4946**
# Incoming Calls			1193	1639	1677	1667							**6176**
			84%	**83%**	**79%**	**76%**							**80%**

Note: Data available from March 9, 2012 due to installation of new system



Telephone Accessibility
Abandoned Calls

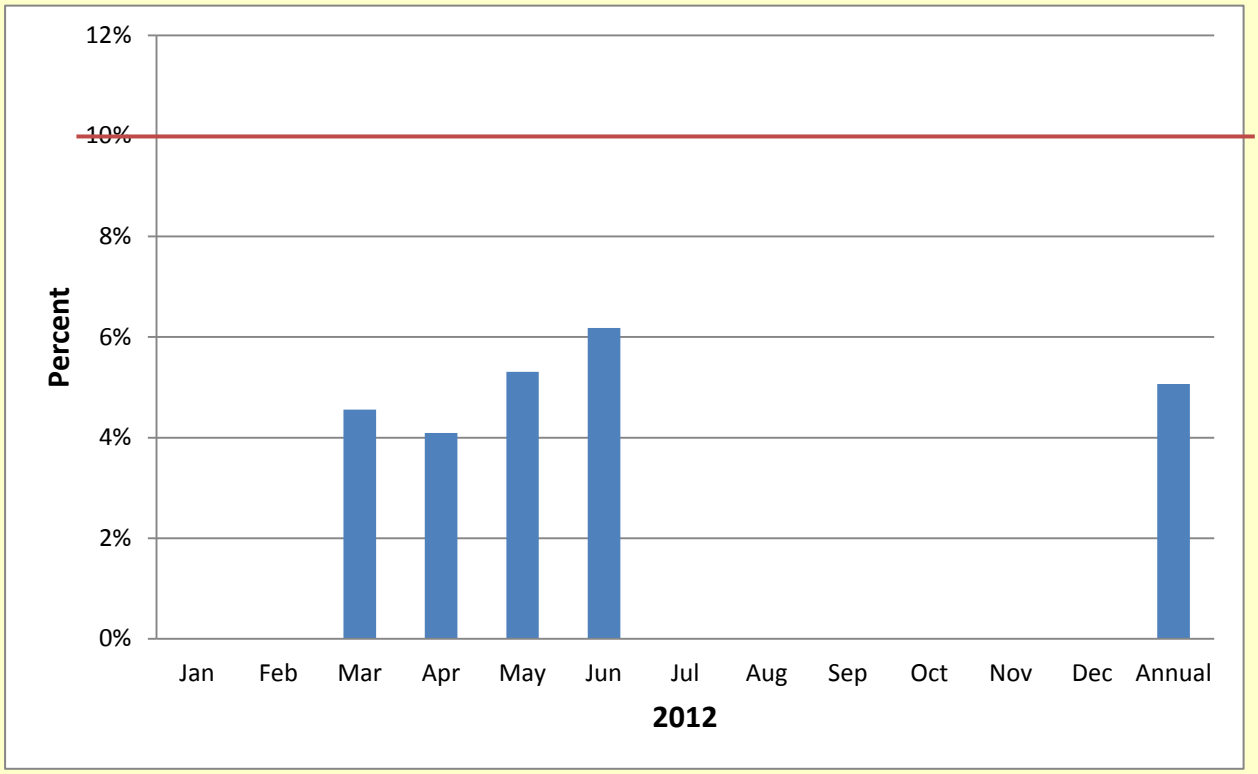
OEB Report 2.1.4.1.6

Definition:

The number of qualified calls to IHDSL's customer care telephone number that are abandoned before they are answered shall be 10 percent or less on an annual basis.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
# Abandoned			57	70	94	103							**324**
# Incoming Calls			1250	1709	1771	1667							**6397**
			5%	**4%**	**5%**	**6%**							**5.1%**

Note: Data available from March 9, 2012 due to installation of new system.



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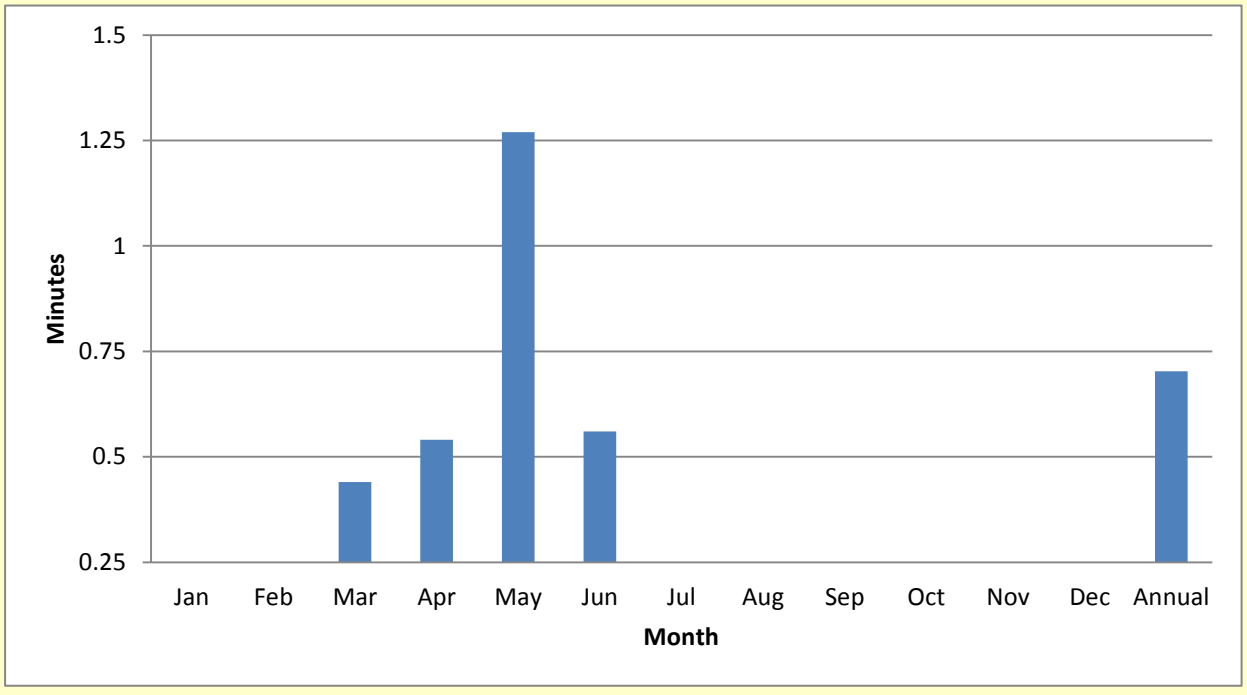
Telephone Accessibility
Average time to Abandon

This is an internal measurement which identifies a customer's tolerance to wait for a Customer Service Representative. The time reflected is tracked once a customer opts for the CSR queue.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
# Incoming Calls			1250	1709	1771	1667							**6397**
Average Time to Abandon (mns)			**0.44**	**0.54**	**1.27**	**0.56**							**0.70**

Note: Data available from March 9, 2012 due to installation of new system

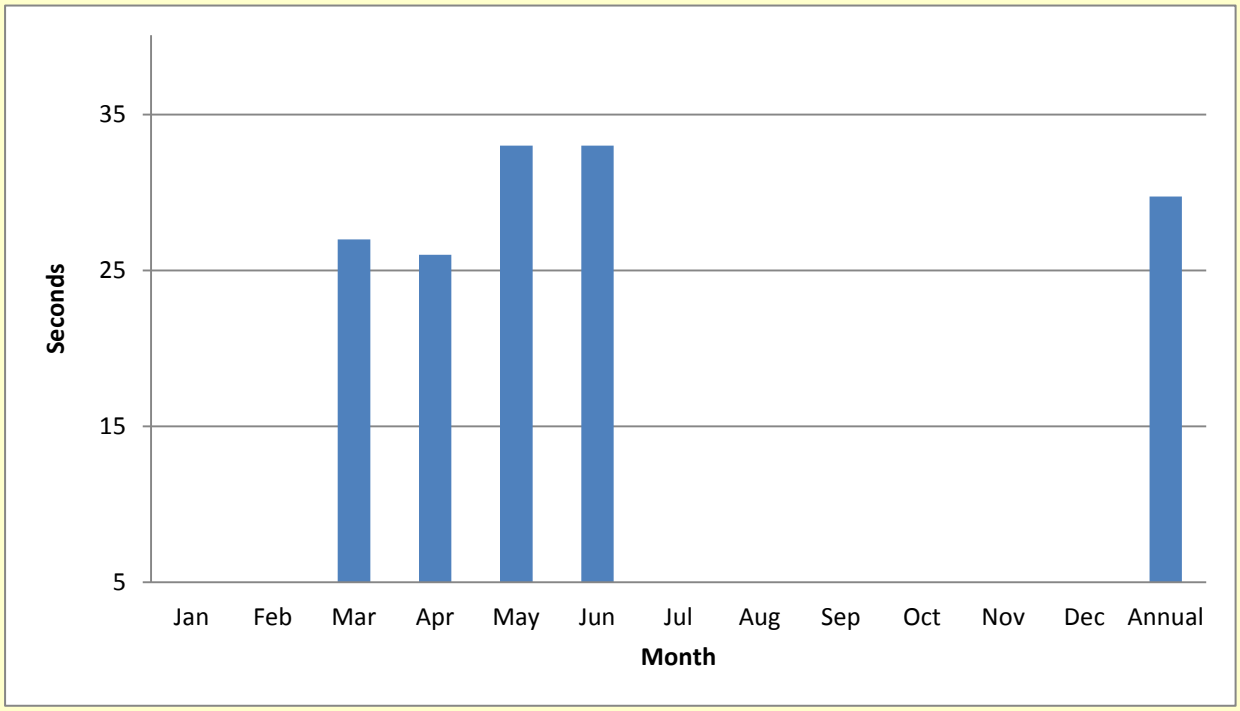


Telephone Accessibility
Average Time to Answer

This is an internal measurement, used to tack the average time taken to answer an incoming customer call.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
# Incoming Calls			1250	1709	1771	1667							**6397**
Average Time to Answer (seconds)			**27**	**26**	**33**	**33**							**29.75**

Note: Data available from March 9, 2012 due to installation of new system



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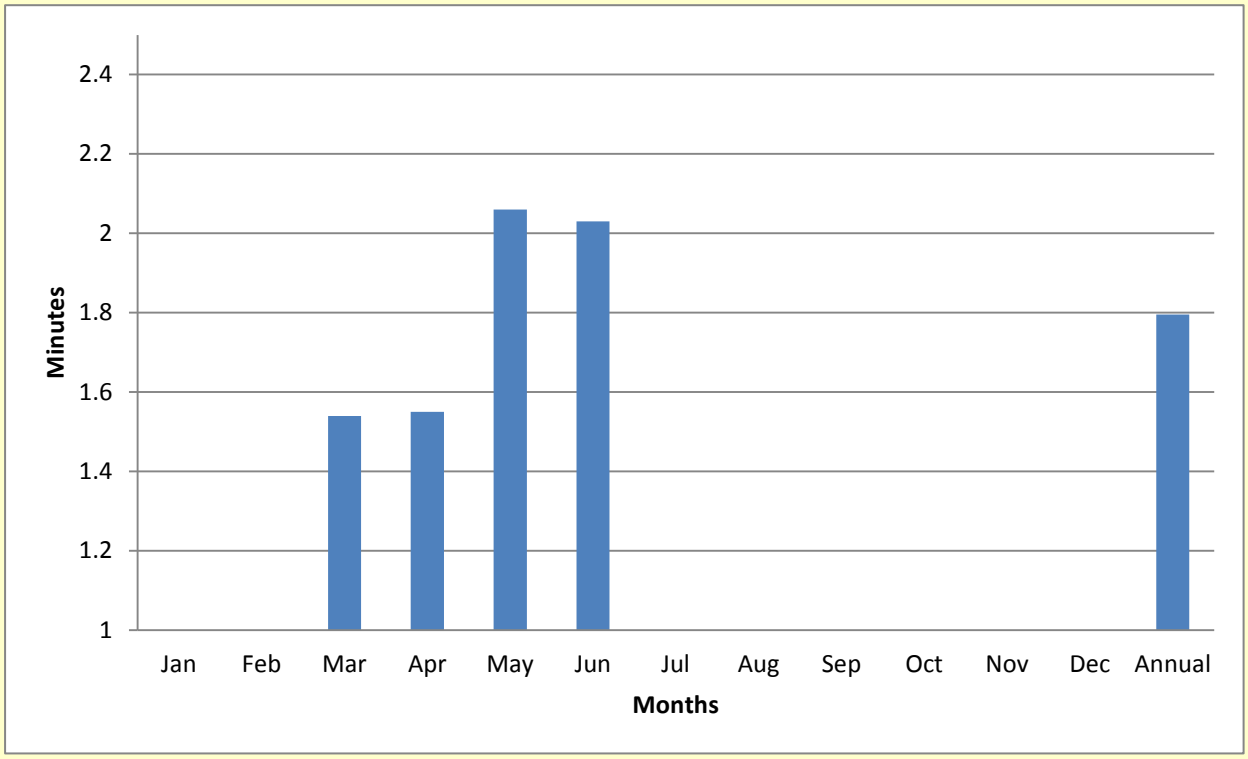
Telephone Accessibility
Average Call Length

This is an internal measurement, used to track the average length of a customer call.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Average Call Length			1.54	1.55	2.06	2.03							1.79

Note: Data available from March 9, 2012 due to installation of new system



Upcoming Potential Call Impacts:

- Wastewater Billing
- October Bills – OCEB Kw Threshold Change

Written Responses to Enquiries

OEB Report 2.1.4.1.7

Definition:

The minimum standard for responding to requests by a customer or an agent of the customer for written information relating to the customer's account will be within 10 working days following receipt of the request. The written response time must be met at least 80% of the time on an annual basis.

Gap: All customer requests must be logged in a central filing system.

Recommendation:

2007	2008	2009	2010	2011	2012 YTD
100%	100%	100%	100%	100%	100%

2012	Jan	Feb	Mar	Apr	May	Jun	Total
# of Written Responses Provided in 10 days	74	51	66	110	140	141	582
# of Qualified Enquiries Received	74	51	66	110	140	141	582
% Written Responses Provided in 10 days	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

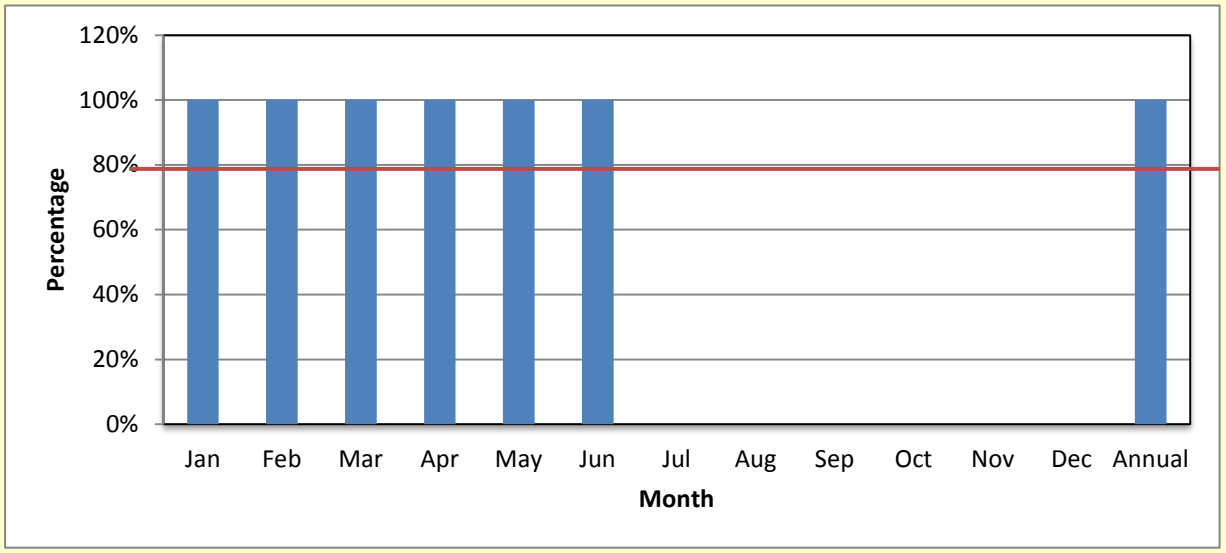
Emergency Response in Rural Areas

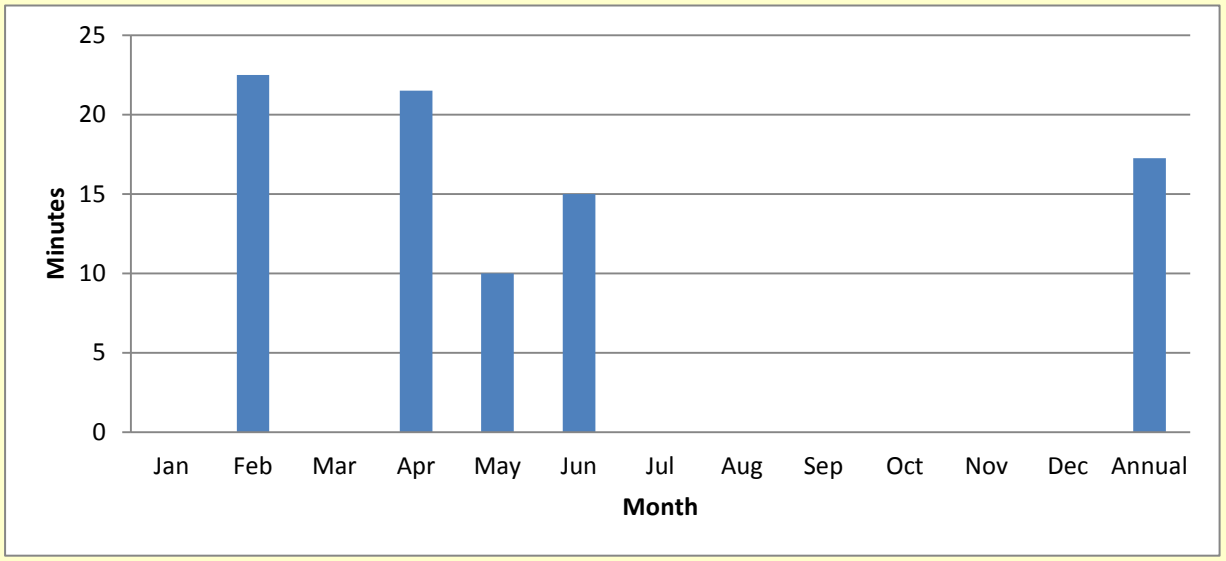
OEB Report 2.1.4.1.8

Definition:

Emergency calls must be responded to within 120 minutes in rural areas, at least 80% of the time on an annual basis.

2007	2008	2009	2010	2011	2012 YTD
100%	100%	100%	100%	100%	100%





SUMMARY OF SERVICE RELIABILITY STATISTICS

IHDSL tracks service reliability statistics SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index).

Reliability Indicator		Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Annual 2012	Annual 2011
System Average Interruption Duration Index (SAIDI)	All outages	0.03	0.77	0.81	0.06	0.00	0.06							1.74	1.04
	Excluding Loss of Supply*	0.03	0.00	0.05	0.06	0.00	0.06								
System Average Interruption Frequency Index (SAIFI)	All outages	0.06	0.22	0.31	0.04	0.00	0.06							0.72	1.39
	Excluding Loss of Supply*	0.06	0.00	0.01	0.04	0.00	0.06								
Customer Average Interruption Duration (CAIDI)	All outages	0.52	3.48	2.38	1.77	2.95	1.07							2.43	0.75
	Excluding Loss of Supply*	0.52	1.52	3.35	1.77	2.95	1.07								

Note: The following graphs are shown excluding "Loss of Supply". For the purposes of this Scorecard, we are addressing those instances where we have control only.

System Average Interruption Duration Index (SAIDI)

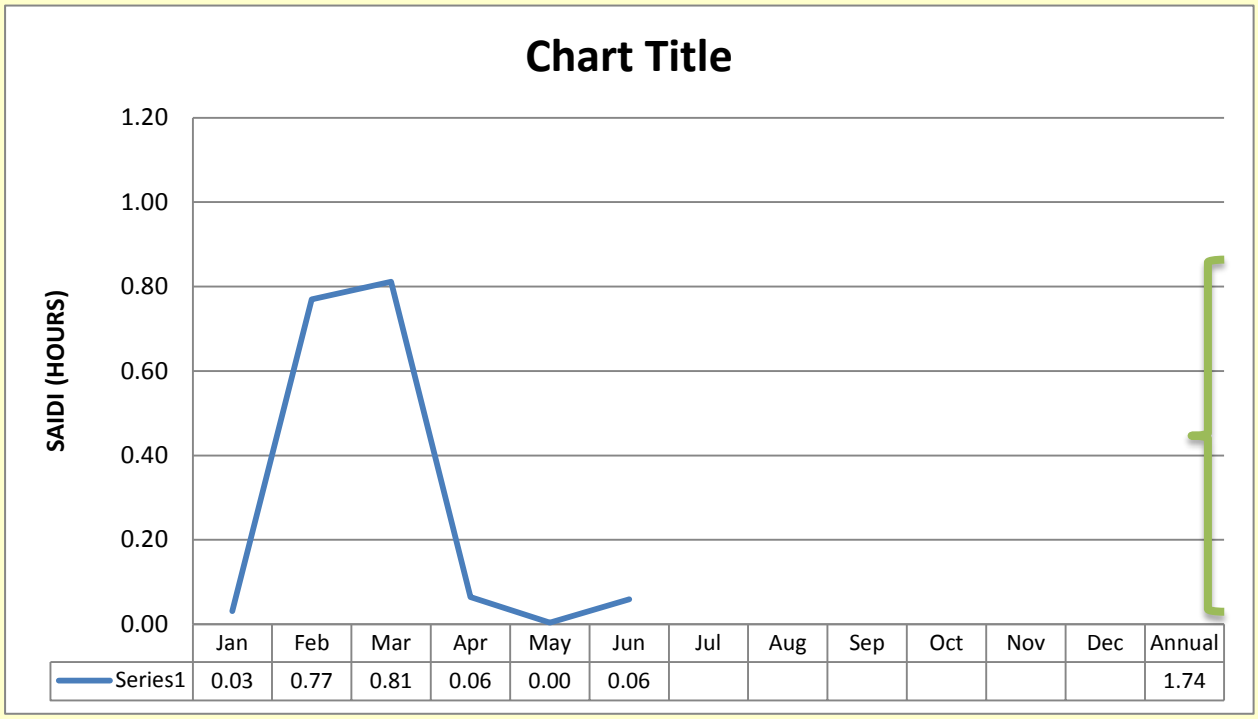
Excluding Loss of Supply

SAIDI is an indicator of system reliability that expresses the length of outage customers experience in the year, on average. All planned and unplanned interruptions of one minute or more are used to calculate this index. It is defined as the total hours of power interruptions normalized per customer served, and is expressed as follows:

$$\text{SAIDI} = \frac{\text{Total Customer Hours of Interruptions}}{\text{Total Number of Customers Served}}$$

IHDSL is required to remain, at minimum, within the range of our historical 3-year performance.

The range for the period 2009 to 2011 is: 0 to .83 hours; therefore, IHDSL has remained within the range for 2012 to-date.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Series1	0.03	0.77	0.81	0.06	0.00	0.06							1.74

System Average Interruption Frequency Index (SAIFI)

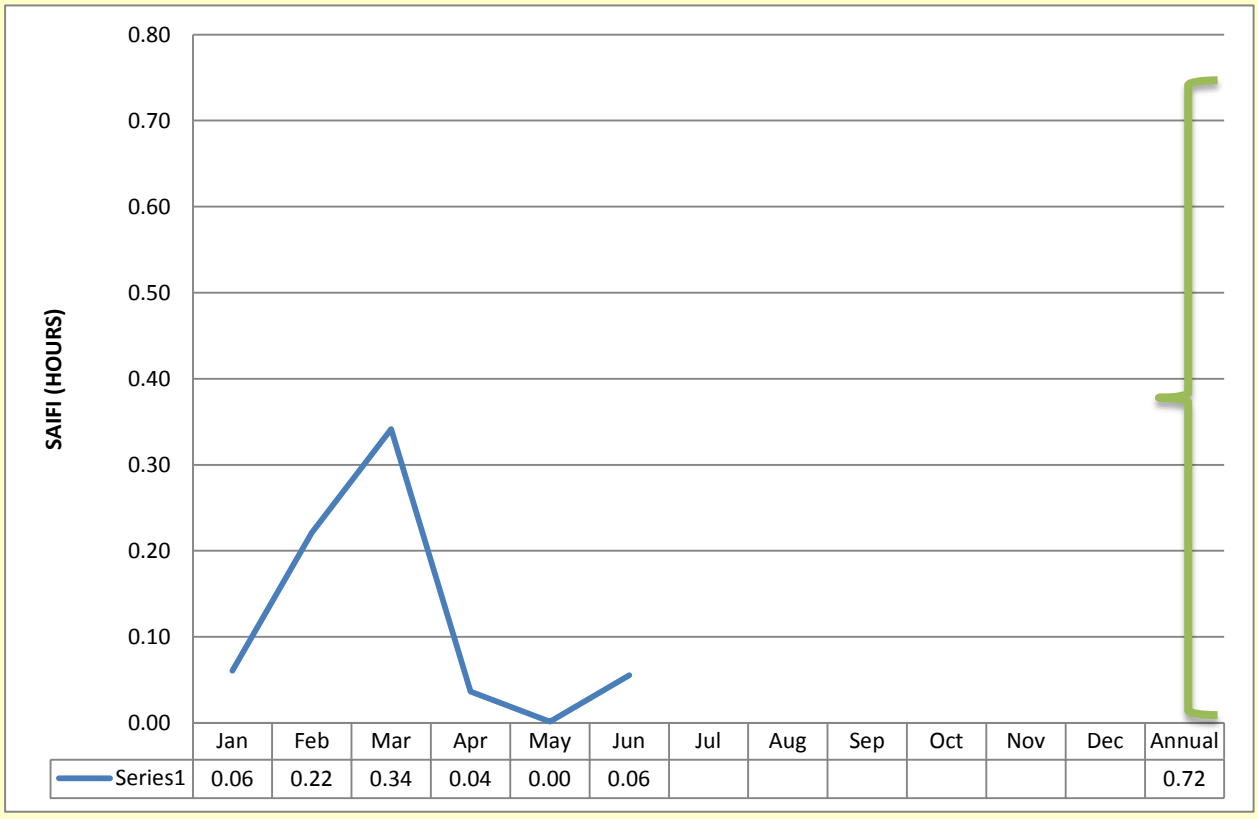
Excluding Loss of Supply

SAIFI is an indicator of the average number of interruptions each customer experiences. All planned and unplanned interruptions of one minute or more are used to calculate this index. It is defined as the number of interruptions normalized per customer served, and is expressed as follows:

$$\text{SAIFI} = \frac{\text{Total Customer Interruptions}}{\text{Total Number of Customers Served}}$$

IHDSL is required to remain, at minimum, within the range of our historical 3-year performance.

The range for the period 2009 to 2011 is: 0 to .74 hours; therefore, IHDSL has remained within the range for 2012 to-date.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Series1	0.06	0.22	0.34	0.04	0.00	0.06							0.72

Customer Average Interruption Duration Index (CAIDI)

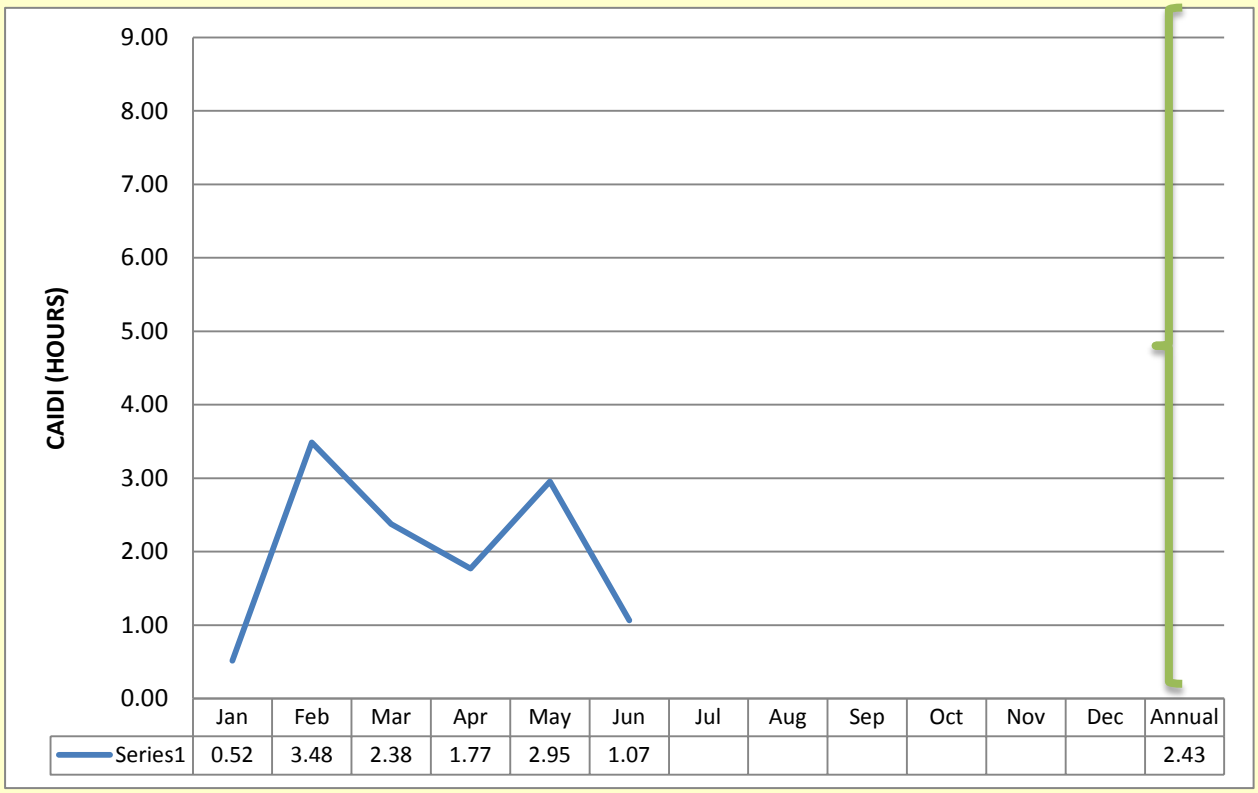
Excluding Loss of Supply

CAIDI is an indication of the speed at which power is restored. All planned and unplanned interruptions of one minute or more are used to calculate this index. It is defined as the average duration of interruptions in the year, and is expressed as follows:

$$\text{CAIDI} = \frac{\text{System Average Interruption Duration Index (SAIDI)}}{\text{System Average Interruption Frequency Index (SAIFI)}}$$

IHDSL is required to remain, at minimum, within the range of our historical 3-year performance.

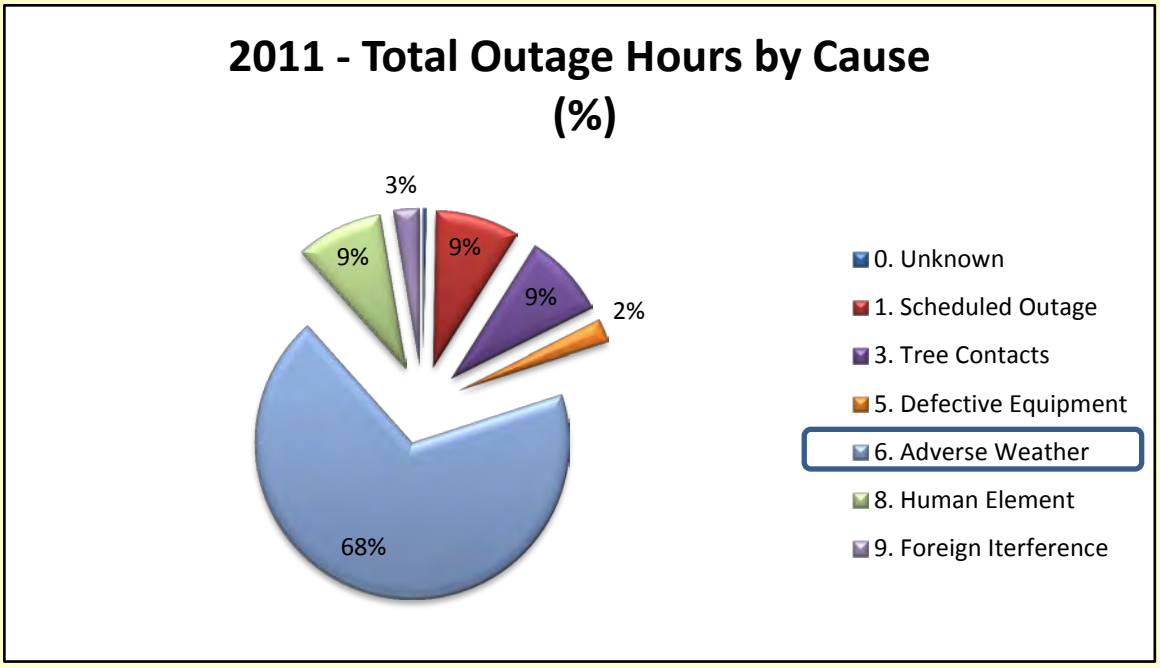
The range for the period 2009 to 2011 is: .15 to 9.97 hours; therefore, IHDSL has remained within the range for 2012 to-date.

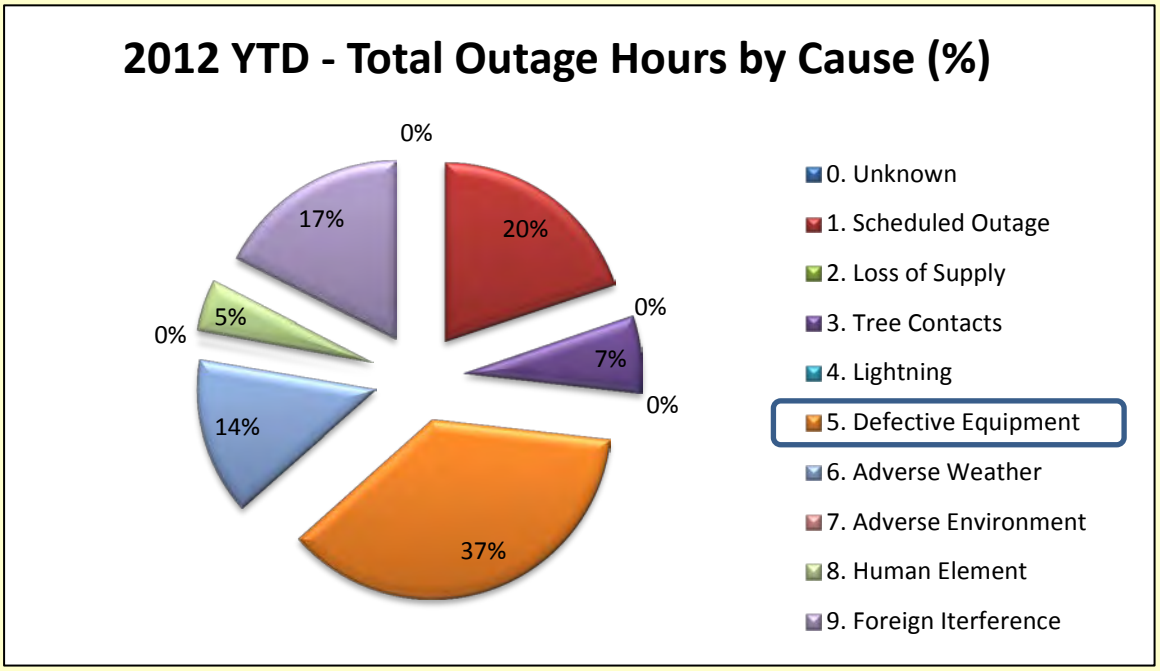


	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Series1	0.52	3.48	2.38	1.77	2.95	1.07							2.43

Service Interruption
by Cause (percentage)

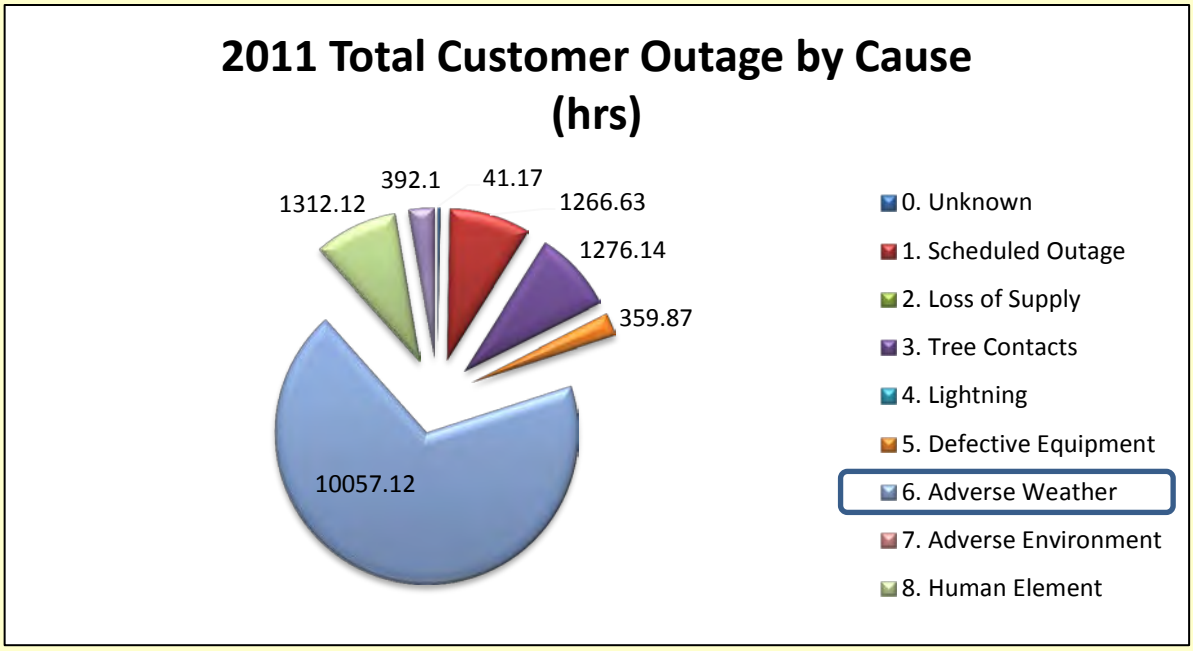
The following graphs show the breakdown of causes of customer outages, excluding Loss of Supply.

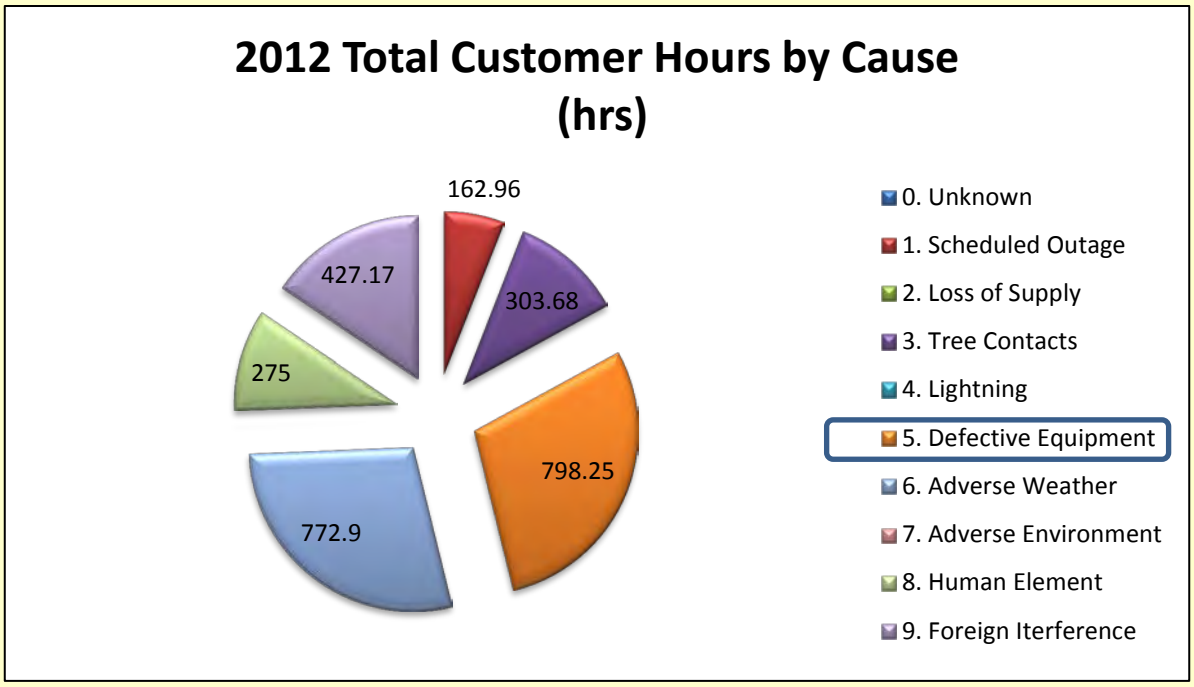




Service Interruption
by Cause (hours)

The following graphs show the breakdown of cause of customer outages, excluding Loss of Supply.

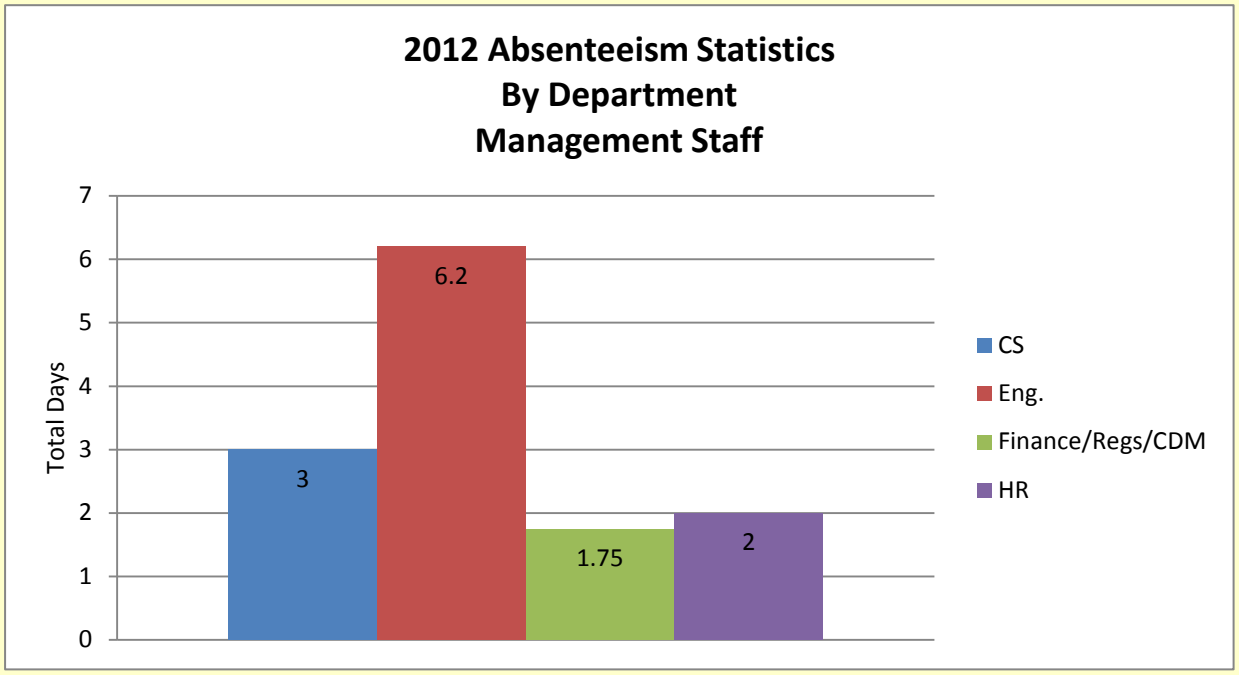


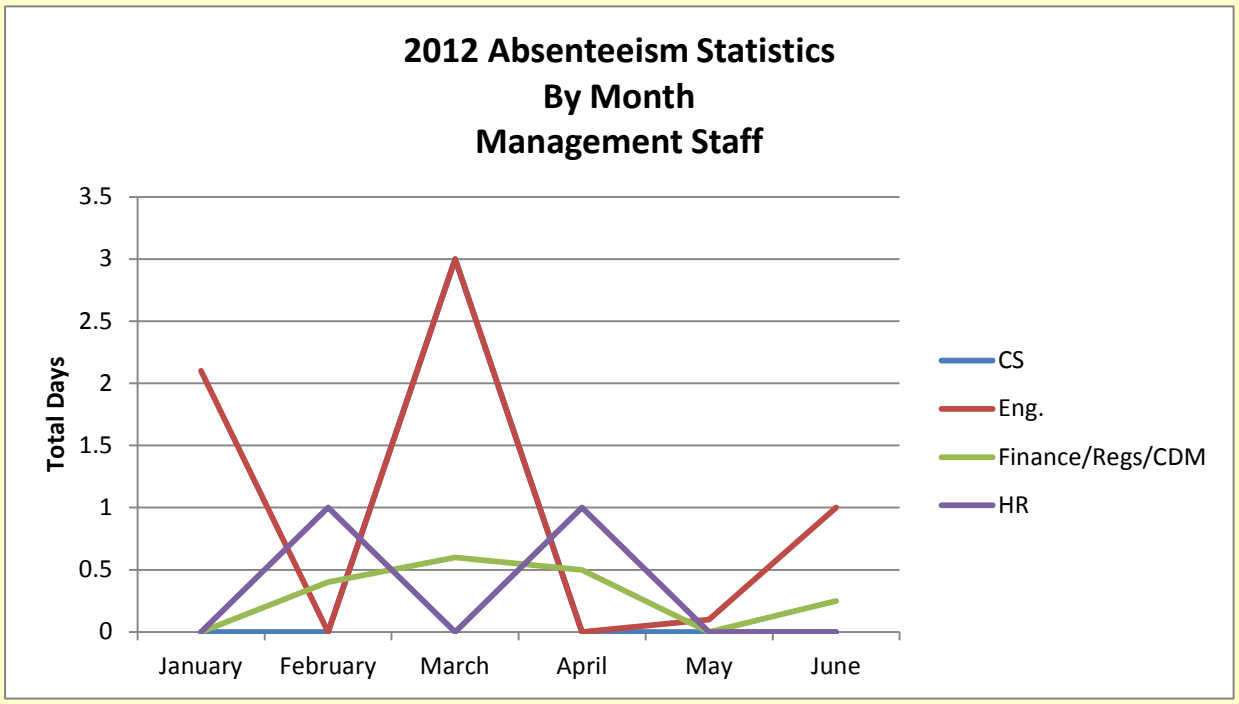


Human Resources

Absenteeism Statistics – 2012 To Date

Management Staff

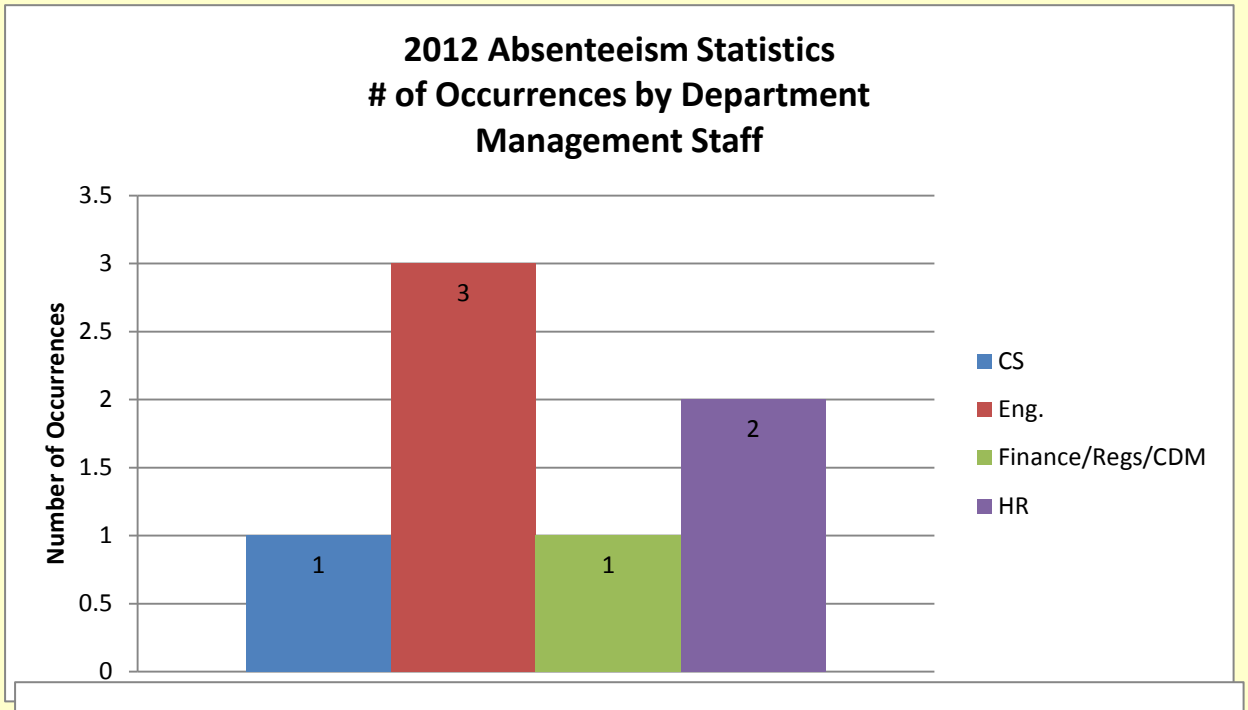


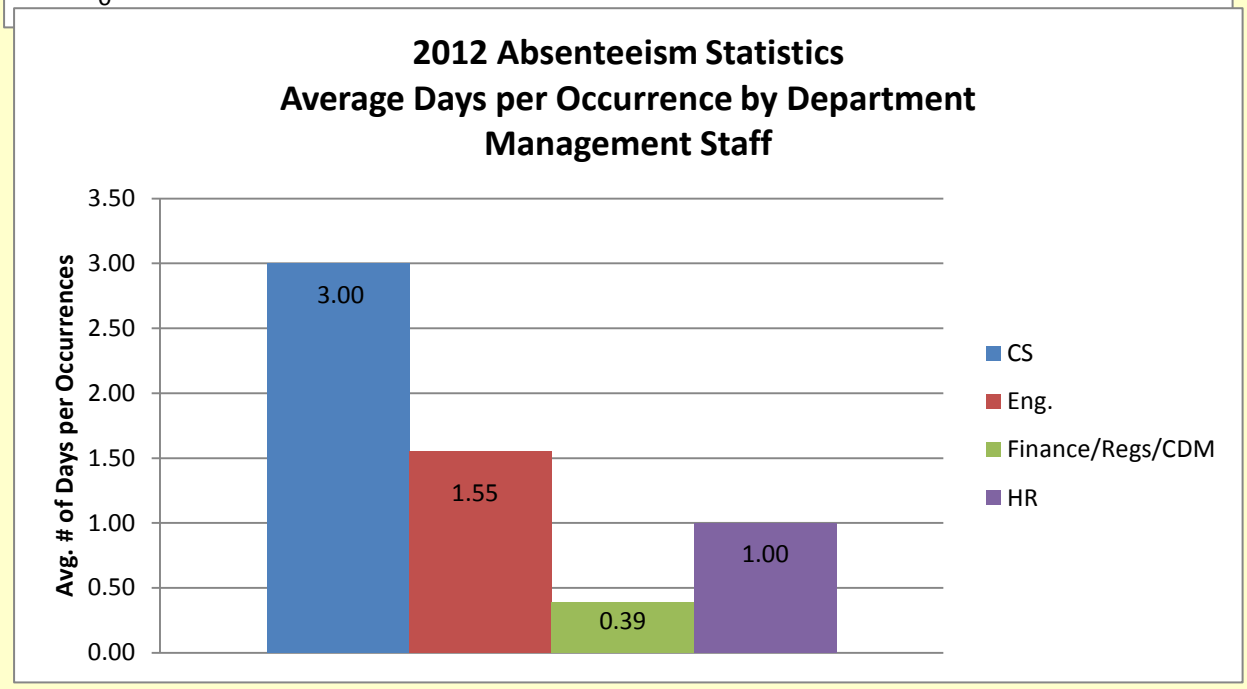


Human Resources

Absenteeism Statistics – 2012 To-Date

Management Staff

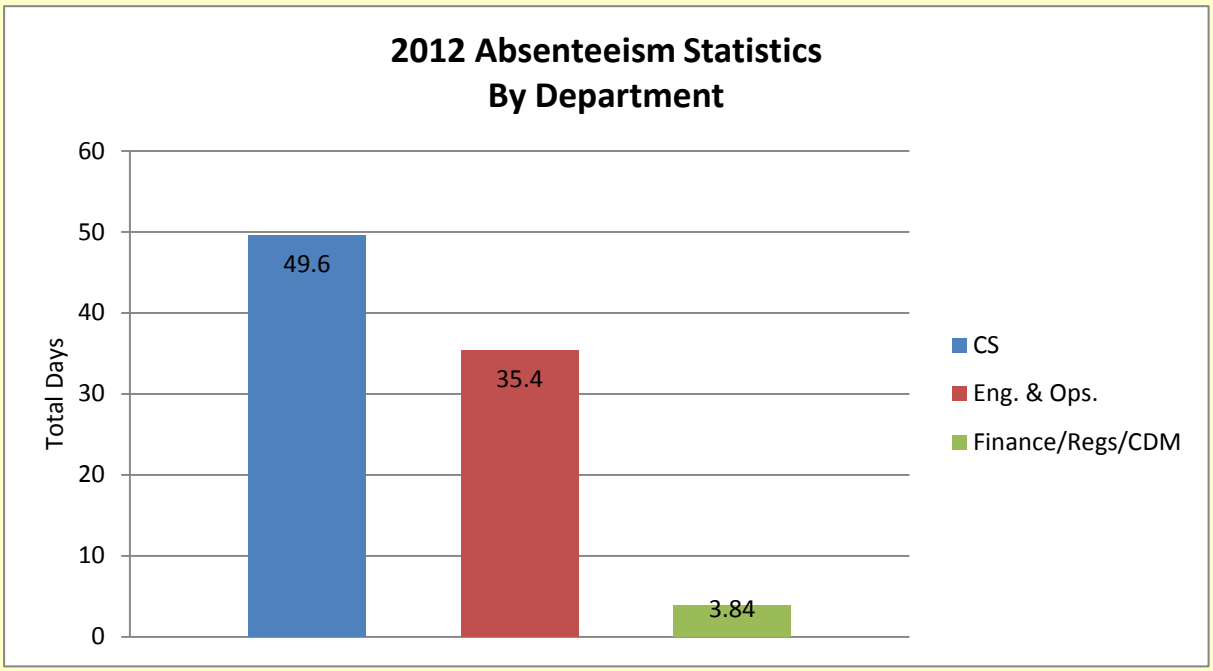


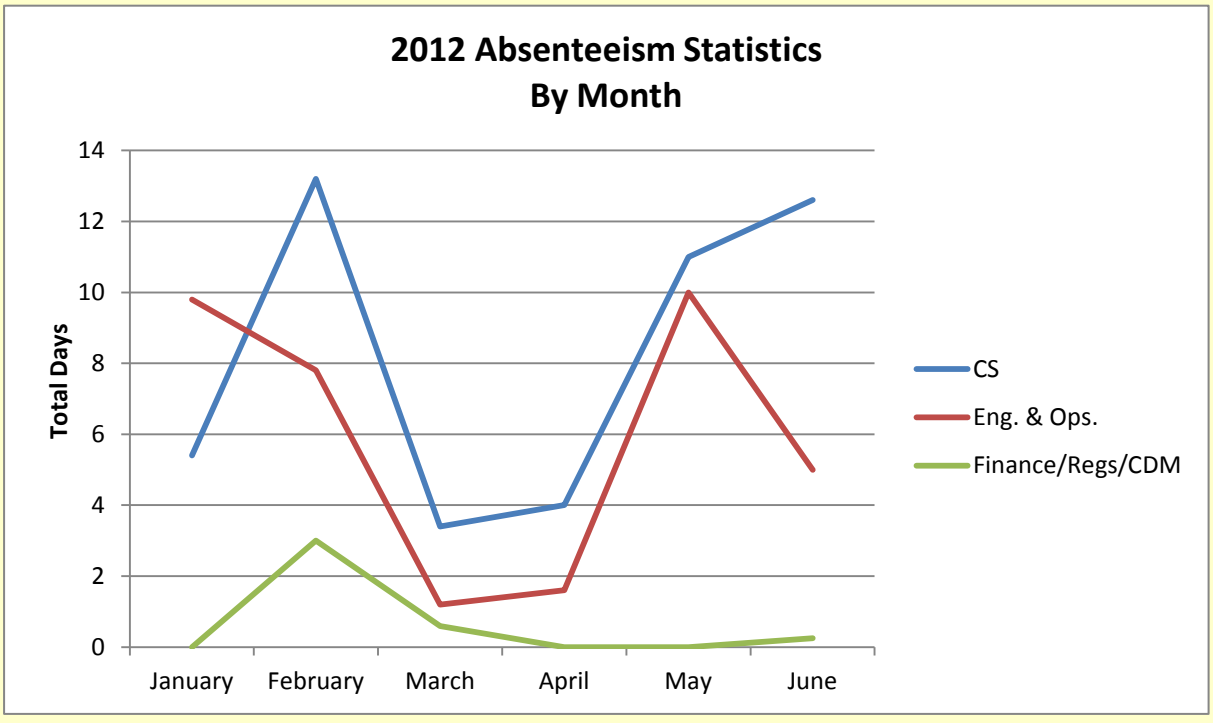


Human Resources

Absenteeism Statistics – 2012 To-Date

Unionized Staff

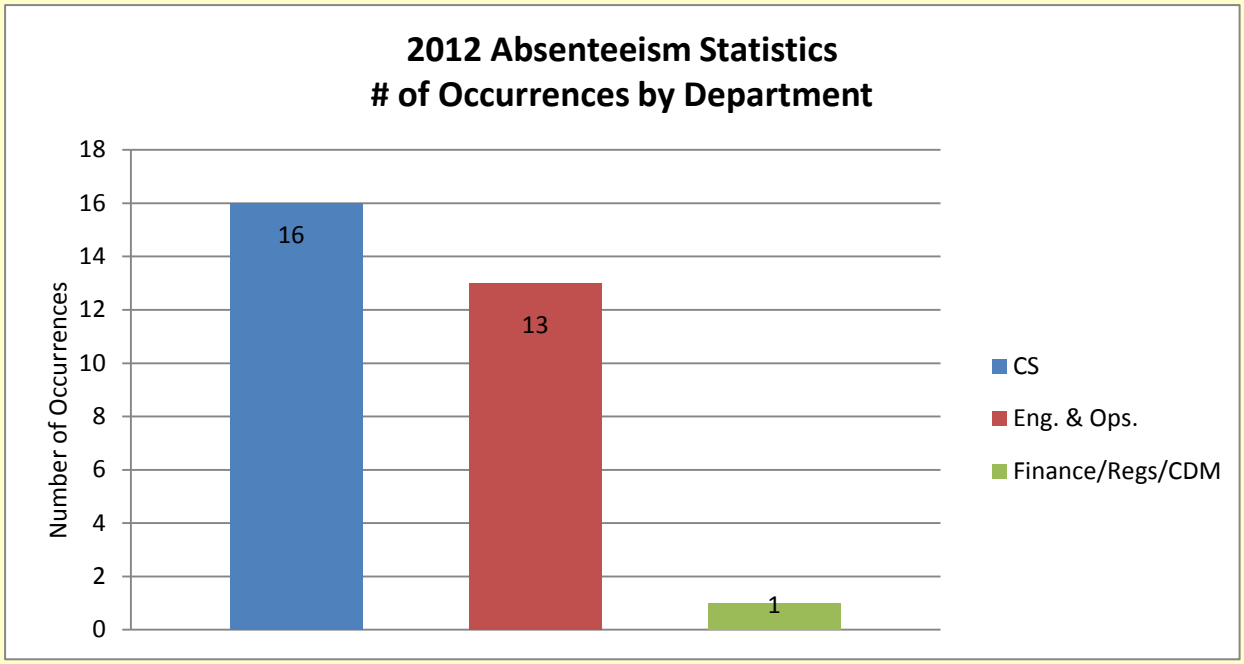


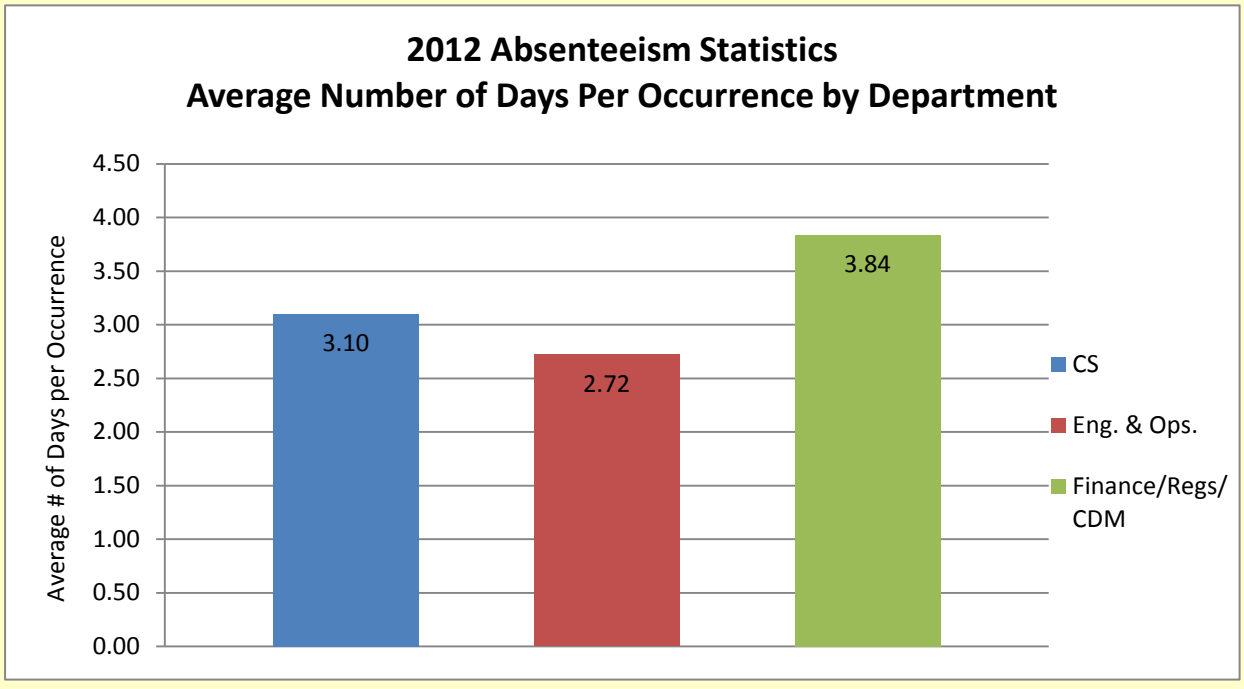


Human Resources

Absenteeism Statistics – 2012 To-Date

Unionized Staff





CDM Quarterly

Unverified Progress To Targets 2012:

IHDSL Target 2011 - 2014	Q1	Q3	Q3	Q4	YTD
Demand Savings: 2.5 MW	8.6%				
Energy Savings: 9.2 GWH	20.1%				

Note:

Results are not verified until September of the following year.

Q1 - 2012 OPA Results

All results are NET and presented at the end-user level

#	Initiative	Activity			Net Peak Demand Savings (kW)			Net Energy Savings (kWh)		
		Unit	Incremental (Current Quarter)	Program-to-Date (2011-to-Date):	Incremental (Current Quarter)	YTD Incremental (2012-to-Date)	Program-to-Date: unverified annual savings in 2014	Incremental (Current Quarter)	YTD Incremental (2012-to-Date)	Program-to-Date: unverified cumulative savings in 2014
Consumer Program										
1	Appliance Retirement	Appliances	12	243	1	1	20	7,103	7,103	550,106
2	Appliance Exchange	Appliances	0	7	0	0	0	0	0	2,091
3	HVAC Incentives	Equipment	25	148	6	6	34	9,385	9,385	210,030
4	Conservation Instant Coupon Booklet	Coupons	0	776	0	0	1	0	0	186,217
5	Bi-Annual Retailer Event	Coupons	0	1,571	0	0	3	0	0	310,493
6	Retailer Co-op	Items	0	0	0	0	0	0	0	0
7	***peaksaver*®** extension	Devices	0	234	0	0	131	0	0	20,592
8	Midstream Electronics	Items			not in market					
9	Midstream Pool Equipment	Items			not in market					
10	Residential New Construction	Houses	0	0	0.00	0.00	0	0	0	0
Consumer Program Total					**7**	**7**	**189**	**16,488**	**16,488**	**1,279,529**
Business Program										
11	Equipment Replacement Incentive	Projects	4	5	2	2	2	11,092	11,092	156,787
12	Direct Installed Lighting	Projects	0	10	0	0	6	0	0	169,493
13	Direct Service Space Cooling	Equipment			not in market					
14	Building Commissioning	Buildings	0	0	0	0	0	0	0	0
15	New Construction	Buildings	0	0	0	0	0	0	0	0
16	***peaksaver*®** extension	Devices	0	5	0	0	3	0	0	130
17	Demand Response 1	Facilities	0	0	0	0	0	0	0	0
18	Demand Response 3	Facilities	0	0	0	0	0	0	0	0
Business Program Total					**2**	**2**	**11**	**11,092**	**11,092**	**326,410**
Industrial Program										
19	Process & System Upgrades	Projects	0	0	0	0	0	0	0	0
20	Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0
21	Energy Manager	Managers	0	0	0	0	0	0	0	0
22	Equipment Replacement Incentive	Projects	2	2	4	4	4	9,300	9,300	27,901
23	Demand Response 1	Facilities	0	0	0	0	0	0	0	0
24	Demand Response 3	Facilities	0	0	0	0	0	0	0	0
Industrial Program Total					**4**	**4**	**4**	**9,300**	**9,300**	**27,901**
Home Assistance Program										
25	Home Assistance Program	Units	0	0	0	0	0	0	0	0
Home Assistance Program Total					**0**	**0**	**0**	**0**	**0**	**0**
Pre-2011 Programs completed in 2011										
25	Electricity Retrofit Incentive Program	Projects	0	0	0	0	0	0	0	0
26	High Performance New Construction	Projects	0	0	2	2	11	12,023	12,023	218,381
27	Toronto Comprehensive	Projects	0	0	0	0	0	0	0	0
28	Multifamily Energy Efficiency Rebates	Projects	0	0	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total					**2**	**2**	**11**	**12,023**	**12,023**	**218,381**
OPA-Contracted Province-Wide Portfolio Total					**15**	**15**	**215**	**48,903**	**48,903**	**1,852,221**
Unverified Savings Target Achieved:							**8.6%**			**20.1%**

FINANCIAL

IHDSL
Operating results
as of March 31, 2012

Monthly				Actual vs %		
	Actual	Prior Yr	Budget	Pr	Budget	
Distribution Revenue	620,589	827,437	833,990	75.0%	74.4%	
Other Revenue	(8,775)	61,954	41,316	-14.2%	-21.2%	
Expenses	428,534	563,516	564,478	76.0%	75.9%	
Earnings from operations	183,279	325,875	310,828	56.2%	59.0%	
NI after tax and interest	86,466	190,959	182,467	45.3%	47.4%	
Distribution plant capital	492,173	200,468	259,449	245.5%	189.7%	
General plant capital	8,180	47,348	62,629	17.3%	13.1%	
Total capital expenditures	500,353	247,816	322,078	201.9%	155.4%	
Total DVA	21,310	62,350	695	34.2%	3066.1%	

Year to date				Actual vs %		2012
	Actual	Prior Yr	Budget	Pr	Budget	Budget
Distribution Revenue	1,952,743	2,105,334	2,123,900	92.8%	91.9%	7,780,700
Other Revenue	77,930	147,503	123,948	52.8%	62.9%	495,800
Expenses	1,306,116	1,517,841	1,616,236	86.1%	80.8%	6,847,810
Earnings from operations	724,556	734,996	631,612	98.6%	114.7%	1,428,690
NI after tax and interest	387,584	404,849	324,756	95.7%	119.3%	486,690
Distribution plant capital	692,446	637,697	359,947	108.6%	192.4%	4,492,261
General plant capital	150,343	77,283	74,831	194.5%	200.9%	3,395,300
Total capital expenditures	842,789	714,980	434,778	117.9%	193.8%	7,887,561
Total DVA	(804,466)	51,638	(2,085)	-1557.9%	38583.5%	2,281,739

Financial Notes for Consideration:

Distribution revenues are down compared to prior year due to decreased load. This was the result of a warmer winter as seen in the following degree days report:

DEGREE DAYS (Celsius) CALCULATION - INNISFIL HYDRO

	2010-2011			2011-2012		
MONTH	**A**	**B**	**C**	**A**	**B**	**C**
SEPTEMBER	132	2.9%	-0.5%	99.7	3.1%	-32.7%
OCTOBER	301	6.6%	-19.9%	274	8.6%	-9.7%
NOVEMBER	465	10.2%	8.4%	414	13.0%	-12.2%
DECEMBER	772	16.9%	5.8%	604	19.0%	-27.9%
JANUARY	909	19.9%	8.9%	719	22.6%	-26.5%
FEBRUARY	737	16.1%	5.7%	638	20.0%	-15.6%
MARCH	**654**	**14.3%**	**23.8%**	**434**	**13.6%**	**-50.8%**
APRIL	384	8.4%	26.2%			
MAY	151	3.3%	1.5%			
JUNE	47	1.0%	-24.7%			
JULY	1	0.0%	-1242.9%			
AUGUST	15	0.3%	-5.3%			
TOTALS	4568	100.0%	8.4%	3182	100.0%	-43.5%

A - Degree Day *NOTE: New data source at this time and going forward.*

B - % of heating season for year to date

C - % change in degree days from same month, previous year

\+ = % colder over previous year

\- = % warmer over previous year

Other revenue is down mainly due to the effect of losses from capital dispositions.

Expenses are also lower in distribution and billing and collecting for reasons including:

- the Engineering Manager vacancy,
- timing of tree trimming cycles,
- reduced maintenance of underground conductor faults,
- lower bad debt expense, and
- lower meter reading costs (which were being reflected in variance accounts until disposition in May, when the full effect will be seen in the expense and capital accounts).

Depreciation expense (reflected in Expenses) is also lower due to the implementation of new useful lives of our capital assets based on the Kinetrics study supplied by the OEB.

ALLOWANCE FOR WORKING CAPITAL

In accordance with the Ontario Energy Board's letter dated April 12, 2012 " *RE: Update to Chapter 2 of the Filing Requirements for Transmission and Distribution Applications – Allowance for Working Capital*", IHDSL has incorporated the default value of 13% as the Allowance Approach for Working Capital on the following basis:

> The 13% Allowance Approach is calculated to be 13% of the sum of Cost of Power and controllable expenses (i.e. Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General).
>
> The commodity price estimate used to calculate the Cost of Power is based on the split between RPP and non-RPP customers on actual data. The calculation reflects the most recent Uniform Transmission Rates approved by the Board (EB-2011-0268), issued on December 20, 2011 and effective January 1, 2012. In the event new Uniform Transmission Rates are approved by the Board before finalization of this Rate Application, the commodity price estimate will be recalculated to reflect those new rates.

Overview and Calculation by Account:

IHDSL's working capital allowance is forecast to be $3,863,036 for 2013 based on the methodology outlined on page 19 of the Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 22, 2012. Namely, 13% of the sum of Cost of Power and Controllable Expenses (Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General), as illustrated on Table 4.1 below. IHDSL has provided a spreadsheet setting out IHDSL's Cost of Power calculations as Appendix B.

Table 4.1 - Working Capital Calculation

WORKING CAPITAL ALLOWANCE FOR 2013		
Distribution Expenses		
Distribution Expenses - Operation		1,423,862
Distribution Expenses - Maintenance		713,650
Billing and Collecting		1,106,020
Community Relations		23,900
Administrative and General Expenses		2,197,640
Taxes Other than Income Taxes		12,500
Total Eligible Distribution Expenses		**5,477,572**
Power Supply Expenses		24,238,088
Total Working Capital Expenses		29,715,660
Working Capital Allowance @	13.00%	3,863,036

CONVERSION TO MODIFIED INTERNATIONAL FINANCIAL REPORTING STANDARDS (MIFRS)

The conversion from Canadian Generally Accepted Accounting Principles (CGAAP) to Modified International Financial Reporting Standards (MIFRS) has resulted in a number changes to IHDSL's accounting for Plant Property and Equipment (PP&E).

Conversion to MIFRS: Impact on Fixed Assets

IHDSL has elected to take the IFRS 1 Exemption for rate regulated entities, which allows the use of the net book value of assets as at the date of transition as the deemed cost of the asset. This change has been reflected in the continuity statements provided below for the 2012 Bridge year (Table 5.1) and the 2013 Test year (Table 5.2). The opening balance of the gross fixed assets for the 2012 Bridge year is the net book value of the assets for the same date under CGAAP.

Componentization and Amortization

IAS 16 requires each part of an item of PP&E with a cost that is significant in relation to the total cost of the time to be depreciated separately. In addition IAS 16 requires that entities perform a review of its useful lives, amortization methods and residual values on an annual basis.

IHDSL has reviewed the useful life of its assets with the aid of the Kinetrics report. Exhibit 4, Tab 4, Schedule 2 outlines the amortization expense based on the new useful lives of the assets.

IHDSL has restated its continuity statements for the 2012 Bridge year and the 2013 Test year to include these changes.

IAS 16 – Property, Plant and Equipment – Measurement after Recognition.

For subsequent periods following the initial recognition of an asset, IAS 16 permits the choice of using either the Cost Model or the Revaluation Model for valuing PP&E. IHDSL will continue to use the Cost Model to measure PP&E.

Table 5.1: Continuity Statement – 2012 Bridge Year (MIFRS)

Year 2012

CCA Class	OEB	Description	Depreciation Rate	Cost				Accumulated Depreciation				Net Book Value
				Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	
12	1611	Computer Software (Formally known as Account 1925)		$ 363,599	$ 282,150		$ 645,749	-$ 238,982	-$ 113,920		-$ 352,902	$ 292,847
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ 273,770	$ 465,000		$ 738,770	$ -			$ -	$ 738,770
CEC	1806	Land Rights		$ 982,703			$ 982,703	-$ 557,986	-$ 14,872		-$ 572,858	$ 409,845
47	1808	Buildings		$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ 86,252			$ 86,252	-$ 34,500	-$ 3,312		-$ 37,812	$ 48,440
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 4,358,561	$ 35,448		$ 4,394,009	-$ 2,322,876	-$ 90,878		-$ 2,413,754	$ 1,980,255
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 9,077,888	$ 1,172,023	-$ 100,000	$ 10,149,911	-$ 4,286,653	-$ 187,013	$ 85,000	-$ 4,388,666	$ 5,761,245
47	1835	Overhead Conductors & Devices		$ 13,192,946	$ 1,314,249	-$ 150,000	$ 14,357,195	-$ 7,476,921	-$ 147,438	$ 127,500	-$ 7,496,859	$ 6,860,336
47	1840	Underground Conduit		$ 2,035,571	$ 37,200		$ 2,072,771	-$ 487,767	-$ 48,744		-$ 536,511	$ 1,536,260
47	1845	Underground Conductors & Devices		$ 11,721,156	$ 454,700	-$ 50,000	$ 12,125,856	-$ 4,339,016	-$ 316,093	$ 42,500	-$ 4,612,609	$ 7,513,247
47	1850	Line Transformers		$ 8,602,786	$ 545,110	-$ 10,000	$ 9,137,896	-$ 5,587,946	-$ 206,644	$ 8,500	-$ 5,786,090	$ 3,351,806
47	1855	Services (Overhead & Underground)		$ 4,017,136	$ 207,405		$ 4,224,541	-$ 1,757,180	-$ 79,751		-$ 1,836,931	$ 2,387,610
47	1860	Meters		$ 287,258			$ 287,258	-$ 67,036	-$ 11,490		-$ 78,526	$ 208,732
47	1860	Meters (Smart Meters)		$ 2,162,281	$ 74,240		$ 2,236,521	-$ 327,495	-$ 146,622		-$ 474,117	$ 1,762,404
47	1875	Street Lighting		$ 7,646		-$ 7,646	$ -	-$ 2,670		$ 2,670	$ -	$ -
N/A	1905	Land		$ 201,049			$ 201,049	$ -			$ -	$ 201,049
47	1908	Buildings & Fixtures		$ 739,631	$ 2,025,000		$ 2,764,631	-$ 273,912	-$ 28,866		-$ 302,778	$ 2,461,853
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 308,655	$ 25,500		$ 334,155	-$ 232,648	-$ 12,536		-$ 245,184	$ 88,971
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 515,306	$ 122,500		$ 637,806	-$ 400,081	-$ 62,665		-$ 462,746	$ 175,060
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 1,174,196			$ 1,174,196	-$ 460,134	-$ 159,800		-$ 619,934	$ 554,262
8	1935	Stores Equipment		$ 31,824	$ 4,000		$ 35,824	-$ 18,172	-$ 1,954		-$ 20,126	$ 15,698
8	1940	Tools, Shop & Garage Equipment		$ 487,684	$ 27,000		$ 514,684	-$ 188,237	-$ 32,112		-$ 220,349	$ 294,335
8	1945	Measurement & Testing Equipment		$ 32,997	$ 8,500		$ 41,497	-$ 14,226	-$ 2,631		-$ 16,857	$ 24,640
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ 1,407,393	$ 367,850		$ 1,775,243	-$ 789,059	-$ 97,267		-$ 886,326	$ 888,917
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 7,714,946	-$ 1,083,954		-$ 8,798,900	$ 1,570,218	$ 225,382		$ 1,795,600	-$ 7,003,300
	etc.			$ -			$ -				$ -	$ -
				$ -								
		Total		**$ 54,353,342**	**$ 6,083,921**	**-$ 317,646**	**$ 60,119,617**	**-$ 28,293,279**	**-$ 1,539,226**	**$ 266,170**	**-$ 29,566,335**	**$ 30,553,282**
												$ 30,628,282

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 159,800
Stranded Meters	$ 43,000
Net Depreciation	-$ 1,422,426

Table 5.2: Continuity Statement – 2013 Test Year (MIFRS)

Year 2013

CCA Class	OEB	Description	Depreciation Rate	Cost				Accumulated Depreciation				Net Book Value
				Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	
12	1611	Computer Software (Formally known as Account 1925)		$ 645,749	$ 278,500		$ 924,249	-$ 352,902	-$ 174,811		-$ 527,713	$ 396,536
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ 738,770			$ 738,770	$ -			$ -	$ 738,770
CEC	1806	Land Rights		$ 982,703			$ 982,703	-$ 572,858	-$ 14,575		-$ 587,433	$ 395,270
47	1808	Buildings		$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ 86,252			$ 86,252	-$ 37,812	-$ 3,312		-$ 41,124	$ 45,128
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 4,394,009	$ 194,422		$ 4,588,431	-$ 2,413,754	-$ 93,752		-$ 2,507,506	$ 2,080,925
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 10,149,911	$ 918,153	-$ 105,000	$ 10,963,064	-$ 4,388,666	-$ 210,238	$ 89,250	-$ 4,509,654	$ 6,453,410
47	1835	Overhead Conductors & Devices		$ 14,357,195	$ 1,123,543	-$ 157,500	$ 15,323,238	-$ 7,496,859	-$ 167,753	$ 133,875	-$ 7,530,737	$ 7,792,501
47	1840	Underground Conduit		$ 2,072,771	$ 38,205		$ 2,110,976	-$ 536,511	-$ 49,686		-$ 586,197	$ 1,524,779
47	1845	Underground Conductors & Devices		$ 12,125,856	$ 157,573	-$ 52,500	$ 12,230,929	-$ 4,612,609	-$ 323,746	$ 44,625	-$ 4,891,730	$ 7,339,199
47	1850	Line Transformers		$ 9,137,896	$ 649,500	-$ 10,500	$ 9,776,896	-$ 5,786,090	-$ 221,577	$ 8,925	-$ 5,998,742	$ 3,778,154
47	1855	Services (Overhead & Underground)		$ 4,224,541	$ 216,912		$ 4,441,453	-$ 1,836,931	-$ 83,994		-$ 1,920,925	$ 2,520,528
47	1860	Meters		$ 287,258			$ 287,258	-$ 78,526	-$ 11,490		-$ 90,016	$ 197,242
47	1860	Meters (Smart Meters)		$ 2,236,521	$ 116,170		$ 2,352,691	-$ 474,117	-$ 152,968		-$ 627,085	$ 1,725,606
47	1875	Street Lighting		$ -			$ -	$ -			$ -	$ -
N/A	1905	Land		$ 201,049			$ 201,049	$ -			$ -	$ 201,049
47	1908	Buildings & Fixtures		$ 2,764,631	$ 5,127,500		$ 7,892,131	-$ 302,778	-$ 100,391		-$ 403,169	$ 7,488,962
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 334,155	$ 35,000		$ 369,155	-$ 245,184	-$ 15,561		-$ 260,745	$ 108,410
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 637,806	$ 128,000		$ 765,806	-$ 462,746	-$ 75,182		-$ 537,928	$ 227,878
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 1,174,196	$ 110,000		$ 1,284,196	-$ 619,934	-$ 170,800		-$ 790,734	$ 493,462
8	1935	Stores Equipment		$ 35,824	$ 4,200		$ 40,024	-$ 20,126	-$ 2,364		-$ 22,490	$ 17,534
8	1940	Tools, Shop & Garage Equipment		$ 514,684	$ 20,000		$ 534,684	-$ 220,349	-$ 34,462		-$ 254,811	$ 279,873
8	1945	Measurement & Testing Equipment		$ 41,497	$ 19,000		$ 60,497	-$ 16,857	-$ 4,006		-$ 20,863	$ 39,634
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ 1,775,243	$ 266,697		$ 2,041,940	-$ 886,326	-$ 118,418		-$ 1,004,744	$ 1,037,196
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 8,798,900	-$ 382,523		-$ 9,181,423	$ 1,795,600	$ 246,332		$ 2,041,932	-$ 7,139,491
	etc.			$ -			$ -				$ -	$ -
				$ -								
		Total		**$ 60,119,617**	**$ 9,020,852**	**-$ 325,500**	**$ 68,814,969**	**-$ 29,566,335**	**-$ 1,782,754**	**$ 276,675**	**-$ 31,072,414**	**$ 37,742,555**
												$ 37,817,555

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 170,800
Stranded Meters	
Net Depreciation	-$ 1,611,954

COST OF POWER

IHDSL has calculated cost of power for the 2012 Bridge Year and 2013 Test Year based on the results of the load forecast which is discussed in detail in Exhibit 3. The electricity prices used in the calculation were the published prices in the OEB's Regulated Price Plan Report – May 1, 2012 to April 30, 2013, issued April 2, 2012. IHDSL will update the electricity prices should the OEB publish a revised Regulated Price Plan Report prior to a Decision.

The Cost of Power calculations for the 2012 Bridge Year and a cost of power summary are provided in the following Table 2.4.2 a nd Table 2.4.3 r espectively. The cost of power calculations for the 2013 Test Year and a cost of power summary are provided in the following Table 2.4.4 and Table 2.4.5 respectively. No changes to the Cost of Power calculations are made as a result of the transition to MIFRS.

Table 2.4.2 Cost of Power Forecast Calculation – 2012 Bridge Year

2012 Load Foreacst	**kWh**	**kW**	**2011 %RPP**
Residential	147,749,853		89%
General Service < 50 kW	30,870,769		82%
General Service 50 to 4,999 kW	50,262,876	144,598	5%
Street Lighting	1,481,108	4,329	0%
Sentinel Lighting	107,147	298	89%
Unmetered Scattered Load	538,257		89%
TOTAL	**231,010,011**	**149,224**	

Electricity - Commodity RPP	**2012**	**2012 Loss**			
Class per Load Forecast RPP	**Forecasted**	**Factor**	**2012**		
Residential	130,843,805	1.0746	140,604,752	$0.08069	$11,345,397
General Service < 50 kW	25,432,016	1.0746	27,329,245	$0.08069	$2,205,197
General Service 50 to 4,999 kW	2,284,095	1.0746	2,454,488	$0.08069	$198,053
Street Lighting	0	1.0746	0	$0.08069	$0
Sentinel Lighting	95,106	1.0746	102,201	$0.08069	$8,247
Unmetered Scattered Load	478,963	1.0746	514,694	$0.08069	$41,531
TOTAL	**159,133,985**		**171,005,380**		**$13,798,424**

Table 2.4.2 Cost of Power Forecast Calculation – 2012 Bridge Year (cont'd)

Electricity - Commodity RPP	**2012**	**2012 Loss**			
Class per Load Forecast RPP	**Forecasted**	**Factor**	**2012**		
Residential	130,843,805	1.0746	140,604,752	$0.08069	$11,345,397
General Service < 50 kW	25,432,016	1.0746	27,329,245	$0.08069	$2,205,197
General Service 50 to 4,999 kW	2,284,095	1.0746	2,454,488	$0.08069	$198,053
Street Lighting	0	1.0746	0	$0.08069	$0
Sentinel Lighting	95,106	1.0746	102,201	$0.08069	$8,247
Unmetered Scattered Load	478,963	1.0746	514,694	$0.08069	$41,531
TOTAL	**159,133,985**		**171,005,380**		**$13,798,424**

Electricity - Commodity Non-RPP	**2012**	**2012 Loss**			
Class per Load Forecast	**Forecasted**	**Factor**	**2012**		
Residential	16,906,049	1.0746	18,167,240	$0.07878	$1,431,215
General Service < 50 kW	5,438,753	1.0746	5,844,484	$0.07878	$460,428
General Service 50 to 4,999 kW	47,978,782	1.0746	51,557,999	$0.07878	$4,061,739
Street Lighting	1,481,108	1.0746	1,591,599	$0.07878	$125,386
Sentinel Lighting	12,041	1.0746	12,939	$0.07878	$1,019
Unmetered Scattered Load	59,294	1.0746	63,717	$0.07878	$5,020
TOTAL	**71,876,026**		**77,237,978**		**$6,084,808**

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**	**2012**		
Residential		kWh	158,771,992	$0.0052	$825,614
General Service < 50 kW		kW	33,173,728	$0.0047	$155,917
General Service 50 to 4,999 kW		kW	144,598	$1.9280	$278,784
Street Lighting		kWh	4,329	$1.4540	$6,294
Sentinel Lighting		kW	298	$1.4614	$435
Unmetered Scattered Load		kW	578,411	$0.0047	$2,719
TOTAL					**$1,269,763**

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**	**2012**		
Residential		kWh	158,771,992	$0.0041	$650,965
General Service < 50 kW		kW	33,173,728	$0.0038	$126,060
General Service 50 to 4,999 kW		kW	144,598	$1.4825	$214,366
Street Lighting		kWh	4,329	$1.1459	$4,960
Sentinel Lighting		kW	298	$1.1699	$348
Unmetered Scattered Load		kW	578,411	$0.0038	$2,198
TOTAL					**$998,898**

Wholesale Market Service					
Class per Load Forecast			**2012**		
Residential			158,771,992	$0.0052	$825,614
General Service < 50 kW			33,173,728	$0.0052	$172,503
General Service 50 to 4,999 kW			54,012,487	$0.0052	$280,865
Street Lighting			1,591,599	$0.0052	$8,276
Sentinel Lighting			115,140	$0.0052	$599
Unmetered Scattered Load			578,411	$0.0052	$3,008
TOTAL			**248,243,358**		**$1,290,865**

Rural Rate Assistance					
Class per Load Forecast			**2012**		
Residential			158,771,992	$0.0011	$174,649
General Service < 50 kW			33,173,728	$0.0011	$36,491
General Service 50 to 4,999 kW			54,012,487	$0.0011	$59,414
Street Lighting			1,591,599	$0.0011	$1,751
Sentinel Lighting			115,140	$0.0011	$127
Unmetered Scattered Load			578,411	$0.0011	$636
TOTAL			**248,243,358**		**$273,068**

LV		**Volume**			
Class per Load Forecast		**Metric(w/o loss**	**2012**		
Residential		kWh	147,749,853	$0.0022	$325,050
General Service < 50 kW		kWh	30,870,769	$0.0020	$61,742
General Service 50 to 4,999 kW		kW	144,598	$0.7883	$113,986
Street Lighting		kW	4,329	$1.6331	$7,069
Sentinel Lighting		kW	298	$0.6065	$181
Unmetered Scattered Load		kWh	538,257	$0.0020	$1,077
TOTAL			**179,308,103**		**$509,104**

Table 2.4.3 Cost of Power Summary – 2012 Bridge Year

Summary	2012
4705-Power Purchased	$19,883,232
SME	$72,133
4708-Charges-WMS	$1,290,865
4714-Charges-NW	$1,269,763
4716-Charges-CN	$998,898
4730-Rural Rate Assistance	$273,068
4750-Low Voltage	$509,104
TOTAL	**24,297,062**

Table 2.4.4 Cost of Power Forecast Calculation – 2013 Test Year

2013 Load Foreacst	**kWh**	**kW**	**2011 %RPP**		
Residential	146,562,898		89%		
General Service < 50 kW	31,437,455		82%		
General Service 50 to 4,999 kW	50,917,130	146,480	5%		
Street Lighting	1,505,545	4,400	0%		
Sentinel Lighting	104,161	289	89%		
Unmetered Scattered Load	592,220		89%		
TOTAL	**231,119,409**	**151,169**			

Electricity - Commodity RPP	**2013**	**2013 Loss**			
Class per Load Forecast RPP	**Forecasted**	**Factor**	**2013**		
Residential	129,792,665	1.0714	139,062,222	$0.08069	$11,220,931
General Service < 50 kW	25,898,864	1.0714	27,748,514	$0.08069	$2,239,028
General Service 50 to 4,999 kW	2,313,826	1.0714	2,479,075	$0.08069	$200,037
Street Lighting	0	1.0714	0	$0.08069	$0
Sentinel Lighting	92,456	1.0714	99,059	$0.08069	$7,993
Unmetered Scattered Load	526,982	1.0714	564,618	$0.08069	$45,559
TOTAL	**158,624,793**		**169,953,488**		**$13,713,547**

Electricity - Commodity Non-RPP	**2013**	**2013 Loss**			
Class per Load Forecast	**Forecasted**	**Factor**	**2013**		
Residential	16,770,233	1.0714	17,967,933	$0.07877	$1,415,334
General Service < 50 kW	5,538,590	1.0714	5,934,146	$0.07877	$467,433
General Service 50 to 4,999 kW	48,603,304	1.0714	52,074,464	$0.07877	$4,101,906
Street Lighting	1,505,545	1.0714	1,613,068	$0.07877	$127,061
Sentinel Lighting	11,705	1.0714	12,541	$0.07877	$988
Unmetered Scattered Load	65,238	1.0714	69,897	$0.07877	$5,506
TOTAL	**72,494,616**		**77,672,051**		**$6,118,227**

Table 2.4.4 Cost of Power Forecast Calculation – 2013 Test Year (cont'd)

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**	**2013**		
Residential		kWh	157,030,155	$0.0050	$816,557
General Service < 50 kW		kWh	33,682,661	$0.0046	$158,309
General Service 50 to 4,999 kW		kW	146,480	$1.8708	$282,413
Street Lighting		kW	4,400	$1.4180	$6,398
Sentinel Lighting		kW	289	$1.4109	$423
Unmetered Scattered Load		kWh	634,515	$0.0046	$2,982
TOTAL					**$1,267,081**

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**	**2013**		
Residential		kWh	157,030,155	$0.0040	$643,824
General Service < 50 kW		kWh	33,682,661	$0.0037	$127,994
General Service 50 to 4,999 kW		kW	146,480	$1.4516	$217,156
Street Lighting		kW	4,400	$1.6635	$5,042
Sentinel Lighting		kW	289	$1.1220	$339
Unmetered Scattered Load		kWh	634,515	$0.0037	$2,411
TOTAL					**$996,766**

Wholesale Market Service					
Class per Load Forecast			**2013**		
Residential			157,030,155	$0.0052	$816,557
General Service < 50 kW			33,682,661	$0.0052	$175,150
General Service 50 to 4,999 kW			54,553,539	$0.0052	$283,678
Street Lighting			1,613,068	$0.0052	$8,388
Sentinel Lighting			111,600	$0.0052	$580
Unmetered Scattered Load			634,515	$0.0052	$3,299
TOTAL			**247,625,539**		**$1,287,653**

Rural Rate Assistance					
Class per Load Forecast			**2013**		
Residential			157,030,155	$0.0011	$172,733
General Service < 50 kW			33,682,661	$0.0011	$37,051
General Service 50 to 4,999 kW			54,553,539	$0.0011	$60,009
Street Lighting			1,613,068	$0.0011	$1,774
Sentinel Lighting			111,600	$0.0011	$123
Unmetered Scattered Load			634,515	$0.0011	$698
TOTAL			**247,625,539**		**$272,388**

LV		**Volume**			
Class per Load Forecast		**Metric(w/o loss**	**2013**		
Residential		kWh	146,562,898	$0.0022	$322,438
General Service < 50 kW		kWh	31,437,455	$0.0020	$62,875
General Service 50 to 4,999 kW		kW	146,480	$0.7883	$115,470
Street Lighting		kW	4,400	$1.6331	$7,186
Sentinel Lighting		kW	289	$0.6065	$176
Unmetered Scattered Load		kWh	592,220	$0.0020	$1,184
TOTAL			**178,743,742**		**$509,329**

Table 2.4.5 Cost of Power Summary - 2013 Test Year

Summary	2013
4705-Power Purchased	$19,831,774
SME	$73,097
4708-Charges-WMS	$1,287,653
4714-Charges-NW	$1,267,081
4716-Charges-CN	$996,766
4730-Rural Rate Assistance	$272,388
4750-Low Voltage	$509,329
TOTAL	**24,238,088**

CONVERSION TO MIFRS: IMPACT ON CAPITALIZATION OF BURDENS

Overview:

The Canadian Accounting Standards Board ("AcSB") adopted a strategic plan that will have Canadian GAAP (CGAAP) transitioned to International Financial Reporting Standards (IFRS), effective January 1, 2013 and which will require entities to restate, for comparative purposes, their 2012 interim and annual financial statements and their opening 2013 financial position.

In October 2010, the AcSB approved the incorporation of IFRS into Part 1 of the Canadian Institute of Chartered Accountants ("CICA") Handbook for qualifying entities with activities subject to rate regulation. Part 1 of the CICA Handbook specifies that first-time adoption is mandatory for interim and annual financial statements relating to annual periods beginning on or after January 1, 2011. The AcSB has proposed that qualifying entities with rate regulated activities be permitted, but not required, to continue applying the accounting standards in Part V of the CICA Handbook for an additional two years. This amendment also requires entities that do not prepare their interim and annual financial statements in accordance with Part 1 of the Handbook during the annual period beginning on or after January 1, 2011 to disclose that fact.

IHDSL deferred implementation of IFRS to January 1, 2013.

Background: Each part of an item of property, plant and equipment (PP&E) with a cost that is significant in relation to the total cost of the item, shall be depreciated separately.

Using the Kinetrics Inc. Asset Amortization Study dated April 28, 2010, Report K-418022-RA-0001-R003, prepared for the Ontario Energy Board, IHDSL has adopted the Typical Useful Life (TUL) for fixed assets in accordance with this study. With respect to the useful lives, IHDSL does not have better data upon which to determine the TUL and experience has shown that the TUL in the report is closer to the actual useful lives being experienced, than under CGAAP.

Depreciation is to be calculated on the basis of the estimated useful life of the item after deducting its residual value when fully depreciated. In practice, the residual value of an asset is often insignificant and therefore immaterial in the calculation of the depreciable amount.

The residual value and the useful life of an asset shall be reviewed at least at each financial year-end and, if expectations differ from previous estimates, the change(s) shall be accounted for as a change in an accounting estimate in accordance with IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors.

Depreciation of an asset begins when it is available for use (i.e. when it is in the location and in the condition necessary for it to be capable of operating in the manner as intended). Depreciation of an asset ceases, at the earlier of the date that the asset is classified as held for Sale, in accordance with IFRS 5, and the date that the asset is derecognized

Standard IAS 16 – Property, Plant and Equipment (PP&E) states that the cost of an item of PP&E includes those costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. IAS 16 does not define the term "directly attributable". The specific facts and circumstances surrounding the nature of the costs and the activity associated with it must be considered to determine if it is directly attributable to an item of PP&E. Where CGAAP allowed for the capitalization of general and administrative overhead, IFRS does not.

IHDSL has reviewed the costs included within its burdens to determine which continue to be appropriate expenses to capitalize and which should be removed from the burden and directly expensed as part of OM&A.

As IHDSL did not record these burdened costs as capital there are no reductions in capital spending as a result of the transition to IFRS., thus no impact on the OM&A expense in 2013.

Appendix 2-D
Overhead Expense

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that are currently capitalized on self-constructed assets under MIFRS or an alternate accounting

Nature of the Overhead Costs	(A) [1] Dollar Impact on PP&E Historic Year	(B) Dollar Impact on PP&E Bridge Year	(C) Dollar Impact on PP&E Test Year	(D) Dollar Impact - PP&E Variance Test versus Bridge	(E) [1] Dollar Impact - PP&E Variance Test versus Historic	(F) Directly Attributable? (Y/N)	(G) Reasons why the overhead costs are allowed to be capitalized under MIFRS or an alternate accounting standard given limitations on capitalized overhead
employee benefits				$ -	$ -	Y	Employee wages directly attributed to a capital job are recorded to the applicable capital account. The associated employee benefits are recorded with the wages.
costs of site preparation				$ -	$ -	N	These costs are not currently capitalized by IHDSL.
initial delivery and handling costs				$ -	$ -	N	These costs are not currently capitalized by IHDSL.
costs of testing whether the asset is functioning properly				$ -	$ -	N	These costs are not currently capitalized by IHDSL.
professional fees				$ -	$ -	N	These costs are not currently capitalized by IHDSL.
				$ -	$ -		
costs of opening a new facility				$ -	$ -	N	These costs are not currently capitalized by IHDSL.
costs of introducing a new product or service (including costs of advertising and promotional activities)				$ -	$ -	N	These costs are not currently capitalized by IHDSL.
costs of conducting business in a new location or with a new class of customer (including costs of staff training)				$ -	$ -	N	These costs are not currently capitalized by IHDSL.
administration and other general overhead costs				$ -	$ -	N	These costs are not currently capitalized by IHDSL.
				$ -	$ -		
				$ -	$ -		
				$ -	$ -		
Insert description of additional item(s) and new rows if needed.				$ -	$ -		
Total	$ -	$ -	$ -	$ -	$ -		

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that were capitalized on self-constructed assets under CGAAP but are no longer capitalized under MIFRS or an alternate accounting standard and are included in OM&A.

Nature of the Overhead Costs	(A) [1] Dollar Impact on OM&A Historic Year	(B) Dollar Impact on OM&A Bridge Year	(C) Dollar Impact on OM&A Test Year	(D) Dollar Impact - OM&A Variance Test versus Bridge	(E) [1] Dollar Impact - OM&A Variance Test versus Historic	(F) Directly Attributable? (Y/N)	(G) Reasons why the overhead costs are not allowed to be capitalized under MIFRS or an alternate accounting standard given limitations on capitalized overhead
employee benefits				$ -	$ -	Y	Employee wages directly attributed to a capital job are recorded to the applicable capital account. The associated employee benefits are recorded with the wages.
costs of site preparation				$ -	$ -	N	These costs are not currently capitalized by IHDSL.
initial delivery and handling costs				$ -	$ -	N	These costs are not currently capitalized by IHDSL.
costs of testing whether the asset is functioning properly				$ -	$ -	N	These costs are not currently capitalized by IHDSL.
professional fees				$ -	$ -	N	These costs are not currently capitalized by IHDSL.
costs of opening a new facility				$ -	$ -	N	These costs are not currently capitalized by IHDSL.
costs of introducing a new product or service (including costs of advertising and promotional				$ -	$ -	N	These costs are not currently capitalized by IHDSL.
costs of conducting business in a new location or with a new class of customer (including costs				$ -	$ -	N	These costs are not currently capitalized by IHDSL.
administration and other general overhead costs				$ -	$ -	N	These costs are not currently capitalized by IHDSL.
				$ -	$ -		
				$ -	$ -		
				$ -	$ -		
Insert description of additional item(s) and new rows if needed.				$ -	$ -		
Total	$ -	$ -	$ -	$ -	$ -		

1

PP&E DEFERRAL ACCOUNT AND REQUEST FOR DISPOSITION:

The conversion from Canadian Generally Accepted Accounting Principles (CGAAP) to Modified International Financial Reporting Standards (MIFRS) has resulted in some changes to IHDSL's accounting for Plant Property and Equipment (PP&E).

Table 2.5.2 IFRS-CGAAP Transitional PP&E Amounts below illustrates IHDSL's forecast of the PP&E Deferral account as a result of transition from CGAAP to Modified IFRs, with Modified IFRS incorporating the revised componentized Typical Useful Life as previously stated in Table 2.5.1

IMPACT ON RATE BASE

IFRS-CGAAP Transitional PP&E Amounts
2013 Adopters of IFRS for Financial Reporting Purposes

For applicants that adopt IFRS on January 1, 2013 for financial reporting purposes

Note: this sheet should be filled out if the applicant adopts IFRS for its financial reporting purpose as of January 1, 2013.

	2009 Rebasing Year	2010	2011	2012	2013 Rebasing Year	2014	2015	2016
Reporting Basis	CGAAP	IRM	IRM	IRM	MIFRS	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast			
			$	$	$	$	$	$
PP&E Values under CGAAP								
Opening net PP&E - Note 1				26,060,063				
Additions				6,032,445				
Depreciation (amounts should be negative)				-2,179,090				
Closing net PP&E (1)				29,913,418				
PP&E Values under MIFRS (Starts from 2012, the transition year)								
Opening net PP&E - Note 1				26,060,063				
Additions				6,032,445				
Depreciation (amounts should be negative)				-1,539,226				
Closing net PP&E (2)				30,553,282				
Difference in Closing net PP&E, CGAAP vs. MIFRS (Shown as adjustment to rate base on rebasing)				-639,864				
Account 1575 - IFRS-CGAAP Transitional PP&E Amounts								
Opening balance				0	-639864	-479898	-319932	-159966
Amounts added in the year				-639864				
Sub-total				-639864	-639864	-479898	-319932	-159966
Amount of amortization, included in depreciation expense - Note 2					159966	159966	159966	159966
Closing balance in deferral account				-639864	-479898	-319932	-159966	0

Effect on Revenue Requirement

Amortization of deferred balance as above - Note 2	-159966	**WACC**	6.59%
Return on Rate Base Associated with deferred PP&E balance at WACC - Note 3	- 42,167	**Disposition Period - Note 4**	**4**
Amount included in Revenue Requirement on rebasing	-202133		

Table 2.5.2 above illustrates that through the transition from CGAPP to MIFRS, with MIFRS incorporating the revised componentized Useful Life as previously stated, the calculated difference in closing net PP&E for 2013 Test Year is reduced by -$639,864. As IHDSL transfers from CGAAP to Modified IFRS from January 1, 2013, it is anticipated that this variance will need to recorded and tracked in the Deferral / Variance account which has been identified as a request to the OEB in Exhibit 9.

Based on the *Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment* (EB-2009-0408) dated June 13, 2012, Midland PUC requests this amount be moved to a PPE deferral account for disposition to customers. IHDSL requests a four year disposition period. As directed, this amount will not attract carrying charges but will attract the same level of return as used in determining revenue requirement for this cost of service application as shown on Table 2.5.2.

IAS 16 – Property, Plant and Equipment – Measurement after Recognition.

For subsequent periods following the initial recognition of an asset, IAS 16 permits the choice of using either the Cost Model or the Revaluation Model for valuing PP&E. IHDSL will continue to use the Cost Model to measure PP&E.

Table 2.5.5 – Revenue Deficiency (MIFRS)

Description	2012 Bridge Actual	2013 Test Existing Rates	2013 Test - Required Revenue
Revenue			
Revenue Deficiency			**761,836**
Distribution Revenue	8,503,677	8,100,851	8,100,851
Other Operating Revenue (Net)	422,748	556,948	556,948
Total Revenue	**8,926,425**	**8,657,799**	**9,419,635**
Costs and Expenses			
Administrative & General, Billing & Collecting	2,873,762	3,327,560	3,327,560
Operation & Maintenance	1,760,995	2,137,512	2,137,512
Depreciation & Amortization	1,422,426	1,611,954	1,611,954
Amortization PP&E Adjustment		-159,966	-159,966
Return on PP&E Adjustment		-42,167	-42,167
Property Taxes	12,000	12,500	12,500
Deemed Interest	945,411	1,119,814	1,119,814
Total Costs and Expenses	**7,014,594**	**8,007,207**	**8,007,207**
Utility Income Before Income Taxes	**1,911,831**	**650,592**	**1,412,428**
Income Taxes:			
Corporate Income Taxes	193,927	-92,296	25,788
Total Income Taxes	**193,927**	**-92,296**	**25,788**
Utility Net Income	**1,717,904**	**742,888**	**1,386,640**
Income Tax Expense Calculation:			
Accounting Income	1,911,831	650,592	1,412,428
Tax Adjustments to Accounting Income	-1,044,491	-1,246,052	-1,246,052
Taxable Income	**867,340**	**-595,460**	**166,376**
Income Tax Expense before credits	**193,927**	**-92,296**	**25,788**
Credits	**0**	**0**	**0**
Income Tax Expense	193,927	-92,296	25,788
Tax Rate Refecting Tax Credits	22.36%	15.50%	15.50%
Actual Return on Rate Base:			
Rate Base	31,728,141	38,010,954	38,010,954
Interest Expense	945,411	1,119,814	1,119,814
Net Income	1,717,904	742,888	1,386,640
Total Actual Return on Rate Base	**2,663,315**	**1,862,702**	**2,506,454**
Actual Return on Rate Base	8.39%	4.90%	6.59%
Required Return on Rate Base:			
Rate Base	31,728,141	38,010,954	38,010,954
Return Rates:			
Return on Debt (Weighted)	4.97%	4.91%	4.91%
Return on Equity	8.01%	9.12%	9.12%
Deemed Interest Expense	945,411	1,119,814	1,119,814
Return On Equity	1,016,570	1,386,640	1,386,640
Total Return	**1,961,981**	**2,506,454**	**2,506,454**
Expected Return on Rate Base	6.18%	6.59%	6.59%
Revenue Deficiency After Tax	-701,334	643,752	-0
Revenue Deficiency Before Tax	-903,302	**761,836**	-0

GREEN ENERGY PLAN

IHDSL has submitted a basic Green Energy Plan to the OPA and has provided a copy in Appendix C. The OPA provided a Letter of Comment which has been provided in Appendix D.

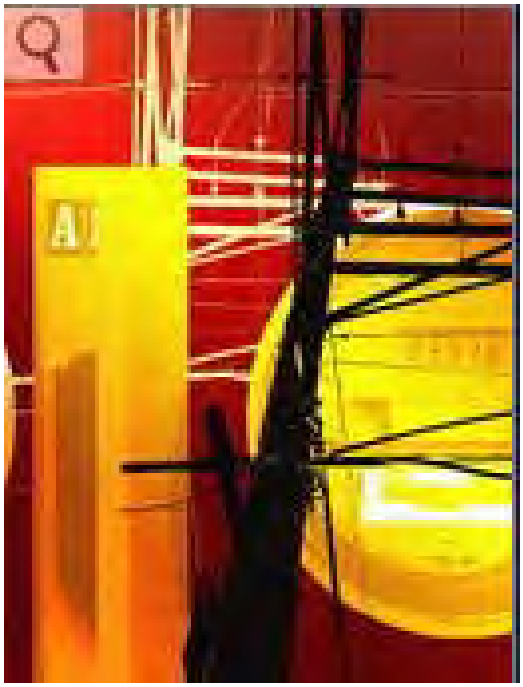
APPENDIX A

IHDSL ASSET MANAGEMENT PLAN

Innisfil Hydro Distribution Systems Limited

Asset Management Plan

2012



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Appendix C, DSC Minimum Maintenance Standards

Background

The Innisfil Hydro Electric Commission was originally formed in January 1991 and in July 1993, the distribution assets were purchased from Ontario Hydro for the service area expansion. 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, defined as the Town of Innisfil as of January 1, 1994.

As of January 1, 2009, 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 hired five “in-house” Linemen in 2010 that perform daily service work requirements. All other associated Line construction projects 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 34 full time staff. The site consists of a Customer Service building, an Engineering and Finance building, a Warehouse building and two old school portables situated on approximately 3.6 acres.

Following the aftermath of the *Oak Ridges Moraine Protection Act 2001*, 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).

Utilizing growth projections from all available data, the following population projections comprises the parameters for growth:

- Innisfil population in 2031 56,000
- New Barrie land population in 2031 39,000
- Big Bay Point development 1,600 units + commercial load

Both population and employment is projected to increase by more than 100% within the next 20 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 be contrary to the Distribution System Code.

AESI Acumen Engineering Solutions was engaged in 2012 to review, provide commentary and make recommendations on the Asset Management Plan. Their report is attached in Appendix 7. Innisfil Hydro staff have implemented all reasonable recommendations from the AESI report into the 2012 Asset Management Plan.

2012 Programs whether O&M or Capital are generally prioritized as follows:

1. Health & Safety
2. Legislative
3. Growth
4. Reliability

*** 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 endeavours to meet the all of the minimum maintenance standards in DSC Appendix C. Reductions in Operations or Maintenance funding may 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.

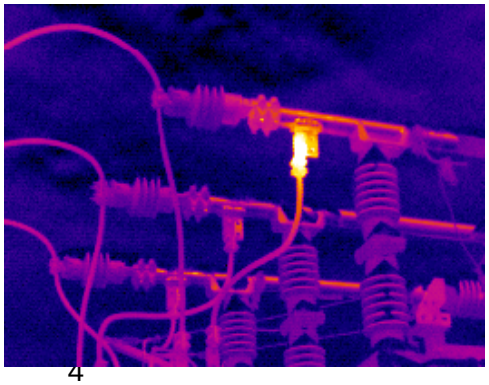
Trees contacting energized lines have the ability to inflict the following:

- 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 within a three year time frame.

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 cost for tree trimming has been budgeted in account 5135.

3.2 Infra-red Scanning



Electrical energy forces 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 pictures (above) shows 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 high voltage assets on a three year cycle as follows:

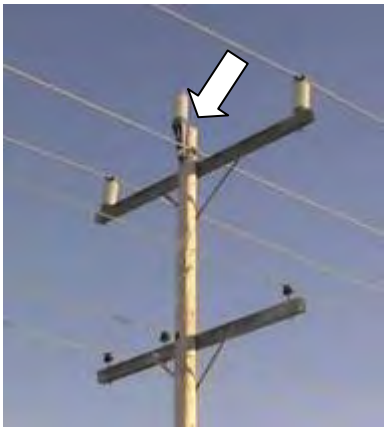
Year 1. All overhead primary voltage 3 phase and single phase lines (44kV, 27.6kV, 8.32kV) including Distribution Stations.

Year 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.

Year 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 cost for infra-red scanning has been budgeted in accounts 5020 & 5045.

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

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 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. Electrical system problems 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 perform a physical inspection at 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 become loose. With weather elements such as wind and ice loading, hardware can eventually 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 $56,000.00 and has not been budgeted for in 2013. 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 has only Operation's staff on standby duty after normal working hours. Engineering and Operation's staff perform line patrol while driving to and from work on a daily basis. The Town is divided into eleven quadrants and staff keep a log of the quadrants and dates that receive line patrol.

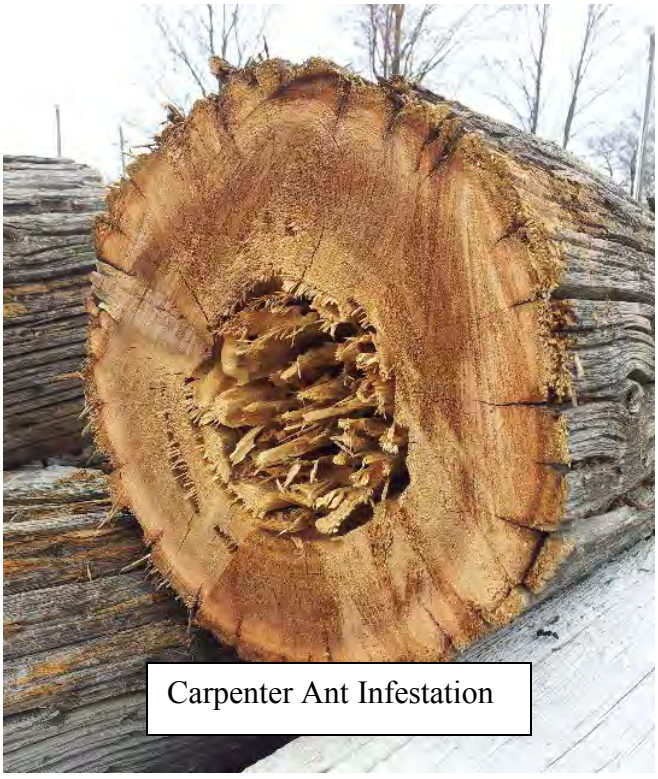
3.4 Poles

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' in length. These pole species involve creosote, chromium copper arsenate or pentachlorophenol treatment to extend the life of the wood. There are no steel or composite poles that are in service in Innisfil. Two concrete poles are in service where feeder 9M6 enters Innisfil. These two concrete poles were installed in 2009 to facilitate installations where guying was not possible.

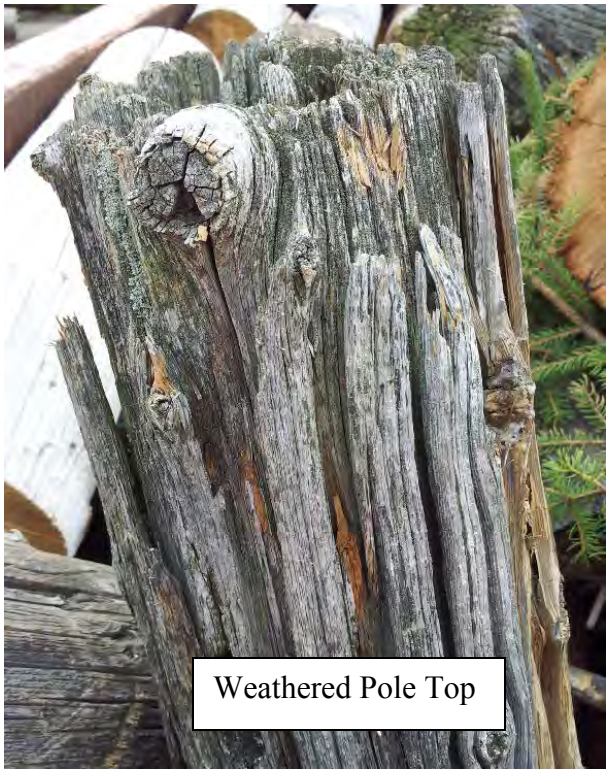
The majority of wood pole deterioration occurs at the pole butt, basically where the pole enters the ground. The amount of pole below the surface is 2 feet plus 10% of the pole height. It is the area flush with the ground that receives the greatest impact of moisture and oxygen that enables the rotting 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 pole replacement is scheduled as required.

While pole testing at grade identifies the need of pole replacements due to ground level pole deterioration. Poles also require replacement as a result of carpenter ant / termite damage and age related weathering above grade. Example of these two pole deficiencies are shown below.



Carpenter Ant Infestation



Weathered Pole Top

Historically, a pole replacement rate of approximately4% has been experienced and is budgeted for within the capital budget. However, an approximate 200-215 of the tested poles per year receive comments back to Innisfil Hydro from the pole testers indicating

deficiencies. Items such as slack or loose guy wires, guy strain insulators pulled apart or broken, guy guards out of position or missing, loose grounding connections and missing nomenclature are a few examples. A maintenance program has not been budgeted before in the past, however with an Annual Pole Maintenance Program, Innisfil Hydro would be able to address the issues raised by our contractor and remediate potential hazards to the public and staff. The annual maintenance cost of **$13,440.00** has been included in the **5120** account in the 2013 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 Geographical Information System (GIS). An increase to a six year pole testing program cycle will increase pole testing costs by over 33%. The typical cost for pole testing utilizing an eight year pole testing program cycle is $30,000.

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 straighten poles that are currently leaning. This issue will always be present with existing poles. 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 visually displeasing to look at, the potential for more dangerous situations may 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 2013.

Pole Replacements are undertaken for the following different reasons:

- Pole decomposition or 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.

Poles are replaced to current ESA requirements. With an approximate 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, capital growth and project requirements:

	2012	2013	2014	2015	2016	2017
Total Count	10,120	10,150	10,180	10,210	10,240	10,270
Total Replacement	215	215	215	215	220	220
Additional	30	30	30	30	30	30

Poles are replaced as required to maximize the health and safety of the public, system reliability and the ability to connect new customers.

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 switches (cut-outs) accept different sizes of fuses, which are used for the protection of lines, equipment or transformers from main feeder amperages. Fused cut-outs are inspected during the infra-red scanning process. Fused cut-outs 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 related fused cut-outs may be replaced as an act of due diligence. Failure to do so will not only decrease reliability and the safety of operational personnel would be compromised.

Load break and air break 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 perform switch maintenance on one quarter of all airbreak and loadbreak switches on an annual basis. The cost to perform three phase switch maintenance has been budgeted in account 5125 which does not include repair parts.

There are numerous in-line switches and mid span openers (MSOs) on the 44kV, 27.6kV and 8.32kV system. These are single phase switches or mid span openers that

can be grouped together on 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 and are replaced as required. Failure to do so will not only decrease reliability, the safety of operational personnel would be compromised. These devices have traditionally received proactive maintenance via the infra red scanning process. An actual physical inspection would require three crew hours to perform in-line switch or MSO maintenance which would require an extra $$12,900 of internal labour annually to implement a cycle program. This new additional amount has been budgeted for in the 5125 account of the 2013 Maintenance Budget.

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;
- Systemic failures involving a particular manufacturer or style.

The following switch addition and replacement schedule has been incorporated to deal with capital requirements:

Disconnect Cutouts Single & Three Phase						
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Total Count	384	399	415	431	447	463
Replacement	30	10	10	10	10	10
Additional	15	16	16	16	16	16
These cutouts include disconnect devices on our distribution infrastructure, but exclude transformer protection fuses.						

Air Break and Load Break Three Phase Switches						
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Total Count	57	65	73	81	89	97
Replacement	2	3	3	3	3	3
Additional *	8	8	8	8	8	8
Includes manual and automatic switches, on both our subtransmission and distribution system. Types include SCADA-Mate's, Alduti-Rupter's, reclosers (used as **switches**), and manual gang switches						
* numbers based on 5 yr plan, pending Green Energy plan approval						

In-Line Switches & MSOs						
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Total Count	336	338	340	342	344	346
Replacement	8	8	8	10	10	10
Additional	2	2	2	2	2	2

3.6 Reclosers

Recloser inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. IHDSL currently has eight (8) three-phase reclosers and 82 single-phase reclosers installed and fully operational on its distribution infrastructure. While all eight (8) three-phase reclosers are radio controlled and serve as circuit breakers inside three (3) of our Distribution Stations (DS), 45 single phase hydraulic reclosers serve as protective devices for station transformers inside the other six (6) of our DS'. The remaining 37 single-phase

hydraulic reclosers are installed on our distribution lines in Innisfil Hydro's system. The list is kept in an EXCEL directory by the Engineering and Operations Clerk. 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 or vacuum chamber 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 reclosers are inspected and rebuilt once ever 4 years. They are also inspected by the infra-red process. Reclosers that are damaged, will be replaced as required. The cost for rebuilding the reclosures is capitalized and the cost for maintaining reclosers is in account 5125.

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. The cost for inspecting voltage regulators is in account 5016. There are no voltage regulators budgeted for replacement in 2013.

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 3071 overhead and pad mounted transformers in its distribution system. The transformer list is kept in the Northstar Billing system. Innisfil Hydro does not have any transformers in confined spaces or below grade.

Transformers are able to transform 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

For Innisfil Hydro to have internal staff or external contractors either climb poles or set-up bucket trucks to inspect transformers up close, it is estimated that the cost of $60 per overhead transformer would be required. This translates into an annual cost increase of $45,000. This has not been budgeted for in 2013.

The annual 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, potential oil leakage or internal/external problems. The following overhead transformer addition and replacement schedule has been incorporated to deal with capital requirements:

Overhead Transformers

	2012	2013	2014	2015	2016	2017
Total Count	2,145	2,156	2,168	2,183	2,203	2,223
Replacement	26	26	27	28	28	28
Additional	11	12	15	20	20	20

The cost for infra-red scanning overhead transformers has been budgeted in account 5020 & 5045.

3.9.1 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. The cost for inspecting capacitors has been budgeted in account 5125. There are no plans to replace any capacitors within the next five year horizon.

Fault Indicators

The installation and use of overhead radio controlled fault indicators has been deployed since 1996. These units send radio signals to the Innisfil Hydro Supervisory Control and Data Acquisition (SCADA) system when fault currents have been detected. They assist in finding a problem section of line and for sectionalizing damaged sections of high voltage lines. Lowering System Average Interruption Duration Index (SAIDI) 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 forty sets of indicators scattered over Innisfil Hydro territory an expected cost of $12,100 would be needed on a yearly basis to make this happen on an annual basis. This new additional amount has been budgeted for in the **5125** account of the 2013 budget.

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 $9,000 of crew labour to complete. This has not been budgeted for in 2013 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 49 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 whereby there are no high voltage connections 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. The cost for infra-red inspecting switching cubicles has been budgeted in account 5020 & 5045. Switch Gears are exposed to a variety of elements which can cause potential public safety hazards, equipment deterioration and operational challenges. In addition to infra-red testing , a more in-depth maintenance program will create an opportunity to lubricate and operate infrequently used load break elbows and switches; repair and/or replace corroded connectors caused by acidic soil conditions and standing water; identify and correct any abnormal soil infiltration; inspect, repair or replace transformer grounding; re-fresh deteriorated nomenclature and identify any damage to the outside of the equipment caused by pedestrian, vehicular and municipal maintenance traffic. An annual maintenance cost of **$49,780.00** under the heading of Underground Transformer and Switch Gear Maintenance has been included in the **5161** account of the 2013 budget.

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 off 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 cost for underground cable locating has been budgeted in accounts 5070, 5075, 5040 & 5045.

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. Pad mounted transformers have their lids opened and are 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. Elbows or cable terminators are nomenclatured to the connecting switch, transformer or switching 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. The cost for infra-red inspecting underground elbows and terminators has been budgeted in account 5020 & 5045. In addition to infra-red testing , a more in-depth maintenance program will create an opportunity to lubricate and operate infrequently used load break elbows and switches; repair and/or replace corroded connectors caused by acidic soil conditions and standing water; identify and correct any abnormal soil infiltration; inspect, repair or replace transformer grounding; re-fresh deteriorated nomenclature and identify any damage to the outside of the equipment caused by pedestrian, vehicular and municipal maintenance traffic. An annual maintenance cost of **$49,780.00** under the heading of Underground Transformer and Switch Gear Maintenance has been included in the **5161** account of the 2013 budget.

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 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. The cost for inspecting underground transformers has been budgeted in the infra-red scanning budget. The cost for infra-red scanning underground transformers has been budgeted in account 5020 & 5045. Underground Transformers are exposed to a variety of elements which can cause potential public safety hazards, equipment deterioration and operational challenges. In addition to infra-red testing , a more in-depth maintenance program will create an opportunity to lubricate and operate infrequently used load break elbows and switches; repair and/or replace corroded connectors caused by acidic soil conditions and standing water; identify and correct any abnormal soil infiltration; inspect, repair or replace transformer grounding; re-fresh deteriorated nomenclature and identify any damage to the outside of the equipment caused by pedestrian, vehicular and municipal maintenance traffic. An annual maintenance cost of **$49,780.00** under the heading of Underground Transformer and Switch Gear Maintenance has been included in the **5161** account of the 2013 budget.

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:

Pad Mounted Transformers

	2012	2013	2014	2015	2016	2017
Total Count	1,030	1,105	1,190	1,275	1,360	1,445
Replacement	8	9	8	9	9	9
Additional	75	85	85	85	85	85

All additional transformers are required to meet load growth and load demand.

4.5 Underground 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. 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 cost for maintaining and inspecting underground primary services has been budgeted in account 5150.

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.

Approximately 30 spans of secondary buss replacement have been budgeted to replace in 2013. 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. Secondary services with a premature failure rate are repaired or replaced as required. The cost for maintaining and inspecting underground secondary services has been budgeted in account 5155.

4.7 Grounding

Lightning from storms 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 had incorporated tens of thousands of dollars put in to arrestor and grounding installations to protect Innisfil Hydro's assets. Older installations like overhead and pad mounted transformers installations, steel cross arm locations and separate dead end arrestor locations that have been existing for many years generally confirm that 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, $18,000 would be needed. This amount has not been budgeted in the 2013 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 $14,500 is required to verify operation maps in the field, which has not been budgeted for in 2013.

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. 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:

- Theft of copper
- Vegetation
- Fencing
- Litter
- Health & Safety
- Station Grounding (visual)
- Condition of SCADA building
- Transformer temperature
- Reclosure operations

There are ten privately owned 44 kV transformer stations connected to Innisfil Hydro's distribution system. Innsifil 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 cost for monthly inspections is budgeted in account 5016. Annual distribution station maintenance includes weed and vegetation control, grass cutting, snow plowing, supervisory control and data acquisition (SCADA) maintenance. The cost for annual maintenance is budgeted in accounts 5114, 5125 and 5012. Due to the evidence of copper theft from substation sites, security at substations has started to be implemented in 2012. Each station security system will have the following features and response protocol.

- Driveway sensor to activate flood light(s) inside the station upon vehicle entering driveway;
- Key activated arm and disarm switch at main entry;
- Magnetic contact on main entry gate;
- Motion sensor(s) inside gated compound (designed to minimize nuisance alarms) which will activate alarm and flood light(s);
- Alarm signals will be communicated via existing SCADA system to on call Manager;
- Securatas Guard Service will provide onsite alarm verification at request of on call Manager prior to Police dispatch;
- On site motion triggered camera will record activity within station.

The contingent cost of copper theft remediation greatly exceeds the scrap copper value that is being taken. Substation security will deter unauthorized entry and therefore improve public safety and system reliability.

5.2 Major Service

On a four year rotation, distribution stations are switched out of service and maintenance is 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 is budgeted in account 5114. 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	1996
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 seven 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. Five

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 Cru Solutions Inc., operated by ERTH Corporation (formerly Erie Thames Power Corporation) 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. Any meter reading problems are investigated immediately by Innisfil Hydro and or Cru Solutions for remedial service. The cost for maintaining wholesale meters is budgeted in account 5175.

6.1 Retail Meters

Innisfil Hydro has over 14,500 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 sample tested. If sample testing shows meter accuracy for residential meters, then sample groups can pass inspection without being re-sealed.

All retail smart meters are read on a daily basis by wireless technology. In 2012, there are approximately 4 residential meters that were not replaced with smart meters due to access restrictions. Staff are diligently working with customers to alleviate the restrictions.

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. The annual cost for maintaining retail meters is budgeted in account 5065.

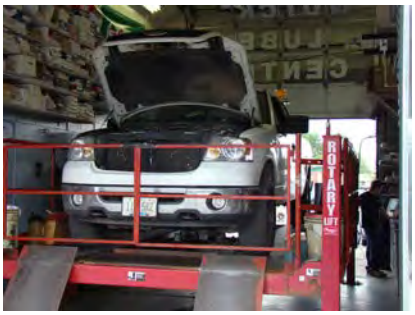
Contract negotiations were completed in 2009 with KTI/Sensus for supply of smart meters, with Olameter for mass deployment of the meters and with Kineiq/Savage Data Systems for Operation Data Storage of the flow of data from the smart meters. The Advanced Metering Infrastructure (AMI) installed is a tower based solution for communicating with deployed smart meters. Two existing towers were chosen, the Town of Innisfil's Churchill Tower and the Town's Big Bay Point Tower on Innisfil Hydro's substation site. Communications equipment was installed at both locations early in 2009, with communications established between the towers in early May. Mass deployment of smart meters commenced mid-September 2009, with substantial completion of March 2010. Innisfil Hydro is now registered with the provincial Meter

Data Management Repository (MDM/R) and have been assigned an identification number.

Time-of-use (TOU) billing to standard supply residential and low volume general service customers commenced on June 1, 2011.

7.0 Vehicle Maintenance

7.1 Service



Innisfil Hydro contracts out some line and all substation maintenance and construction. Innisfil Hydro does not have internal vehicle maintenance staff or equipment and out-sources that function. Innisfil Hydro has fourteen motorized vehicles in its fleet consisting of 1-double bucket line truck, 1-single bucket line truck, 1-RBD, 1-1 ton dump truck, 5 pick-up trucks, 5 Ford Escape Hybrids and 1 forklift. The vehicle replacement plan includes no replacement vehicles in 2012. Most of these vehicles do not meet the weight threshold for Commercial Vehicle Operator Registration (CVOR) except for the one ton dump truck and the three line vehicles. 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 cost for maintaining Innisfil Hydro's fleet is 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 analysis. Maintenance costs will be monitored to determine if they exceed the depreciation of a replacement vehicle. Surplus equipment is sold or disposed of for the greatest benefit to Innisfil Hydro.

YEAR	VEHICLE	TRUCK #	PLATE #
1993	GMC BUCKET TRUCK MODEL WG64	301	359 1YH
2000	GMC PICK-UP WITH DUMP BOX	94	1339XV
2004	CHEVY SILVERADO PICK-UP	84 (Student Truck)	1356NC
2005	DODGE RAM PICK-UP	87 (Julie Jeffels)	XP3 286
2005	DODGE RAM PICK-UP	91 (ON CALL TRUCK)	3765NS
2006	FORD F150	93 (Sheldon Lamoureux)	1185RZ
2008	FORD ESCAPE (HYBRID)	92 (Milan Boldin)	BDBA902
2008	FORD ESCAPE (HYBRID)	85 (Min Gill)	ACMR852
2009	FORD ESCAPE (HYBRID)	88 (Tony Mendicino)	AEME615
2009	FORD ESCAPE (HYBRID)	89 (Pete Stephens)	AEME616
2010	POSI PLUSSINGLE BUCKET MODEL FM2	302	185 9ZB
2010	FORD ESCAPE (HYBRID)	95 (Steve Edwards)	BJWA 824
2010	REEL TRAILER	402	H6112Y
2010	PORTABLE TRAFFIC SIGNALERS (2)	404 (For Both)	NO PLATES
2011	CHEVY SILVERADO HYBRID	96 (Wade Morris)	AA52433
2011	FORD SRW F350 PICK UP	101 (ROB REAL)	3809ZJ
2011	FLOAT TRAILER	403	H6607W
2011	POLE TRAILER	401	H6113Y
2011	FREIGHTLINER RBD	201	554 8ZR

8.0 Property Maintenance

8.1 Sites

Innisfil Hydro owns 10 substation sites and one 3.3 acre head off site. A new 3.5 acre head office site is being purchased in 2012 at the Town's Administrative Campus at 2147 Innisfil Beach Road along with a one acre parcel for a substation in Big Bay Point. 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.

The following list includes all properties owned by Innisfil Hydro and their respective land size and 1999 assessment values.

Innisfil Hydro Land Values

Distribution Stations			
Land Description	Address	Size Acreage	FMV 1999 ($)
Alcona Land	835 Innisfil Beach Rd	0.12	18,000
Brian Wilson DS	1434 Innisfil Beach Rd	2.00	112,000
Big Bay Point DS	709 13th Line	0.91	66,000
Cedar Point DS	733 6th Line	1.84	106,000
Cookstown Land	18 Victoria St.	0.08	17,700
Innisfil DS	2255 Hwy 89	0.28	36,500
Lefroy DS	1495 Kilarney Beach Rd	0.82	62,000
Leonard's Beach DS	2895 25th SR	0.28	35,500
Sandy Cove DS	1104 Lockhart Rd	0.91	66,000
Stroud DS	2135 Lockhart Rd	0.38	45,000
Barrie Land	22 Saunders Rd	3.5	(2012) 465,000
Yard	2033 Commerce Park Dr	1.3	88,000
Eng/Fin	2061 Commerce Park Dr	1.0	(2012) 500,000
CS/Warehouse	2073 Commerce Park Dr	1.0	(2012) 550,000

8.2 Buildings, Head Office

The head office site includes one wood frame building for Customer Service, one wood frame building for Engineering/finance, one wood framed building for the warehouse and two used public school portables (not shown). 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 cost for maintaining the head office is budgeted for in accounts 5085, 5340 and 5620.

The existing facility is not capable of facilitating growth needs. A long range staffing and space needs analysis was undertaken that was correlated with long-term growth projections. A professional architectural firm (McKnight Charron Laurin Inc. Architects) was hired to undertake a study which consisted of the following options:

1. Staying at the same location and making the necessary upgrades and additions to the existing five buildings.
2. Staying at the same location and construct a new building, replacing the five existing buildings.
3. Purchasing a neighbouring commercial property, upgrade and expand the existing buildings.
4. Purchase a green field commercial site and construct a new building.
5. Acquire the vacant Town of Innisfil old administration building and make the necessary upgrades and additions.

The recommendation was for option 5 which provided the best overall value. The site was the only one that was fully serviced from among the five options. It was closer to the centre of Town for response purposes, land was less expensive than the existing site and there is access to public transportation. Architectural renderings were undertaken for the new site with the construction of a single building to engender efficiencies as compared to the existing five buildings. Due to the high cost of renovating the existing building (bricks, roof, HVAC, windows, washrooms, elevator, asbestos, accessibility, etc.), it was deemed prudent to demolish the existing built and construct a new one to LEED standards. It is anticipated that substantial completion of this new building will occur in December 2013.

The building design incorporated some extra space for anticipated future growth needs. This space is designed in a way that it could be leased out to a commercial party until required. The Town of Innisfil's Economic Development Department has indicated that there is a shortage of commercial office space available and that a positive rate of return could be achieved.

Of the three existing lots that Innisfil Hydro currently uses for their head office, two lots are anticipated to be sold to the Town of Innisfil at appraised value for a water reservoir and pumping station. The third lot is used for outdoor storage and will remain as an outdoor storage yard because it contains a transformer station and was designed for a second transformer station on site.

9.0 Equipment Maintenance

9.1 Office Equipment

Office equipment includes desks, chairs, filing cabinets, office partitions etc. Repairs to office furniture occurs as needed and replacements occur generally after 10 years plus. 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 cost of office equipment is budgeted in account 1915. 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, wireless equipment etc. 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 cost of computer hardware is budgeted in account 1920. Surplus equipment is sold or disposed of for the greatest benefit to Innisfil Hydro.

9.3 Line Tools

Innisfil Hydro incorporated in-house Line Staff and Line Tools in 2010 so Line equipment is generally in new condition. Innisfil Hydro also purchases and operates line equipment such as underground cable locating equipment, fault locating equipment, meter analyzers and AVO meters, etc. The equipment is generally kept until it's no longer working or cost beneficial to maintain or replaced with new technologies. The cost of tools is budgeted in accounts 1935, 1940 and 1945.

10.0 Innisfil Beach Road Urbanization

The Town of Innisfil is 'urbanizing' 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 project was initially a four year project with utility relocates starting in 2009. The project has been changed to a two year project with Utility relocates completing in 2011.

The Town of Innisfil has finalized the urbanization design through a By-law. The same By-law requiring utility relocates to be underground. Innisfil Hydro was provided notice 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 the 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 (which is the total project cost without including contributions from the Town of Innisfil) for the relocation of distribution assets on Innisfil Beach Road as follows:

2009 - $1,000,000

2010 - $3,900,000

2011 - $ 464,800

2012 - $ 50,000

11.0 Long Range Load Projections

Long range load projections have been plotted from years 2011 to 2031. The parameters for the load growth model utilizes all known growth plans whereby Innisfil Hydro's customer base will grow to over 35,000 by 2031. Future demand has been estimated at 2 kW / resident which will include loads for commercial requirements such as schools, stores and businesses.

Innisfil Hydro currently has a supply limit of 63 MW from Hydro One and is projected to grow to 124 MW in 2031. This current supply limit will be exceeded so Innisfil Hydro has acquired one new 44kV feeder from Hydro One in late 2009 and another new 44kV feeder is planned for 2017. These new feeders will be able to supply Innisfil until 2020. At that time, four more 44kV feeders or a new Transmission Station will be required until

anticipated build-out in 2031. Innisfil Hydro Staff have met with Hydro One in 2010 to share their long range planning requirements. A report was issued by Hydro One and it is available in Appendix 6. It is expected that dialogue will resume between Innisfil Hydro, Powerstream and Hydro One again in 2014 or 2015 to continue long range supply planning.

Two New 44 kV Feeders into Innisfil Hydro

In the early part of the 2000s, 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 three feeder locations (9M2, 9M3 & 9M6), two of 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 (9M4 & 9M1) are on the same pole line, from 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 other supply feeders from Alliston TS available would have limited that interruption to about 10 minutes. There was no contribution to Hydro One required for one new 44kV feeder. The estimated contribution required to Hydro One in 2008 for the second feeder was $930k and was not undertaken. The project for a single circuit was completed in late 2009.

An approximate four (4) km of single circuit 44 kV sub-transmission was built from the 10 Sideroad of Essa south on Highway 27 and across the 5th Line of Innisfil to the 5 Sideroad. The one new incoming feeder should provide enough capacity for Innisfil until 2017, at that time, the second circuit will be required. Approximately sixty-five (65) poles replaced existing smaller single phase and three phase poles in order to accommodate for the sub-transmission circuits. Within the scope of this project, one metering unit and three (3) 44 kV SCADA load break switches were installed; two (2) switches at the Innisfil Hydro/Hydro One border and a third as a paralleling point within Innisfil Hydro’s system.

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

APPENDIX C - MINIMUM INSPECTION REQUIREMENTS

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

APPENDIX C - MINIMUM INSPECTION REQUIREMENTS

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.

APPENDIX C - MINIMUM INSPECTION REQUIREMENTS

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

8

APPENDIX C - MINIMUM INSPECTION REQUIREMENTS

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						

Notes to Table C-2:

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.

APPENDIX C - MINIMUM INSPECTION REQUIREMENTS

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							

APPENDIX C - MINIMUM INSPECTION REQUIREMENTS

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.

APPENDIX B

IHDSL COST OF POWER

2013 Load Foreacst	**kWh**	**kW**	**2011 %RPP**
Residential	146,562,898		89%
General Service < 50 kW	31,437,455		82%
General Service 50 to 4,999 kW	50,917,130	146,480	5%
Street Lighting	1,505,545	4,400	0%
Sentinel Lighting	104,161	289	89%
Unmetered Scattered Load	592,220		89%
TOTAL	**231,119,409**	**151,169**	

Electricity - Commodity RPP	**2013**	**2013 Loss**			
Class per Load Forecast RPP	**Forecasted**	**Factor**	**2013**		
Residential	129,792,665	1.0714	139,062,222	$0.08069	$11,220,931
General Service < 50 kW	25,898,864	1.0714	27,748,514	$0.08069	$2,239,028
General Service 50 to 4,999 kW	2,313,826	1.0714	2,479,075	$0.08069	$200,037
Street Lighting	0	1.0714	0	$0.08069	$0
Sentinel Lighting	92,456	1.0714	99,059	$0.08069	$7,993
Unmetered Scattered Load	526,982	1.0714	564,618	$0.08069	$45,559
TOTAL	**158,624,793**		**169,953,488**		**$13,713,547**

Electricity - Commodity Non-RPP	**2013**	**2013 Loss**			
Class per Load Forecast	**Forecasted**	**Factor**	**2013**		
Residential	16,770,233	1.0714	17,967,933	$0.07877	$1,415,334
General Service < 50 kW	5,538,590	1.0714	5,934,146	$0.07877	$467,433
General Service 50 to 4,999 kW	48,603,304	1.0714	52,074,464	$0.07877	$4,101,906
Street Lighting	1,505,545	1.0714	1,613,068	$0.07877	$127,061
Sentinel Lighting	11,705	1.0714	12,541	$0.07877	$988
Unmetered Scattered Load	65,238	1.0714	69,897	$0.07877	$5,506
TOTAL	**72,494,616**		**77,672,051**		**$6,118,227**

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**	**2013**		
Residential		kWh	157,030,155	$0.0050	$816,557
General Service < 50 kW		kWh	33,682,661	$0.0046	$158,309
General Service 50 to 4,999 kW		kW	146,480	$1.8708	$282,413
Street Lighting		kW	4,400	$1.4180	$6,398
Sentinel Lighting		kW	289	$1.4109	$423
Unmetered Scattered Load		kWh	634,515	$0.0046	$2,982
TOTAL					**$1,267,081**

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**	**2013**		
Residential		kWh	157,030,155	$0.0040	$643,824
General Service < 50 kW		kWh	33,682,661	$0.0037	$127,994
General Service 50 to 4,999 kW		kW	146,480	$1.4516	$217,156
Street Lighting		kW	4,400	$1.6635	$5,042
Sentinel Lighting		kW	289	$1.1220	$339
Unmetered Scattered Load		kWh	634,515	$0.0037	$2,411
TOTAL					**$996,766**

Wholesale Market Service					
Class per Load Forecast			**2013**		
Residential			157,030,155	$0.0052	$816,557
General Service < 50 kW			33,682,661	$0.0052	$175,150

General Service 50 to 4,999 kW			54,553,539	$0.0052	$283,678
Street Lighting			1,613,068	$0.0052	$8,388
Sentinel Lighting			111,600	$0.0052	$580
Unmetered Scattered Load			634,515	$0.0052	$3,299
TOTAL			**247,625,539**		**$1,287,653**

Rural Rate Assistance					
Class per Load Forecast			**2013**		
Residential			157,030,155	$0.0011	$172,733
General Service < 50 kW			33,682,661	$0.0011	$37,051
General Service 50 to 4,999 kW			54,553,539	$0.0011	$60,009
Street Lighting			1,613,068	$0.0011	$1,774
Sentinel Lighting			111,600	$0.0011	$123
Unmetered Scattered Load			634,515	$0.0011	$698
TOTAL			**247,625,539**		**$272,388**

LV		**Volume**			
Class per Load Forecast		**Metric(w/o losse**	**2013**		
Residential		kWh	146,562,898	$0.0022	$322,438
General Service < 50 kW		kWh	31,437,455	$0.0020	$62,875
General Service 50 to 4,999 kW		kW	146,480	$0.7883	$115,470
Street Lighting		kW	4,400	$1.6331	$7,186
Sentinel Lighting		kW	289	$0.6065	$176
Unmetered Scattered Load		kWh	592,220	$0.0020	$1,184
TOTAL			**178,743,742**		**$509,329**

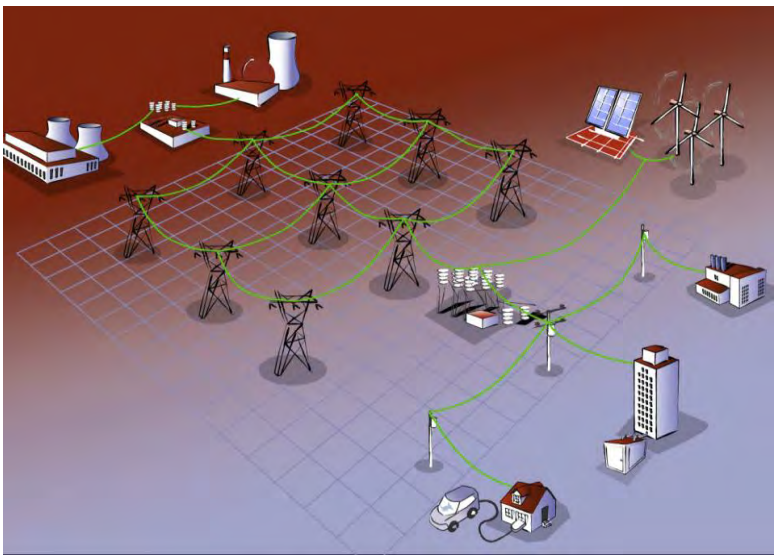
Summary	**2013**
4705-Power Purchased	$19,831,774
SME	$73,097
4708-Charges-WMS	$1,287,653
4714-Charges-NW	$1,267,081
4716-Charges-CN	$996,766
4730-Rural Rate Assistance	$272,388
4750-Low Voltage	$509,329
TOTAL	**24,238,088**

APPENDIX C

GREEN ENERGY PLAN

Innisfil Hydro Distribution Systems Limited

Green Energy Act Plan (Basic Plan)



July 23, 2012

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1. Introduction

This document outlines the Green Energy Act Plan for Innisfil Hydro Distribution Systems Limited (IHDSL).

At this time IHDSL is filing the basic Green Energy Act (GEA) Plan, as directed by the OEB document EB-2009-0397 Distribution System Plans – Filing Under Deemed Conditions of License revised May 17, 2012. The basic GEA Plan provides information to the Board and interested stakeholders regarding the readiness of IHDSL's system to accommodate the connection of renewable generation and the expansion or reinforcement necessary to accommodate renewable generation. In addition this report provides information with respect to the general condition of the distribution system.

2. Current Assessment of Distribution System

2.1. Distribution System Overview:

Innisfil Hydro Distribution Systems Limited owns, operates, and maintains a distribution system currently serving approximately 15,000 customers within an area of about 300 square kilometers. The service territory encompasses all of the Town of Innisfil, which includes the communities of South Barrie, Stroud, Alcona, Lefroy, Churchhill, Cookstown, Gilford, Sandy Cove, and Big Bay Point. A majority of our customers are located in the above noted urban centers'. We also serve a smaller percentage of customers who are farmers.

IHDSL's industrial customer base is minimal in comparison to residential customers. We have had a significant growth in the area in the past 10 years and expect this trend to continue into the next decade. We predict our customer base to double in the next 15 years.

We currently operate our subtransmission system at 44 kV and our three-phase distribution system at 27,600 and 8,320 volts. We own, operate and maintain nine (9) distribution substations, jointly own, operate, and maintain four (4) private substations, and inspect and maintain seven (7) other customer owned substations.

The average age of our substations is 33 years; a majority of them were installed and commissioned in the 1970's. We own, operate, and maintain four (4) subtransmission feeders, 27 distribution feeders, approximately 750 km of both overhead and underground conductors, and 3,085 distribution transformers.

In the past six (6) years we have designed, installed, and commissioned one (1) distribution substation. We have systematically invested significant capital in upgrading our Distribution Automation (DA), and Supervisory Control and Data Acquisition (SCADA) systems, our IT infrastructure, deploying newer Reclosers and Scada-Mate® switches, SCADA software for use by System Operators, and backend enterprise systems to support the need for better data management and system integration.

In 2011 we replaced all hydraulic reclosers at the Leonards Beach Distribution Station (DS) with the newer vacuum reclosers with microprocessor controls[1]. Our goal is to upgrade the remaining hydraulic reclosers in our distribution system in the near future with the newer vacuum type with advanced electronic controls, as part of our Smart Grid initiative. This initiative will help improve reliability by reducing outage duration while assisting our efforts to track and mitigate momentary interruptions.

We recently installed approximately 15,000 residential and commercial electric "smart" meters, completing our Advanced Metering Infrastructure (AMI) program and implementing TOU billing for all eligible customers by June 2011. We are currently developing internal processes to better utilize smart meter data to further improve our customer experience. Albeit, our AMI meters do not have true 2-way communication, thereby limiting our customers' ability to participate in the CDM Demand Response Programs pertaining to water heaters, pool pumps, peaksaver, etc. We are in the process of reviewing the cost implications for upgrading (1) AMI meters with 2-way communication capability, and (2) our current IT infrastructure (both capital and O&M) to accommodate the system requirements for the implementation of Demand Response programs.

We have worked with our neighbours, Hydro One and Power Stream, on our 15 year future growth plan to establish the possibility of building a 230 kV TS to better serve the growing demand for power.

We are committed to continuing our infrastructure renewal program **to improve customer participation** in reducing energy consumption**, improve system reliability** by reducing outages and outage duration**, improve operational efficiency** by deploying distribution automation and Smart SCADA technology, **improve security and safety** by reducing the vulnerability of the grid to unexpected hazards and promoting a safer system for both workers and the general public, and **promote environmental quality** by allowing customers to purchase cleaner, lower-carbon-emitting generation, and promote a more even deployment of renewable energy sources.

[1] G&W Viper Reclosers with SEL 351R controls

Table 1 - **Circuit length (in meters)**

System Voltage	44 kV	27.6 kV	8.32 kV	TOTAL
Overhead	125,900	98,700	382,800	607,400
Underground	700	66,100	74,400	141,200
<uncategorized>	300	3,600	1,700	5,600
Total	126,900	168,400	458,900	754,200

Table 2 - **Distribution Transformer Count**

System Voltage	44 kV	27.6 kV	8.32 kV	TOTAL
Overhead	0	444	1,649	2,093
Padmount	0	477	509	992
Total	0	921	2,158	3,085

2.2. Embedded Distribution System

Subtransmission: IHDSL is embedded into Hydro One Networks Inc.'s (HONI) subtransmission system. We currently own, operate, and maintain four (4) subtransmission feeders[2] from our boarder connection point, all of which have been identified by HONI to have available capacity to connect FIT or micro-FIT generators (as of July 17, 2012). A new subtransmission feeder[3] has been planned for 2017 to accommodate future load growth.

Distribution: Among our 27 distribution feeders 26 feeders still have available capacity to connect generators, while four other feeders are nearing their capacity for micro-FIT connection. As of this report date, 24 feeders have a total of 1.2 MW of solar generation already connected or slated to be connected.

[2] Alliston TS 9M1, 9M2, 9M4, and Barrie TS 13M3
[3] 9M6 from Alliston TS

2.3. Municipal Substations

IHDSL has nine (9) substations serving the community. The total design capacity is 58 MVA providing a margin of safety over the peak system load of 15%[4]. The subtransmission system (44 kV) allows for transfer of loads between stations as required.

[4] Based on a 70% load factor on our DS transformers

Table 3 - **Feeder Data:**

SUBSTATION	LOCATION	SIZE	OWNER	FEEDER #	Volt	Vintage
BIG BAY POINT DS	709 13th Line	5,000 KVA	Innisfil Hydro	F1 & F2	44/8.32 KV	1971
BOB DEUGO DS	2033 Commerce Park Drive	10,000 KVA	Innisfil Hydro	F1 & F2	44/27.6 kV	2006
BRIAN WILSON DS	1434 Innisfil Beach Road	20,000 KVA	Innisfil Hydro	F1, F2, F3 & F4	44/27.6 kV	1991 (T1) 1991 (T2)
CEDAR POINT DS	733 6th Line	5,000 KVA	Innisfil Hydro	F1 & F2	44/8.32 kV	1976
INNISFIL DS	2255 Highway #89	5,000 KVA	Innisfil Hydro	F1, F2 & F3	44/8.32 kV	1978
LEFROY DS	1495 Killarney Beach Road	5,000 KVA	Innisfil Hydro	F1, F2 & F3	44/8.32 kV	1970
LEONARDS BEACH DS	2895 25th Sideroad	5,000 KVA	Innisfil Hydro	F1 & F2	44/8.32 kV	1974
SANDY COVE DS	1104 Lockhart Road	5,000 KVA	Innisfil Hydro	F1 & F3	44/8.32 kV	1975
STROUD DS	2135 Lockhart Road	5,000 KVA	Innisfil Hydro	F1, F2 & F3	44/8.32 kV	1969
COOKSTOWN WEST DS	Victoria St. Cookstown, West of Cty.Rd. 27	7,000 KVA	Hydro One	F2 & F4	44/8.32 kV	--
THORNTON DS	Innisfil Beach Rd. East of Cty.Rd. 27	5,000 KVA	Hydro One	F1 & F2	44/8.32 kV	--

Note: All transformers are connected as Delta-Primary and Wye-Secondary.

2.4. Station Metering and Monitoring

We have installed and commissioned station monitoring equipment and systems on all nine (9) of our substations, while only three[5] (3) have smart SCADA equipment installed and functional, as noted in the table below. Our intent is to add remote sensing and switching capability with Smart Grid Self-healing properties to the remaining six (6) stations. *We currently do not monitor private substations.*

Table 4 – **Smart SCADA Status of IHDSL DS**

STATION	Station Monitoring Capability	Smart SCADA Status
BIG BAY POINT DS	YES	NEEDS UPGRADE
BOB DEUGO DS	YES	Fully Functional
BRIAN WILSON DS	YES	Fully Functional
CEDAR POINT DS	YES	NEEDS UPGRADE
INNISFIL DS	YES	NEEDS UPGRADE
LEFROY DS	YES	NEEDS UPGRADE
LEONARDS BEACH DS	YES	Fully Functional
SANDY COVE DS	YES	NEEDS UPGRADE
STROUD DS	YES	NEEDS UPGRADE

We are currently engaging with other public utilities to share costs.

- Communication infrastructure
    - We currently use an unlicensed frequency band for our SCADA system and have experienced significant signal interference. In an effort to improve signal quality we are working on replacing/upgrading all our communication equipment to use the dedicated utility frequency band that was recently released for LDC usage by Industry Canada. We are planning on completing this upgrade before the end of next year, which will require significant investment in capital and O&M.
    - As part of the SCADA upgrade we intend to replace the older vintage OPTOMUX protocol equipment with newer technology devices, while quality testing our existing DNP3 communication equipment to ensure long term reliable operation.

[5] Namely Bob Deugo, Brian Wilson, and Leonards Beach DS

- This new technology gives us the capability to monitor and control DG units, which in turn allows us the opportunity to consider a higher number of DG connection requests.
- The installation of the new SCADA system will improve our ability to obtain real time voltage readings at various locations of our single and three phase distribution system, which in turn will enable us to better determine circuit response to load and other operating conditions. This will further assist us in the evaluation of DG connection requests.
- For the implementation of the above two projects it will be necessary for us to expand our technical support team by adding **ONE new position** in 2013. The added cost is reflected in Table 9.

2.5. Feeder Capacities to Connect Generation

At IHDSL we follow the guidelines stipulated by Hydro One in their document: Distributed Generation Technical Interconnection Requirements – Interconnections at Voltages 50kV and below; DT-10-015 Rev 2, June 2011. In this section Hydro One stipulates the acceptable generation limits for three-phase and single phase generators for DG facilities interconnected to HONI Distribution feeders. We use the same guidelines for our system. In addition, we use other industry recognized standards and procedures in determining connectability of DG's to our system; including IEEE 1547, which is the "Standard for Interconnecting Distributed Resources With Electric Power System", and calculations based on feeder specific load calculations. We have a design threshold to limit connected DG power to 50% of our calculated average minimum load of each feeder, which is determined to be 15% of the average maximum load on the respective feeder.

An internal tracking worksheet is used to log all interconnection points and their capacities. Using this log we are able to determine the total connected generation on each feeder, and decide if any additional generators can be connected.

The following table shows the connected or pending Distributed Generators (DG) on each feeder and the remaining capacities. Ratings are given in kilo-Watts.

Table 5 – **IHDSL Feeder Capacity Status for DG Connectivity - Distribution**

Distribution System

Distribution: Among our 27 distribution feeders 26 feeders still have available capacity to connect generators, while four feeders are nearing their capacity for micro-FIT connection.

Station	Feeder	Max DG Capacity	Connected or Pending	Remaining Capacity
Innisfil	F3	96	118	NONE
Innisfil	F1	122	40	82
Innisfil	F2	105	20	85
Big Bay Point	F1	124	3	121
Big Bay Point	F2	115	20	95
Bob Deugo	F1	47	10	37
Bob Deugo	F2	54	20	34
Brian Wilson	F1	91	71	20
Brian Wilson	F2	75	70	5
Brian Wilson	F3	168	82	86
Brian Wilson	F4	TBD	0	TBD
Cedar Point	F1	146	15	131
Cedar Point	F2	202	5	197
Cookstown-West	F2	82	13	69
Cookstown-West	F4	102	10	92
Leonards Beach	F1	104	7	97
Leonards Beach	F3	144	15	129
Lefroy	F1	152	10	142
Lefroy	F2	93	20	73
Lefroy	F3	60	20	40
Sandy Cove	F1	92	0	92
Sandy Cove	F3	69	0	69
Stroud	F1	86	25	61
Stroud	F2	16	10	6
Stroud	F3	132	44	88
Thornton	F1	67	50	17
Thornton	F2	33	30	3

Orange highlight: No more capacity for DG connection
Yellow highlight: Nearing capacity for DG connection

Subtransmission System

As noted earlier in this report IHDSL is embedded into Hydro One Networks Inc.'s (HONI) subtransmission system, and we currently own, operate, and maintain four (4) subtransmission feeders from our boarder connection point, all of which have been identified by HONI to have available capacity to connect FIT or micro-FIT generators as noted below.

Table 6 **- IHDSL Feeder Capacity Status for DG Connectivity - Subtransmission**

Feeder	TS	Voltage	Rating	Available DG Capacity
9M1	Alliston	44 kV	600 amps	30.0MW
9M2	Alliston	44 kV	600 amps	30.0MW
9M4	Alliston	44 kV	600 amps	29.80MW
13M3	Barrie	44 kV	600 amps	29.75MW

Note: Above capacity data was calculated on 17-July-2012 using Hydro One's Capacity Evaluation Tool. Please see Appendix section for screen shots of calculation.

2.6. Challenges related to our distribution system:

Currently we are facing capacity limitations on five (5) distribution feeders. One feeder has already reached its maximum capacity for DG connectivity while four (4) other feeders are nearing their maximum capacity. Over the next two to three years we are anticipating DG connection requests to amount to 2 - 3 MW in total. It is very likely that our aging infrastructure would need to be upgraded to accommodate the anticipated DG connection applications. However, an accurate estimate of the extent of system upgrades and associated costs are better determined after the specific feeders on which these DG units will be connected are identified. In the interim, as we continue to expand our in-house technical capabilities to conduct substation and feeder based studies, and implement communication and SCADA system upgrades, it is imperative that we have the opportunity to employ an **additional technician** starting in 2013 to adequately support these efforts.

One of the other challenges we face in our distribution system pertains to the sharing of the distribution infrastructure with other LDC's. We currently have four (4) feeders that are based out of two separate HONI owned stations, namely Thornton DS and Cookstown DS. Since two separate LDC's are operating out of the same substation it poses logistical problems. These arrangements pose unique challenges when working on micro-FIT and FIT projects.

Table 7 - **HONI owned DS with IHDSL feeders**

Station Name	Bus Name	Feeder Name	Voltage (kV)	Thermal Capacity (MW)	Upstream TS	Upstream TS Feeder
Cookstown West DS	Total	F1, F2*, F3, F4*	8.32	4.8	Everett TS	M6
Thornton DS	Total	F1*, F2*, F3	8.32	3.3	Alliston TS	M4

* Feeders owned by IHDSL

Long Term Load Transfer (LTLT) Customers

IHDSL supplies power to 95 Hydro One LTLT customers via three IHDSL's feeders[6]. These feeders supply power to the following LTLT customers: 61 metered customers, 33 flat rate customers, and 1 micro-FIT customer; these are HONI

[6] Cookstown F4, and Thornton F1 and F2

customers who are supplied power through our distribution infrastructure. We do not have any IHDSL customers who are fed off HONI distribution infrastructure.

Under this arrangement of shared ownership where the station is owned by HONI, the feeder is owned by IHDSL, and the distribution transformer and meter are owned by HONI, we have constant challenges in working through FIT and micro-FIT applications when approached by HONI customers. These customers come under the care of HONI yet for DG connectivity all infrastructure related calculations and upgrade works need to be done by IHDSL.

We have reviewed and analyzed various alternative solutions but all such options were deemed to be cost prohibitive.

We are cognisant of the June 30, 2014 deadline for eliminating LTLT arrangements which will help LDC's with dealing with distributed generation requests; however, logistical challenges for the remaining two years need to be addressed. As of the report date, IHDSL has 33 HONI owned transformers[7] on the distribution system.

2.7. Identification of Expenditures

As noted in table 5, several of our feeders do not have additional capacity for DG connectivity, and therefore, if we are to continue to offer our customers the opportunity to connect their renewable power generators to our grid we would need to implement a variety of infrastructure upgrade projects to accommodate their generators. As of this report date, a detailed engineering analysis and estimate is currently being developed.

As part of our infrastructure renewal plan we have proposed the following expenditure for the next five years:

Note: costs highlighted in green are in addition to IHDSL's forecasted Capital and OM&A budgets.

[7] 12 are located on the Cookstown F4 Feeder, 3 located on the Thornton F1 Feeder, and 18 located on the Thornton F2 Feeder.

Table 8 - **Substation & Distribution System Upgrade:**

Description	Budget $				
	2013	2014	2015	2016	2017
Recloser Automation, Replacement, & Line Recloser Maintenance (4 yr cycle)	$ 223,300[a]	$ 232,000[a]	$ 248,500[a]	$ 265,900[b]	$ 253,200[b]
44kV SCADA Controlled Load Interrupting Gang Switches	$ 160,100	$ 166,300	$ 178,200	$ 190,600	$ 203,000
27.6kV SCADA Controlled Load Interrupting Gang Switches	$ 253,200	$ 263,100	$ 281,700	$ 301,500	$ 321,000
Implementation of Automated Sectionalization and Restoration (ASR)[8]	$ 250,000	$ 250,000	$ 250,000	$ 250,000	$ 250,000
Fault Current Indicators	$ 38,400	$ 39,900	$ 42,700	$ 45,700	$ 48,700
Total	$1,175,000	$1,201,300	$1,251,100	$1,303,700	$1,325,900

[a:] Substation Recloser upgrade; [b] : Line Recloser Upgrade

Table 9 **- Investment in Personnel and Enterprise Architecture:**

Description	2012	2013	2014	2015	2016	2017
Smart Grid/Green Energy Engineer	75,000	100,000	103,000	106,100	109,270	112,550
- Support Tech.[c]	0	75,000	77,250	79,600	82,000	84,460
New SCADA System	200,000	250,000 [c]	0	0	0	0
Software Upkeep [c]	25,000	10,000	10,300	10,600	10,900	11,500
Radio Hardware Installation & Commissioning [c]	0	200,000	0	0	0	0

[C] Not included in the current 5 year plan

[8] Not included in the current 5 year plan. The implementation of the ASR scheme will give us the option to automatically sectionalize faulted segments of a feeder and restore power to as many customers as possible through the intelligent and strategic switching of circuit ties.

GEA Budget

Costs to support the Substation & Distribution System Upgrade, Investment in Enterprise Architecture and personnel to support the technology and implementation is broken down by category and year in the following table,

	2013 ($000)	2014 ($000)	2015 ($000)	2016 ($000)	2017 ($000)	Total ($000)
Capital	710	260	261	261	262	1754
OM&A	75	77	80	82	84	398
Total	785	337	341	343	346	2152

Further details of the GEA Budget, strategy and proposed riders will be addressed within IHDSL's COS Application EB-2012-0139.

2.8. Unique Challenges

We have seen substantial interest from farmers in our service territory for both microFIT and FIT solar projects; however, with the visibility of the generators there has been a steady transition of residential roof mount solar projects. Given the older infrastructure on parts of our service territory we see a need for upgrading our infrastructure over the next few years.

3. Planned Development of the Distribution Systems to Accommodate Generation Connections

3.1 Existing and Pending Renewable Generation Projects:

Since the rollout of the MicroFIT and FIT programs, IHDSL has received a large number of requests for solar panel installations on its grid. To date we have approximately 135 FiT/MicroFiT projects that have either been approved or being evaluated, while several other requests are being put on hold due to capacity. Although received projects slowed down in late 2011 due to the 2 Year FIT Review, IHDSL is again experiencing an increase in DG connectivity requests. IHDSL fully expects the requests to maintain in the foreseeable future. Therefore, need to plan infrastructure upgrade projects including substation and distribution automation, to benefit DG connections, and accommodate additional generation.

MicroFIT Summary

Installed Projects by Year

YEAR	2010	2011	2012	2013	2014	2015	2016
Forecast	5	15	20	25	30	30	30
Actual	10	29	10 *				

*as of July 23, 2012

Breakdown of MicroFIT Applications (as of July 23, 2012)

Total Connected	49
Pending Connection	32
Pending LDC OTC	15
Application Terminated	27
Contract Transferred	8
Total Applications	131
Total Capacity	1173.52 kW

FIT Summary

Installed Projects by Year

YEAR	2010	2011	2012	2013	2014	2015	2016
Forecast	1	2	3	3	3	3	3
Actual	0	1	0*				

*as of July 23, 2012

Breakdown of FIT Applications (as of July 23, 2012)

Total Connected	1
In CIA Process	1
Pending CIA Process	2
Total Applications	4
Total Capacity	990 kW

3.2 Infrastructure Projects and Activities to Accommodate Renewable Generation

Our priority would be to upgrade feeders that have reached maximum capacity for DG connectivity. At the top of the list is the upgrading of the backbone of our Innisfil F3 feeder, on which we have a backlog of DG applications, and that is long past its depreciation. We have observed widespread deterioration of the assets of this feeder and have deemed it necessary to completely rebuild about 5 km of infrastructure at an approximate cost of $600k-$700k, subject to feeder load conditions.

In addition, the upgrade projects that are part of our Smart Grid initiatives are expected to indirectly benefit renewable generation.

3.3 Costs to be Recovered

For the above noted project we anticipate our material to labor cost ratio to be approximately 40/60.

Additional cost recovery schedules will be provided upon request.

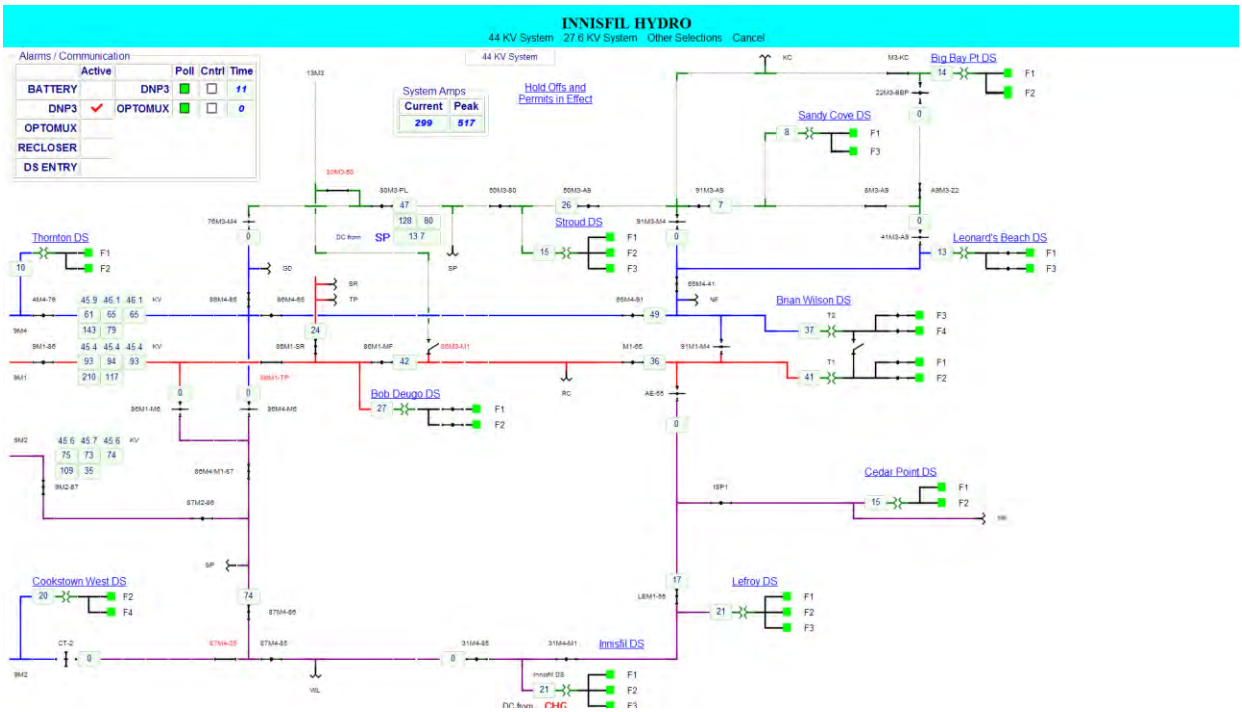
4. Smart Grid Development

One of the major initiatives IHDSL had worked on under the Smart Grid umbrella is the AMI project. As part of this project we installed and commissioned approximately 15,000 meters. In addition we have invested time and resources for the upkeep of our SCADA system, replacing, upgrading, and/or maintaining substation Remote Terminal Units (RTU's), SCADA switches, and Reclosers.

We are continuing to pursue projects to further modernize and automate our infrastructure, while looking for ways to provide our customers more choices to conserve energy.

Our grid modernization plan includes:

- Replacing our old SCADA system with modern state of the art system. Our current 8,320 volt distribution system is not tied into our current SCADA system, while our 27.6 kV system has limited line visibility.
    - The new SCADA system will help improve visibility on both these systems and will help with quicker outage restoration, improving our SAIDI and CAIDI metrics.
    - Our SCADA system, as currently configured, is remotely operable through control terminals in our operation centres as well as through secure mobile devices. The new SCADA system we are proposing to install will also be configured with remote accessibility, allowing greater functionality.



- Introducing enterprise-wide engineering, accounting, work management, and customer information systems that seamlessly integrate to provide improved efficiency, and better business intelligence that would lead to better business decisions for our customers and us
- Replacing/upgrading our reclosers and switches for the implementation of "Distribution Automation".
- Installing advanced Fault Current Indicators with communication capability will reduce the time taken to locate our faults and help reduce outage restoration times and overall reliability.

Some of the Benefits of Distributed Generation:

- Power quality and reliability- For sensitive equipment (computer equipment, manufacturing process equipment) or in the event where a power outage could seriously impact a business, DG can be used to improve power quality and reliability.

- Security - A DG system can provide added security by maintaining power to critical operating areas which would otherwise be affected by utility power outages.

- Environment - Many DG installations reduce total emissions levels by using energy resources more efficiently, replacing heating and water heating fossil fuel combustion emissions and in some cases displacing more damaging central plant emissions.

- Other – DG's further help with avoiding future expansions of transmission and distribution networks in their respective areas.

How Investment in Smart Grid Technology may help Distributed Generation Initiatives:

- The implementation of Substation and Distribution Automation is expected to reduce the number of sustained outages and thereby decreasing the downtime of DG units that would have otherwise been dropped from the grid.

- The ability to track momentary outages by installing advanced microprocessor controlled automatic interrupting devices will provide intelligent data on momentary outages that would help LDC's implement proactive solutions to eliminate sustained outages.

- Our new communication infrastructure will enable real time monitoring of our subtransmission and distribution system, further helping operator assisted restoration efforts, and thereby reducing downtime.

- The installation of smart meters will enable us to harvest accurate load data which in turn will help us optimize DG connection capacity on our feeders.

5. Summary

The GEA Plan has been prepared to illustrate the ability to accommodate renewable generation. Through the plan the existing capacity has been outlined as well as requirements for future investments.

In order for IHDSL to continue to accommodate DG connection requests, given our current system limitations, we would need to follow through with the various infrastructure improvement projects as outlined above.

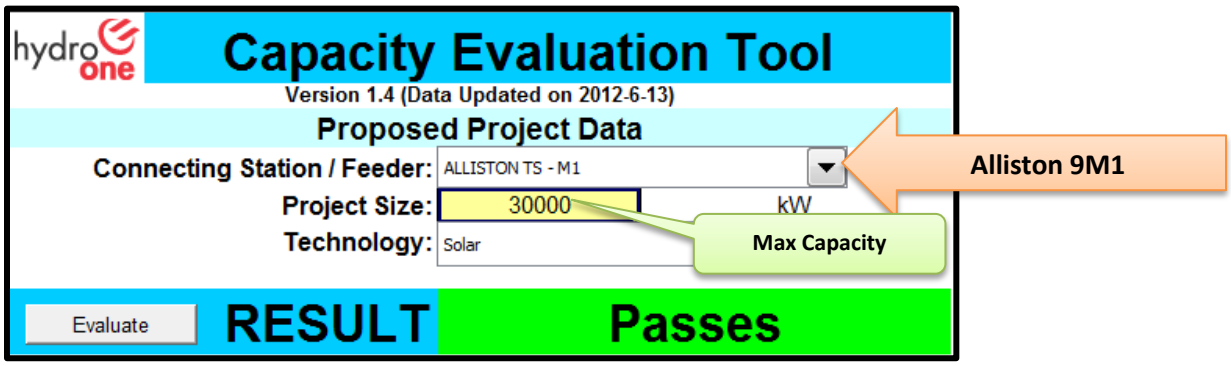
Should additional supporting documentation be required IHDSL will be glad to provide such as required.

END OF REPORT

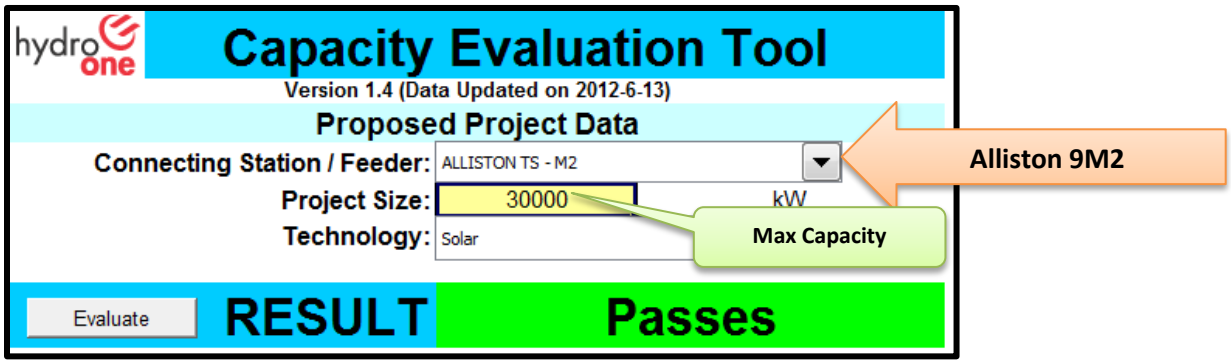
Appendix

Service Territory

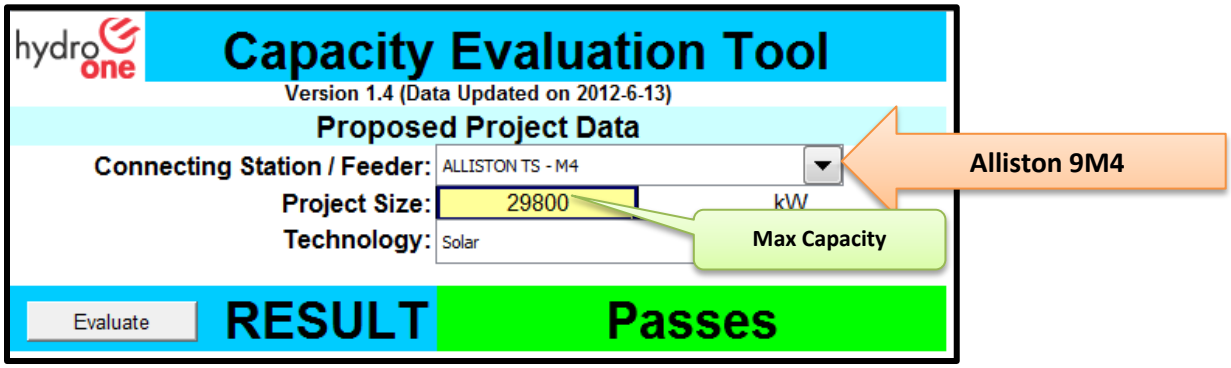
DG connectivity capacity at TS



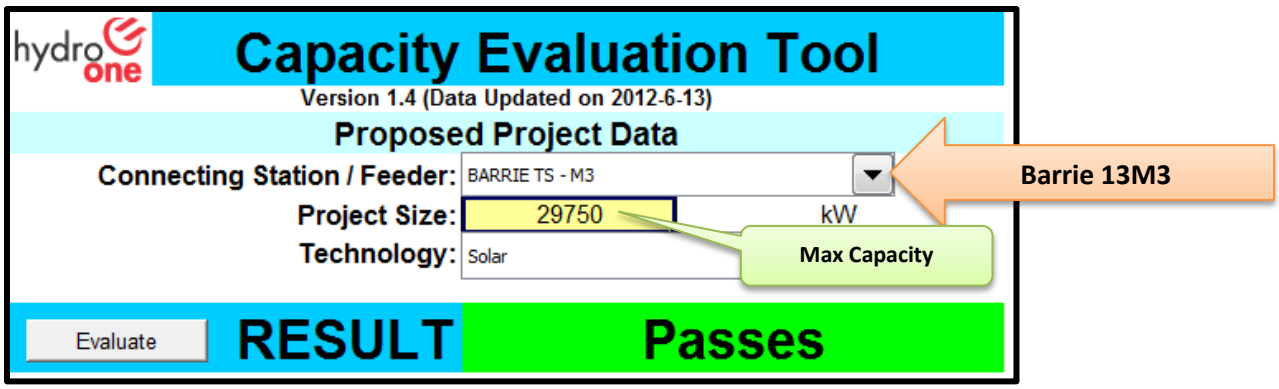
Above test FAILED at 31MW



Above test FAILED at 31MW



Above test FAIELD at 29.9MW



Above test FAILED at 29.8MW

Note: These scenarios were tested on 17-July-2012 using Hydro One's Capacity Evaluation Tool.

APPENDIX D

OPA LETTER OF COMMENT

OPA Letter of Comment:

Innisfil Hydro Distribution Systems Limited

Basic Green Energy Act Plan

August 20, 2012

ONTARIO POWER AUTHORITY

Introduction

On March 25, 2010, The Ontario Energy Board ("the OEB") issued its Filing Requirements for Distribution System Plans. As a condition of Licence, Ontario Distributors are required to file a Green Energy Act Plan as part of their cost of service application.

The Filing Requirements distinguish between Basic and Detailed Green Energy Act Plans ("Plan" or "GEA Plan") and outline the specific information and level of detail which must be provided for each type of Plan. Recognizing the importance of coordinated planning in achieving the goals of the *Green Energy and Green Economy Act, 2009* (the "GEA"), distributors must consult with embedded and host distributors, upstream transmitters and the OPA in preparing their Plans. For both Basic and Detailed Plans, distributors are required to submit as part of the Plan, a letter of comment from the OPA.

The OPA will review distributors' Basic Plans to ensure consistency with regard to FIT and microFIT applications received, as well as with integrated Plans for the region or the system as a whole.

Innisfil Hydro Distribution Systems Limited - Basic Green Energy Act Plan

The OPA has reviewed the Basic GEA Plan from Innisfil Hydro Distribution Systems Limited dated July 23rd, 2012, and has provided its comments below.

OPA FIT/microFIT Applications Received

Innisfil Hydro's GEA Plan indicates they have received applications for 131 microFIT and 4 Capacity Allocation Except ("CAE") projects within their service territory. Of these, 49 microFIT and 1 CAE projects have been connected. No Capacity Allocation Required (CAR) applications have been received. This information is shown in section 3.1 *Existing and Pending Renewable Generation Projects* of the Plan.

According to OPA's information, as of August 8th, 2012, 130 microFIT, and 4 Capacity Allocation Exempt ("CAE") applications have been received in Innisfil Hydro's service territory, representing 1.16 MW and 0.99 MW of capacity, respectively. Of these, 53 microFIT and 1 CAE projects are currently connected.

Upstream Transmission Constraints

According to the information provided in Innisfil Hydro's GEA Plan, Innisfil Hydro's distribution system is supplied from feeders originating from Alliston TS and Barrie TS. The OPA confirms that there are no currently known upstream transmission constraints at Alliston, Barrie TS, or at other nearby transmission supply points.

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info@powerauthority.on.ca www.powerauthority.on.ca

Further details on capacity at the above mentioned stations may be found in the updated Transmission Availability Table for Small FIT 2012 available on the OPA's FIT website as follows: http://fit.powerauthority.on.ca/sites/default/files/TAT%20Table%20Final%20-%20April%205%20for%20posting.pdf

Economic Connection Test

The OPA received a directive dated April 5, 2012 from the Minister of Energy with respect to the Feed-in Tariff Program Review. The directive states that "[g]iven the transmission projects planned through the Long Term Energy Plan and changes to the FIT Program, the OPA shall not run the Economic Connection Test ". A link to the full directive is provided on the OPA's website: http://www.powerauthority.on.ca/sites/default/files/page/FIT-ReviewApril-2012.pdf

Opportunities for Integrated Solutions

There are no known corresponding expansions among neighbouring LDCs that could be addressed through integrated transmission solutions at this time.

Conclusion

The OPA finds that Innisfil Hydro's Basic GEA Plan is reasonably consistent with the OPA's information regarding renewable energy generation applications to date.

The OPA appreciates the opportunity to comment on Innisfil Hydro's Basic GEA Plan.

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APPENDIX E

GEA FUNDING JUSTIFICATION

COS - Cost Justification

The future plans for ***Smart Grid/Green Energy*** implementation at Innisfil Hydro Distribution Systems Limited (IHDSL) are guided by the recommendations published by the Ontario Executive Council and the Ministry of Energy, as stated below:

> *It is desirable that the Province and the Ontario Energy Board move forward with a plan to implement the advanced information exchange systems and equipment that together comprise the Smart Grid, as defined in the amendments to the Electricity Act, 1998, made by the Green Energy and Green Economy Act, 2009*
>
> *And in furtherance to this goal, it is desirable that the Province provide guidance and direction to the Board as to the principles and objectives which must be met in order to fully achieve the Province's objectives related to the Smart Grid in a cost-efficient manner.*
>
> In accordance with the *Directives issued by the Lieutenant Governor in Council pursuant to section 28.5 of the Ontario Energy Board Act, 1998, as amended by the Green Energy and Green Economy Act, 2009, in relation to the establishment, implementation, or promotion of a Smart Grid in Ontario*, we at IHDSL have prepared the plan described herein to continue to advance our Smart Grid and Green Energy implementation.
>
> In developing our five year forecast we have chosen projects that will enable us to install and commission equipment and advanced information sharing systems that, when utilized together, will improve flexibility, security, reliability, efficiency, and safety of our integrated distribution system.

Based on the above guidelines we have prepared an investment strategy as outlined below for the next five years and have prepared the following explanations for each budget item. Through the execution of this plan it is our expectation, among other benefits realized by our customers, to enable the increased use of renewable energy sources and technology, and accommodate the use of emerging and innovative technologies and system control applications.

1. Recloser Automation, Replacement, & Line Recloser Maintenance (4 year cycle) – funded through the 5 year capital plan

Description	Budget $				
	2013	2014	2015	2016	2017
Recloser Automation, Replacement, & Line Recloser Maintenance (4 year cycle)	$ 223,300	$ 232,000	$ 248,500	$ 265,900	$ 253,200

Overview:

IHDSL currently has eight (8) three-phase reclosers and 82 single-phase reclosers installed and fully operational on its distribution infrastructure. While all eight (8) three-phase reclosers are radio controlled and serve as circuit breakers inside three (3) of our Distribution Stations (DS), 45 single phase hydraulic reclosers serve as protective devices for station transformers inside the other six (6) of our DS'. The remaining 37 single-phase hydraulic reclosers are installed on our distribution lines. Over the next five (5) years it is our intention to replace all hydraulic reclosers in our DS' and start replacing our line reclosers at strategic locations with vacuum type units with electronic controls and radio communication.

Benefits:

1. Improve reliability
    a. Replacing old reclosers will reduce outages caused by mechanical failures, and improve our SAIFI, and SAIDI[1] metrics.
    b. Analyzing momentary outages to find the root causes (for transient outages) will enhance our ability to identify risks and hazards on our system early, and take corrective measures to prevent sustained outages.
2. Better tracking of momentary interruptions
    a. Installing reclosers with electronic controls will help develop, track, and report MAIFI metrics
3. Improve SCADA[2] versatility

[1] SAIFI: System Average Interruption Frequency Index; SAIDI: System Average Interruption Duration Index
[2] SCADA: Supervisory Control And Data Acquisition

a. The installation of radio controlled reclosers will enable more efficient switching, fault isolation and restoration.

4. Smart Grid Implementation
   a. This new system will contribute towards the implementation of a self-healing and self-correcting gird infrastructure to automatically anticipate and respond to system disturbances for faster restoration, as outlined in Appendix "B" of the Minister's Directive pursuant to section 28.5 of the Ontario Energy Board Act, 1998.
   b. This project will also enable us to use emerging, and innovative technology in our gird.
5. Beneficial to the environment
   a. Replacing oil filled reclosers with vacuum interrupters reduces the possibility of environmental contamination that may occur when a hydraulic recloser spills oil.

Scope:

1. During each of the following five (5) years we intend to install approximately four (4) sets of reclosers with electronic controls and radio connectivity capability to interface with our SCADA system.
   a. We intend to install G&W Viper® reclosers with Schweitzer® (SEL) 651R controllers and DNP3[3] protocol.

2. 44kV SCADA Controlled Load Interrupting Gang Switches - funded through the 5 year capital plan

Description	Budget $				
	2013	2014	2015	2016	2017
44kV SCADA Controlled Load Interrupting Gang Switches	$ 160,100	$ 166,300	$ 178,200	$ 190,600	$ 203,000

[3] DNP3: Distributed Network Protocol (a set of communication protocols used between components in automation systems)

Overview

We currently have 31 SCADA controlled Load Interrupting Gang Switches on our 44kV subtransmission infrastructure. Since 1996 when IHDSL was starting to invest in Smart Grid technology these switches were gradually introduced to the grid.

Benefits

1. Improve reliability
    a. Replacing our older load interrupting switches with new switches will reduce outages caused by switch failures, and improve our SAIFI, and SAIDI metrics.
    b. Replacing our older switches also reduces downtime caused by obsolescence, as we are finding it harder to source replacement parts.
    c. The older switches are being replaced as part of our “end of life” replacement program.
    d. Since we intend to replace the non-load-break (air-break) switches, in-line, and mid span openers with SCADA controlled load-break type, this further reduces switching and restoration times and is expected to further improve our SAIDI metrics.
    e. Adding new switches at strategic locations will also improve our options to sectionalize a faulted portion of our grid and reduce customers impacted during an outage.
2. Improve SCADA versatility
    a. The installation of radio controlled load interrupting gang switches have increased functionality and will enable more efficient switching, fault isolation, and restoration of our subtransmission infrastructure through remote switching by our control centre personnel.
3. Smart Grid Implementation
    a. The installation of radio controlled load interrupting gang switches will be a step in the direction of converting our subtransmission infrastructure to Smart Grid.
    b. This project will also enable us to use emerging, and innovative technology in our gird.

Scope

1. During each of the following five (5) years we intend to install two (2) radio controlled load interrupting gang switches to interface with our SCADA system.
    a. We intend to install S&C AldutiRupter® type switches with M-Series® controls and DNP3 protocol.

3. 27.6kV SCADA Controlled Load Interrupting Gang Switches - funded through the 5 year capital plan

Description	Budget $				
	2013	2014	2015	2016	2017
27.6kV SCADA Controlled Load Interrupting Gang Switches	$ 253,200	$ 263,100	$ 281,700	$ 301,500	$ 321,000

Overview

We currently have six (6) SCADA controlled Load Interrupting Gang Switches on our 27.6kV distribution infrastructure. As noted above, since 1996 IHDSL has been investing in Smart Grid technology, and in 2008 started to gradually introduce these switches into the distribution grid.

Benefits

1. Improve reliability
    a. Replacing our older load interrupting switches with new switches will reduce outages caused by switch failures and inoperability, and improve our SAIFI, and SAIDI metrics.
    b. Since we intend to replace in-line switches with SCADA controlled load-break type, this further reduces switching and restoration times and improves our SAIDI metrics.
    c. Adding new switches at strategic locations will also improve our options to sectionalize a faulted portion of our grid and reduce customers impacted during an outage.

2. Improve SCADA versatility
    a. The installation of radio controlled load interrupting gang switches will enable more efficient switching, fault isolation and restoration of our 27.6kV distribution infrastructure through remote switching by our control centre personnel.
3. Smart Grid Implementation
    a. The installation of radio controlled load interrupting gang switches will be a step in the direction of converting our distribution infrastructure to Smart Grid.
    b. This project will also enable us to use emerging, and innovative technology in our gird.

Scope

1. During each of the following five (5) years we intend to install three (3) radio controlled load interrupting gang switches to interface with our SCADA system.
    a. We intend to install both S&C Scada-Mate® type switches with 6800 Series Automatic Switch Controls, and G&W Viper® reclosers with Schweitzer® (SEL) 651R controllers. Both switches communicate using DNP3 protocol.

4. Implementation of Automated Sectionalization and Restoration (ASR) – Require funding

Description	Budget $				
	2013	2014	2015	2016	2017
Implementation of Automated Sectionalization and Restoration (ASR)	$ 250,000	$ 250,000	$ 250,000	$ 250,000	$ 250,000

Overview

As part of our grid automation program we intend to implement Automatic Sectionalizing and Restoration (ASR) schemes at strategic circuit tie points in our subtransmission and distribution backbone. This will enable a new level of automation within our grid. When fully configured, an ASR scheme would enable

automated fault isolation and partial restoration without the need for human interaction.

Benefits

1. Improve reliability
    a. The addition of automatic switching to pick up customers who have lost power on a given feeder by routing power to them through an alternate feeder would reduce customers experiencing permanent outages, and improve our SAIFI, and SAIDI metrics.
2. Improve SCADA versatility
    a. We intend to equip these switches with radio controls, which in turn will improve the decision making capability of our control centre staff during restoration efforts during system-wide outages.
3. Smart Grid Implementation
    a. This new system will contribute towards the implementation of a self-healing and self-correcting gird infrastructure to automatically anticipate and respond to system disturbances for faster restoration.
    b. This project will also enable us to use emerging, and innovative technology in our gird.

Scope

1. During each of the following five (5) years we intend to install a set of three (3) radio controlled switching devices (3-phase reclosers are to be installed on our distribution lines to act as switches, and motor operated gang switches on our subtransmission lines) at strategically located circuit ties to interface with our SCADA system.
    a. We intend to install G&W Viper® reclosers with Schweitzer® (SEL) 651R controllers and DNP3 protocol on the distribution system, and S&C AldutiRupter® type switches with M-Series® controls and DNP3 protocol on our subtransmission system.

5. Fault Current Indicators - funded through the 5 year capital plan

Description	Budget $				
	2013	2014	2015	2016	2017
Fault Current Indicators	$ 38,400	$ 39,900	$ 42,700	$ 45,700	$ 48,700

Overview

We currently have 114 radio controlled Fault Circuit Indicators (FCI) on both our subtransmission and distribution infrastructure. Some of these FCI's are nearing their effective life due to built-in battery wear. As part of our grid automation program we intend to install approximately six (6) to seven (7) sets of FCI's per year. The addition of these FCI's will enable us to reduce patrolling time during outages, and in turn reduce outage durations.

Benefits

1. Improve reliability
    a. The addition of FCI's will help isolate faulted circuit segments, thereby reducing patrol time/restoration time, and as a result improve our SAIDI metrics.
    b. Replacing the older FCI that are nearing their end of life will also improve the reliability of our fault detection system.
2. Improve SCADA versatility
    a. We intend to equip these FCI's with radio controls, which in turn will improve the decision making capability of our control centre personnel during outage restoration efforts.
3. Smart Grid Implementation
    a. The installation of radio controlled FCI's will be a step in the direction of converting our subtransmission and/or distribution infrastructure to Smart Grid.
    b. This project will also enable us to use emerging, and innovative technology in our gird.

Scope

1. During each of the following five (5) years we intend to install approximately six (6) to seven (7) sets of radio controlled FCI's at strategic locations to interface with our SCADA system.
    a. We are currently evaluating our product options and expect to finalize the specifications for FCI's shortly.

6. Smart Grid/Green Energy Engineer - funded through the 5 year capital plan

Description	2013	2014	2015	2016	2017
Smart Grid/Green Energy Engineer	100,000	103,000	106,100	109,270	112,550

Overview

We recently hired a Smart Grid/Green Energy Engineer to assist in the implementation of a variety of projects pertaining to grid modernization. These include the design, specification, and oversight of the implementation and maintenance of our proposed SCADA system, and the replacement of our existing radio equipment. This new engineer will also oversee the expansion of our radio communication infrastructure which will include the Town of Innisfil's Water and Waste Water monitoring facilities. Other duties include working on Distributed Generation and other Green Energy projects.

Benefits

1. Investing in a Smart Grid/Green Energy Engineer will enable us to continue our grid modernization projects in a timely manner.
2. We will be better prepared to face the challenges of the evolving technology within our industry and use it for the advantage of our customers.
3. Developing in-house expertise in the configuration, programming, installation and maintenance of Smart Grid technology within our grid will give us the capability to take better control of the grid modernization process by

reducing our dependencies on external consultants and contractors. This reduces our operating costs and helps speed up the change process as well.

Scope

1. During each of the following five (5) years our Smart Grid/Green Energy Engineer will be contributing towards projects aimed at modernizing our subtransmission and distribution grids. The specific tasks of this engineer will evolve over a period of time as we move through the various phases of grid modernization; however, we foresee the following areas to take up his time in the near future:
    a. Recloser Automation & Replacement,
    b. 44kV SCADA Controlled Load Interrupting Gang Switch installation,
    c. 27.6kV SCADA Controlled Load Interrupting Gang Switch installation,
    d. Implementation of Automated Sectionalization and Restoration (ASR),
    e. Fault Current Indicator installation,
    f. New SCADA system installation and commissioning,
    g. Radio Communication system installation and commissioning,
    h. Communication protocol upgrade,
    i. Enterprise-wide data integration,
    j. Design, install and commission two (2) DS',
    k. Upgrade two (2) Distribution transformers at DS',
    l. Install five (5) SCADA controlled pad-mount switch gear,
    m. Install four (4) SCADA controlled capacitor interrupters,
    n. Design and commission the new Control Room,
    o. Green Energy/Distributed Generation project review, authorization, and interface to Smart Grid,
    p. Supervise the Support Technician we intend to hire for Smart Grid/Green Energy system implementation and maintenance, if funded.

7. Support Technician for Smart Grid/Green Energy Projects - Require funding

Description	2013	2014	2015	2016	2017
Support Tech	75,000	77,250	79,600	82,000	84,460

Overview

We intend to hire a Support Technician to work on projects pertaining to Smart Grid and Green Energy projects. This technician will work on all aspects of project implementation, commissioning, maintenance, and trouble shooting, which will help us develop in-house expertise.

An added benefit in adding this new position to our team of technicians will be the improvement in our Key Performance Metrics pertaining to our response times for completing Locate requests. Currently our station inspections and SCADA device equipment and battery inspection are done by a team of two technicians who are also responsible for completing all Locates, meeting customer requests for new service and service upgrades, and preparing layouts for Micro-FiT projects. Given our increased work load due to (1) the large number of Micro-FiT connection requests, (2) increase in underground Locate requests, and (3) increase in the number of service upgrades due to home renovations, we are finding it a challenge to meet our obligations to our customers in a timely manner, including the 5-day turn around for Locate requests, This new technician for whom we are seeking funding is expected to take over our station inspection work and SCADA equipment and battery inspection, releasing our current resources to spend more time with meeting the various customer requests noted above. This will help us improve our response times for Locates, and other customer obligations, which in turn will help meet our obligations to the OEB

With the scope of work listed in the five year plan, particularly with the pending implementation of a new protocol, and the replacement of our radio communication equipment, we intend to install a significant amount of hardware throughout our service territory, which would require the services of a qualified technician (electrical/electronic technician) during the implementation phase as well as for the maintenance, upkeep, and trouble shooting of the new and existing equipment.

As we install and commission our new SCADA system it is our intent to design, configure, equip, and commission a new Control Room in our new office building which we are planning on occupying at the end of 2013. This new technician will play an important role on the design, implementation, and up keep of the systems and equipment in the new Control Room.

Benefits

1. Investing in a Smart Grid/Green Energy Technician will enable us to continue our grid modernization projects in a timely manner.

2. We will be better prepared to face the challenges of the evolving technology within our industry and use it for the advantage of our customers.
3. Developing in-house expertise in the maintenance, and up keep of Smart Grid technology will give us the capability to take better control of the grid modernization process by reducing our dependencies on external consultants and contractors. This reduces our operating costs and helps speed up the change process as well.
4. Improve our response time for locates and layouts, as it will free up time for our current technical staff from doing station inspections and battery checks/SCADA equipment inspections.
5. Enable timely implementation of proposed action items noted in the table below.

Scope

1. During each of the following five (5) years our Smart Grid/Green Energy Support Technician will be contributing towards projects aimed at modernizing our subtransmission and distribution grids. We expect the technician to be involved in the tasks listed in the table below.

Justification - Labour Hours Breakdown

Description	2013	2014	2015	2016	2017
a. Recloser Automation & Replacement: Maintenance and Upkeep	120	120	120	120	120
b. 44kV SCADA Controlled Load Interrupting Gang Switch: Maintenance and Upkeep	80	80	80	80	80
c. 27.6kV SCADA Controlled Load Interrupting Gang Switch: Maintenance and Upkeep	80	80	80	80	80
d. Automated Sectionalization and Restoration (ASR): maintenance & trouble shooting	80	80	80	80	80
e. Fault Current Indicator: maintenance & trouble shooting	120	120	120	120	120
f. SCADA system: maintenance, upkeep, & trouble shooting	600	600	600	600	600
g. Radio Communication system: maintenance, upkeep, & trouble shooting	600	600	600	600	600
h. Communication protocol upgrade, maintenance & trouble shooting	120	120	120	120	120
i. Distribution Station Maintenance	160	160	160	160	160
j. SCADA equipment battery check & equipment inspection	120	120	120	120	120
TOTAL	2080	2080	2080	2080	2080

Other opportunities for technical support					
1. Green Energy projects: site surveys, interfacing with customer electrician, prepare layout, etc	200	200	200	200	200
2. Fiber communication system maintenance and trouble shooting	80	80	80	80	80
3. OMS data review and correction, & outage follow up	260	260	260	260	260
4. FDIR system: assist Smart Grid Engineer with system check and trouble shooting	104	104	104	104	104
5. Water and Waste Water - Radio System: maintenance and trouble shooting	150	150	150	150	150
6. Miscellaneous field surveys, patrols, data verification, etc.	104	104	104	104	104

8. New SCADA System – Phase 1 (2012 scope) is funded through the 5 year capital plan; while Phase 2 (2013 scope) requires additional funding

Description	2012	2013	2014	2015	2016	2017
New SCADA System	200,000	250,000	0	0	0	0

Phase 1: Direct replacement of old (base) SCADA system

Phase 2: Adding functionality to base SCADA system

Overview

Our current SCADA system was designed and built in 1996 using generic automation software to include the monitoring and control of a select number of data points on our subtransmission and distribution infrastructure. Among the 9 DS' we currently own, we have limited visibility on all, but have the ability to control protective devices on only three (3) DS'. Upgrading our SCADA system to a scalable utility specific technology will enable us to monitor and control an unlimited number of data points within our subtransmission and distribution infrastructure.

Implementation Schedule: Spread Over Two (2) Years

We intend to complete a direct replacement of our existing SCADA system in 2012 for which we have received sufficient funding. The proposed scope includes the purchase and commission the a base SCADA system; however, the extra funding we are requesting for 2013 will cover the cost of creating a more reliable and robust system with added capabilities such as (1) built-in redundancies with dual servers; (2) customized FDIR system to enable auto switching and restoration; (3) enhanced OMS system to better track our outages and gather intelligence to perform Root Cause Analysis (RCA) on major/recurring outages, and (4) effective and timely integration of operations data with other enterprise systems to maximize our Situational Awareness and Business Intelligence.

As we install and commission our new SCADA system it is our intent to configure and equip a new Control Room in our new office building which we are planning on occupying at the end of 2013.

Justification

1. Currently we have limited or no visibility on the 27.6kV, and 8.32kV distribution line.
2. Limited programming capability: lacking registers for Input and Output variables, timers etc.
3. Outdated Windows OS compatibility (Supports WinXP or lower).
4. Needs separate software for overview, trending and reporting.
5. Cannot be integrated with other software; i.e. GIS, AMI, OMS[4], etc. Therefore it cannot be used for automation or decision making.
6. Limited Graphical User Interface (GUI)
7. System reliability issues: we have experienced several malfunctions of our SCADA system over the years and expect to considerably improve system up-time with the implementation of the new system.

Selection criteria of new system

1. Automatic collection of data from multiple applications throughout the Innisfil Hydro network (44kV, 27.6kV, & 8.32kV).
2. Adapting an integrated communication medium that can handle data from multiple applications located throughout our infrastructure.
3. Integration of application software suits (GIS, SCADA, OMS, etc.) so they share collected data.
4. Ability to implement Distribution Automation, Advanced Metering Infrastructure, Demand Response - without rebuilding the system from the ground up.

System Performance Requirements

1. Enterprise-wide System integration: Customer Service, Operations, Engineering and Management to operate as a team, all having secure, and reliable access to the same pool of real-time information.

[4] GIS: Geographic Information Systems, AMI: Advanced Metering Infrastructure, OMS: Outage Management System

2. Business intelligence/Situational Awareness: Turn the volumes of real time and historical data into useful information.
3. Scalable system: Grows with the company and technological requirements.
4. Multiple protocols: Easy to implement, flexible in communications infrastructure.
5. Easy to use: Detailed graphical user interface.
6. Security: Safe system with proven security.
7. Reliability: Added reliability with the implementation of a redundant SCADA server.
8. Product support: Able to provide technical expertise needed to effectively operate and maintain Smart Grid/Green Energy systems.

Benefits

1. Improved Operational Efficiency: The new SCADA system will help us to:
    a. respond to outages faster,
    b. isolate faulted segments of the feeder more rapidly,
    c. identify fault locations quicker,
    d. determine type of faults more accurately, and
    e. dispatch our crews to the faulted location in a more timely manner.
2. The new SCADA system will serve as a foundation for the new Smart Grid technology implementation, adding a centralized location for adoption of applications such as DA, OMS, DMS, FDIR, EMS[5], etc.
3. This new system will contribute towards the implementation of a self-healing and self-correcting gird infrastructure to automatically anticipate and respond to system disturbances for faster restoration.
4. This project will also enable us to use emerging, and innovative technology in our gird.

[5] DA: Distribution Automation, OMS: Outage Management System, DMS: Distribution Management System, FDIR: Fault Detection, Isolation & Restoration, EMS: Energy Management System

Scope

1. It is our intent to purchase, install, and commission a new base SCADA system from Survalent® before the end of 2012, while phasing the full implementation through the end of 2013. The base system will include new computer hardware, electric utility specific SCADA software, while the add-ons will include the option to install redundant servers for greater reliability, switch order preparation software, web server, command sequencing program module, Multispeak interface to network with our GIS system, AMI interface, OMS, and FDIR.
2. Internal staff training is to be phased in during the implementation process.

9. Software Upkeep - Require funding

Description	2013	2014	2015	2016	2017
Software Upkeep	10,000	10,300	10,600	10,900	11,500

Overview

With the implementation of a SCADA system it becomes necessary to regularly update databases and screen displays as our system is modified. The budget cost reflects the amount charged by the software vendor for regular system maintenance, support, and updates.

Benefits

1. Maintaining system integrity and effectiveness.
2. Keeping up to date with latest software revisions.
3. Timely support for resolving trouble tickets.

10. Radio / WAN[6] / Automation Hardware Installation & Commissioning - Require funding

Description	2013	2014	2015	2016	2017
Radio / WAN / Automation Hardware Installation & Commissioning	200,000	0	0	0	0

Overview

- Radio

The main factor in the deployment of a successful smart grid is a well-developed communications plan and infrastructure. Currently our network is not reliable, as we have issues communicating with SCADA. Almost 50% of our communication points have intermittent connectivity problems. As the frequency used is unlicensed (900 MHz) there are other users of the spread spectrum, causing traffic congestion. Also, radio power levels are capped on unlicensed frequency spectrum, therefore it limits our ability to improve signal strength. A new communications network would provide us with an opportunity to migrate towards a more reliable and robust communication infrastructure utilizing the dedicated frequency allocated by Industry Canada for electric utilities.

- Protocol

Automation devices communicate using either standard or proprietary protocols. Currently almost 70% of our DS equipment is based on the OptoMux proprietary protocol which is outdated and incompatible with newer technologies. The remaining devices are based on a current industry standard, namely the DNP3 protocol. Migrating the OptoMux equipment to the standard DNP3 protocol will allow us the capability to install industry standard components with ease of integration.

[6] WAN: Wide Area Network

Benefits

1. Radio Frequency path reliability close to 100%.
2. An optimized wireless communication network, reducing number of components.
3. Redundancies in the system, so there is a backup path for communication if there is a failure.
4. Enable communication with renewable generation installations.
5. Scalable network capable of handling growing communication points, with wide coverage throughout our service territory.
6. We can share the network with other utilities; i.e. water and waste water, for cost sharing.
7. Transition from serial to Ethernet: From packet based to Internet Protocol (IP) based network.
8. This new communication will contribute towards the implementation of a self-healing and self-correcting gird infrastructure to automatically anticipate and respond to system disturbances for faster restoration.
9. This project will also enable us to use emerging, and innovative technology in our gird.

Scope

1. We intend to replace 70 transceivers and antenna points during 2013 to the devices that use the new licensed frequency.
2. Replacing 23 OptoMux automation controllers to DNP3 type.

END OF REPORT

APPENDIX F

GREEN ENERGY PLAN ADDER

GREEN ENERGY PLAN – FUNDING ADDER

IHDSL has submitted a basic Green Energy Plan to the OPA and has provided a copy in Appendix C. The OPA provided a Letter of Comment which has been provided in Appendix D.

As part of its GEA Plan, IHDSL has estimated the following capital and OM&A expenditures for 2013, 2014 and 2015.

IHDSL requests a funding adder to be included in its rates of $0.5233 (average of the 3 years) per Residential, GS>50kW and GS<50kW -4,999kW per month. The finding adder calculations were based on the Incremental Revenue Requirement Calculation provided below. An electronic version of this model has been provided as part of this application.

GEA Incremental Revenue Requirement Calculation

	2013		2014		2015		
Net Fixed Assets		$ 710,000		$260,000		$ 261,000	
OM&A	$ 75,000		$ 77,000		$ 80,000		
WCA	13.0%	$ 9,750	13.0%	$ 10,010	13.0%	$ 10,400	
Rate Base		$ 719,750		$270,010		$ 271,400	
Deemed ST Debt	4%	$ 28,790	4%	$ 10,800	4%	$ 10,856	
Deemed LT Debt	56%	$ 403,060	56%	$151,206	56%	$ 151,984	
Deemed Equity	40%	$ 287,900	40%	$108,004	40%	$ 108,560	
ST Interest	2.08%	$ 599	2.08%	$ 225	2.08%	$ 226	
LT Interest	5.11%	$ 20,596	5.11%	$ 7,727	5.11%	$ 7,766	
ROE	8.01%	$ 23,061	8.01%	$ 8,651	8.01%	$ 8,696	
		$ 44,256		$ 16,602		$ 16,688	
OM&A		**$ 75,000**		**$ 77,000**		**$ 80,000**	
Amortization		$ 25,278		$ 53,333		$ 58,889	
Grossed-up PILs		-$ 2,371		-$ 17,161		-$ 15,689	
Revenue Requirement		$ 142,163		$129,774		$ 139,887	
Direct Benefit							
OM&A		$ 75,000		$ 77,000		$ 80,000	
Capital		$ 67,163		$ 52,774		$ 59,887	
Direct Benefit % on capital		0.00%		55.25%		41.00%	
Direct Benefit on capital		$ -		$ 29,156		$ 24,552	
Total Direct Benefit		$ 75,000		$106,156		$ 104,552	
Total # of Customers (Residential, GS<>50)		15,165		15,165		15,165	
GEA Rate Adder		$ 0.4121		$ 0.5833		$ 0.5745	3 year average $ 0.5233
Provincial Rate Protection		$ 67,163		$ 23,619		$ 35,335	
Monthly Adder Amount Paid by IESO		$ 5,597		$ 1,968		$ 2,945	

IHDSL has divided its expected expenditures into two categories, Renewable Enabling Improvements and Feeder Automation Projects, and has estimated the amortization for each category based on the weighted average depreciation rates for the type of expenditures anticipated in 2013, us ing rates established under MIFRS. Renewable Improvements are depreciated over 45 years and Feeder Automation over 10 years. 6% of Renewable Enabling Improvements Enabling expenses have been designated as Direct Benefit, with the balance assigned to Provincial Rate Protection. Table 6.1 Renewable Capital Investment, contains these details.

Table 6.1 Renewable Capital Investment

Renewable Connections Capital - Renewable Enabling Improvements				
RECLOSER		**2013**	**2014**	**2015**
Opening Capital Investment		$ -	$ 250,000	$ 500,000
Capital Investment		$ 250,000	$ 250,000	$ 250,000
Closing Capital Investment		$ 250,000	$ 500,000	$ 750,000
Opening Accumulated Amortization		$ -	$ 2,778	$ 11,111
Amortization Year One	45 Years	$ 2,778	$ 2,778	$ 2,778
Amortization Thereafter		$ -	$ 5,556	$ 11,111
Closing Accumulated Amortization		$ 2,778	$ 11,111	$ 25,000
Opening Net Fixed Assets		$ -	$ 247,222	$ 488,889
Closing Net Fixed Assets		$ 247,222	$ 488,889	$ 725,000
Average Net Fixed Assets		$ 123,611	$ 368,056	$ 606,944
Feeder Automation Projects				
SCADA		**2013**	**2014**	**2014**
Opening Capital Investment		$ -	$ 450,000	$ 450,000
Capital Investment		$ 450,000	$ -	$ -
Closing Capital Investment		$ 450,000	$ 450,000	$ 450,000
Opening Accumulated Amortization		$ -	$ 22,500	$ 67,500
Amortization Year One	10 years	$ 22,500	$ -	$ -
Amortization Thereafter		$ -	$ 45,000	$ 45,000
Closing Accumulated Amortization		$ 22,500	$ 67,500	$ 112,500
Opening Net Fixed Assets		$ -	$ 427,500	$ 382,500
Closing Net Fixed Assets		$ 427,500	$ 382,500	$ 337,500
Average Net Fixed Assets		$ 213,750	$ 405,000	$ 360,000

Average Net Fixed Assets	**Direct Benefit %**	**2012**	**2013**	**2014**
Renewable Connections Capital - Expansions	17%	$ -	$ -	$ -
Renewable Connections Capital - Renewable Enabling Improvements	6%	$ 123,611	$ 368,056	$ 606,944
Feeder Automation Projects	100%	$ -	$ 405,000	$ 360,000
		$ 123,611	$ 773,056	$ 966,944
Direct Benefit		$ 7,417	$ 427,083	$ 396,417
Weighted Average Direct Benefit %		0.00%	55.25%	41.00%

Using these capital investment estimates IHDSL has estimated the incremental revenue requirement as shown below in Table 6.2. The incremental revenue calculation has been adjusted for PILS (Table 6.3). IHDSL proposes to recover $ 285,708 of this amount from its customers as a direct benefit thru a fixed monthly funding adder of $0.5233 per customer. IHDSL proposes to recover the remaining through Provincial Rate Protection and requests a funding adder from the IESO for $3,503 per month.

When these costs are finalized at the end of 2015 IHDSL will come forward with a cost recovery application including a true-up rider and revenue collection rider to collect/disperse any variances from these amounts.

Table 6.2 Incremental Revenue Requirement & Funding Adder Calculation

Direct Benefit				
OM&A	$ 75,000	$ 77,000	$ 80,000	
Capital	$ 67,163	$ 52,774	$ 59,887	
Direct Benefit % on capital	0.00%	55.25%	41.00%	**Total for Recovery**
Direct Benefit on capital	$ -	$ 29,156	$ 24,552	**2013-2015**
Total Direct Benefit	$ 75,000	$106,156	$ 104,552	$ 285,708
Total # of Customers (Residential, GS<>50)	15,165	15,165	15,165	
				3 year average
GEA Rate Adder - Monthly Fixed Charge	$ 0.4121	$ 0.5833	$ 0.5745	$ 0.5233
Provincial Rate Protection	$ 67,163	$ 23,619	$ 35,335	$ 126,117
Monthly Adder Amount Paid by IESO	$ 5,597	$ 1,968	$ 2,945	$ 3,503

Table 6.3 PILS Calculation

PILs Calculation			
	2013	2014	2015
INCOME TAX			
Net Income	$ 23,061	$ 8,651	$ 8,696
Amortization	$ 25,278	$ 53,333	$ 58,889
CCA	-$ 55,000	-$ 110,200	-$ 111,664
Change in taxable income	-$ 6,661	-$ 48,216	-$ 44,079
Tax Rate	26.25%	26.25%	26.25%
Income Taxes Payable	-$ 1,749	-$ 12,657	-$ 11,571
ONTARIO CAPITAL TAX			
Closing Net Fixed Assets	$ 247,222	$ 488,889	$ 725,000
Less: Exemption	$ -	$ -	$ -
Deemed Taxable Capital	$ 247,222	$ 488,889	$ 725,000
Ontario Capital Tax Rate			
Net Amount (Taxable Capital x Rate)	$ -	$ -	$ -
Gross Up			
	PILs Payable	PILs Payable	PILs Payable
Change in Income Taxes Payable	-$ 1,748.63	-$ 12,656.58	-$ 11,570.86
Change in OCT	$ -	$ -	$ -
PIL's	-$ 1,748.63	-$ 12,656.58	-$ 11,570.86
	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs
Change in Income Taxes Payable	-$ 2,371.02	-$ 17,161.47	-$ 15,689.30
Change in OCT	$ -	$ -	$ -
PIL's	**-$ 2,371.02**	**-$ 17,161.47**	**-$ 15,689.30**

Exhibit	Tab	Schedule	Appendix	Contents
3 – Operating Revenue				
	1	1		Overview of Operating Revenue
	2	1		Weather Normalized Load and Customer/ Connection Forecast
	2		A	Monthly Data Used for Regression Analysis
	3	1		Operating Revenue Variance Analysis.
	3	2		Transformer Allowance
	3	3		Variance Analysis on Other Distribution Revenue

OVERVIEW OF OPERATING REVENUE:

This Exhibit provides the details of IHDSL's operating revenue for 2009 Board Approved, 2009 Actual, 2010 Actual, 2011 Actual, the 2012 Bridge Year and the 2013 Test Year. This Exhibit also provides a detailed variance analysis by rate class of the operating revenue components. Distribution revenue excludes revenue from commodity sales.

IHDSL's is proposing a total Service Revenue Requirement of $9,419,635 for the 2013 Test Year. This amount includes a Base Revenue Requirement of $ 8,862,687, plus revenue offsets of $556,948 to be recovered through Other Distribution Revenue.

A summary of all operating revenue is presented below in Table 3.1.1 and provides a comparison of total revenues from the 2009 OEB approved year to the 2013 Test Year.

Throughput Revenue:

Information related to IHDSL's throughput revenue includes details on the weather normalized load forecasting methodology reflecting expected CDM results and a forecast of customers by rate class based on the historical number of customers billed throughout the year.

A detailed variance analysis on the historical throughput revenue is also provided in this Exhibit.

Other Revenue:

Other revenues include Standard Service Supply (SSS) Administration Charges, Late Payment Charges, Miscellaneous Service Revenues and Merchandise and Jobbing Revenues.

A detailed variance analysis on other revenue is set out later on this Exhibit.

Table 3.1.1 Summary of Operating Revenues

Operating Revenue	2009 OEB Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge CGAAP	2013 Test MIFRS
Distribution Revenue						
Residential	6,011,508	5,660,360	5,797,125	5,882,306	6,187,519	7,234,973
GS<50kW	721,481	652,527	602,655	579,267	637,500	629,481
GS>50kW-4,999 kW	735,939	765,550	754,396	661,641	696,500	518,208
Sentinel Lights	6,467	11,995	19,055	22,990	29,300	37,807
Street Lighrts	43,398	131,366	231,528	305,463	317,200	422,247
Unmetered Scattered Load	44,918	34,771	41,669	41,084	43,500	19,972
Total	**7,563,711**	**7,256,569**	**7,446,428**	**7,492,751**	**7,911,519**	**8,862,688**
% of Total Revenue		**93%**	**94%**	**92%**	**102%**	**94%**
Other Distribution Revenue						
Specific Service Charge -4235	135,935	142,194	127,673	166,067	149,670	154,100
Late Payment Charge -4225	89,542	105,597	111,120	104,841	110,402	113,700
Retail Services Revenue -4082	26,269	35,349	42,813	78,272	54,203	55,033
Pole Rental -4210	145,208	154,992	161,381	157,442	162,676	167,600
Regulatory Debit - 4305	-	-	-	-	- 639,864	-
Special Purpose - 4325	-		49,901			
Gain (Loss) on Disposal -4355	-	33,840	-	- 126,618	- 51,476	- 48,825
Misc-Non Utility Income -4375	169,431	377,961	287,996	279,583	384,806	500,668
Misc-Non Utility Exp -4380	- 169,431	- 331,366	- 389,430	- 268,700	- 405,862	- 469,228
Misc Non Utiliy Income -4390	7,053	9,629	52,823	24,952	30,009	30,900
Interest Income - 4405	34,300	23,617	36,839	53,328	14,600	3,000
SRED Revenue -4406	-	-	-	153,377	50,000	50,000
Total Other Distribution Rev	**438,307**	**551,813**	**481,116**	**622,544**	**- 140,836**	**556,948**
% of Total Revenue	**5%**	**7%**	**6%**	**8%**	**-2%**	**6%**
Grand Total	**8,002,018**	**7,808,382**	**7,927,544**	**8,115,295**	**7,770,683**	**9,419,636**

WEATHER NORMALIZED LOAD AND CUSTOMER/CONNECTION FORECAST

The purpose of this evidence is to present the process used by IHDSL to prepare the weather normalized load and customer/connection forecast used to design the proposed 2013 electricity distribution rates.

In summary, IHDSL has used the same regression analysis methodology used by a number of distributors in previous cost of service rate applications to determine a prediction model. With regard to the overall process of load forecasting, IHDSL submits that conducting a regression analysis on historical electricity purchases to produce an equation that will predict purchases is appropriate. IHDSL has the data for the amount of electricity (in kWh) purchased from the IESO for use by IHDSL's customers. With a regression analysis, these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month. The results of the regression analysis produce an equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for the Bridge Year and the Test Year which is converted to bill kWh by rate class. A detailed explanation of the process is provided later in this evidence.

During proceedings related to the 2009 and 2010 cost of service applications for a number of other distributors, Intervenors expressed concerns with the load forecasting process that was proposed at the time by those distributors. During the review process of the 2009 cost of service applications, Intervenors suggested the regression analysis should be conducted on an individual rate class basis and the regression analysis would be based on monthly kWh by rate class. IHDSL attempted to conduct the regression analysis on an individual rate class basis. IHDSL estimated the amount consumed in a month by rate class using an equation to prorate billing that was used in the process for unbilled revenue. However, based on the R square and Adjusted R square values shown in the following table, IHDSL concluded using the equation resulting from the individual rate class regression analysis would not provide individual class based prediction formulas that were as good as the prediction equation from the power purchased method. The R

square and Adjusted R square values for the power purchased method are 98% and 97%, respectively. In addition, the total 2013 kWh forecast would be slightly lower using the individual rate class prediction formula.

Table 3-1: R Square and Adjusted R Square Values for Individual Class Regression Analysis

Class	R Square	Adjusted R Square
Residential	97%	97%
GS<50	78%	77%
GS>50	8%	3%

During the review of 2010 cost of service applications, Board staff and Intervenors expressed concern that the regression analysis assigned coefficients to some variable that were counter intuitive. For example, the customer variable would have a negative coefficient assigned to it which meant as the number of customers increased as the energy forecast decreased. 2010 applicants explained that this was related to the recent Conservation and Demand Management ("CDM") savings in the utility but in the view of Board staff and Intervenors this was not a sufficient explanation. Further, the regression analysis indicated that some of the variables used in the load forecasting formula were not statistically significant and should not have been included in the equation. IHDSL has attempted to address these concerns in the load forecast used in this Application. Based on the OEB's approval of this methodology in a number of previous cost of service applications, and based on the discussion that follows, IHDSL submits that its load forecasting methodology is reasonable for the purposes of this Application.

The following provides the material to support the weather normalized load forecast used by Innisfil Hydro in this Application.

Table 3-2: Summary of Load and Customer/Connection Forecast						
Year	**Billed (GWh)**	**Growth (GWh)**	**Percent Change**	**Customer/ Connection Count**	**Growth**	**Percent Change (%)**
Billed Energy (GWh) and Customer Count / Connections						
2009 Board Approved	227.2			17,499		
2002 Actual	202.2			15,267		
2003 Actual	213.8	11.6	5.7%	15,600	333	2.2%
2004 Actual	214.6	0.8	0.4%	15,990	390	2.5%
2005 Actual	226.0	11.4	5.3%	16,287	297	1.9%
2006 Actual	219.4	(6.6)	(2.9%)	16,394	107	0.7%
2007 Actual	219.8	0.4	0.2%	16,645	251	1.5%
2008 Actual	226.8	7.1	3.2%	17,044	399	2.4%
2009 Actual	229.1	2.3	1.0%	17,361	317	1.9%
2010 Actual	231.9	2.7	1.2%	17,552	191	1.1%
2011 Actual	233.6	1.7	0.7%	17,776	224	1.3%
2012 Bridge	**231.9**	**(1.6)**	**(0.7%)**	**18,070**	**294**	**1.7%**
2013 Test	**231.1**	**(0.8)**	**(0.4%)**	**18,369**	**299**	**1.7%**

The information in the table above provides weather actual data from 2002 to 2011, while 2012 and 2013 are weather normalized. IHDSL does not have a process to properly adjust weather actual data to a weather normal basis. However, based on the process outlined in this Exhibit, a process to forecast energy on a weather normalized basis has been developed and used in this Application.

Total Customers and Connections are on a mid-year basis and streetlight, sentinel lights and unmetered loads are measured as connections.

Actual and forecasted billed amounts and numbers of customers are shown in Table 3-3 and customer usage is shown in Table 3-4, on a rate class basis.

Table 3-3: Billed Energy and Number of Customers / Connections by Rate Class								
Year	**Residential**	**GS<50**	**GS>50**	**Street Lighting**	**Sentinels**	**USL**	**Hydro One Load Transfers**	**Total**
Billed Energy (GWh)								
2009 Board Approved	153.8	31.0	40.0	1.6	0.1	0.6		227.1
2002 Actual	138.7	22.3	38.9	1.2	0.1	0.0	1.1	202.2
2003 Actual	147.4	25.0	38.8	0.9	0.1	0.0	1.7	213.8
2004 Actual	148.8	26.9	36.3	1.2	0.1	0.0	1.2	214.6
2005 Actual	154.8	28.3	39.8	1.5	0.1	0.0	1.5	226.0
2006 Actual	149.1	27.2	39.8	1.4	0.1	0.3	1.4	219.4
2007 Actual	148.7	28.5	39.3	1.5	0.1	0.5	1.1	219.8
2008 Actual	150.0	28.4	45.3	1.5	0.1	0.5	1.0	226.8
2009 Actual	150.4	28.1	47.5	1.6	0.1	0.5	1.0	229.1
2010 Actual	148.3	29.2	51.1	1.6	0.1	0.5	1.0	231.9
2011 Actual	150.1	30.5	49.9	1.5	0.1	0.5	1.0	233.6
2012 Bridge	**147.7**	**30.9**	**50.3**	**1.5**	**0.1**	**0.5**	**0.9**	**231.9**
2013 Test	**146.6**	**31.4**	**50.9**	**1.5**	**0.1**	**0.6**	**0.0**	**231.1**
Number of Customers/Connections								
2009 Board Approved	13,512	827	72	2,810	193	85		17,499
2002 Actual	12,075	837	71	2,107	177	0		15,267
2003 Actual	12,299	852	72	2,196	181	0		15,600
2004 Actual	12,539	886	73	2,309	183	0		15,990
2005 Actual	12,748	907	72	2,371	189	0		16,287
2006 Actual	12,867	797	80	2,371	189	90		16,394
2007 Actual	12,991	819	71	2,489	186	89		16,645
2008 Actual	13,277	836	73	2,588	186	84		17,044
2009 Actual	13,533	855	72	2,625	193	83		17,361
2010 Actual	13,651	865	68	2,685	201	82		17,552
2011 Actual	13,779	896	67	2,728	225	81		17,776
2012 Bridge	**13,983**	**903**	**67**	**2,807**	**231**	**79**		**18,070**
2013 Test	**14,189**	**910**	**66**	**2,889**	**237**	**78**		**18,369**

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Table 3-4: Annual Usage per Customer/Connection by Rate Class						
Year	**Residential**	**GS<50**	**GS>50**	**Street Lighting**	**Sentinels**	**USL**
Energy Usage per Customer/Connection (kWh per customer/connection)						
2009 Board Approved	11,382	37,485	555,556	569	518	7,059
2002 Actual	11,485	26,625	547,243	556	748	
2003 Actual	11,983	29,293	538,389	431	752	
2004 Actual	11,866	30,395	497,310	536	739	
2005 Actual	12,144	31,204	553,123	617	697	
2006 Actual	11,588	34,117	497,886	610	698	3,242
2007 Actual	11,446	34,754	553,811	601	679	5,839
2008 Actual	11,295	33,971	620,129	593	668	6,050
2009 Actual	11,112	32,881	659,351	601	632	5,948
2010 Actual	10,867	33,744	751,894	588	581	6,020
2011 Actual	10,893	34,095	745,100	534	490	6,041
2012 Bridge	**10,567**	**34,194**	**755,041**	**528**	**464**	**6,787**
2013 Test	**10,329**	**34,559**	**769,813**	**521**	**439**	**7,626**
Annual Growth Rate in Usage per Customer/Connection						
2009 Board App. Vs. 2009 Actual	2.4%	14.0%	(15.7%)	(5.2%)	(18.0%)	18.7%
2002 Actual						
2003 Actual	4.3%	10.0%	(1.6%)	(22.5%)	0.4%	
2004 Actual	(1.0%)	3.8%	(7.6%)	24.5%	(1.6%)	
2005 Actual	2.3%	2.7%	11.2%	15.0%	(5.8%)	
2006 Actual	(4.6%)	9.3%	(10.0%)	(1.2%)	0.2%	
2007 Actual	(1.2%)	1.9%	11.2%	(1.4%)	(2.6%)	80.1%
2008 Actual	(1.3%)	(2.3%)	12.0%	(1.4%)	(1.7%)	3.6%
2009 Actual	(1.6%)	(3.2%)	6.3%	1.4%	(5.3%)	(1.7%)
2010 Actual	(2.2%)	2.6%	14.0%	(2.0%)	(8.2%)	1.2%
2011 Actual	0.2%	1.0%	(0.9%)	(9.2%)	(15.6%)	0.3%
2012 Bridge	**(3.0%)**	**0.3%**	**1.3%**	**(1.2%)**	**(5.4%)**	**12.3%**
2013 Test	**(2.2%)**	**1.1%**	**2.0%**	**(1.2%)**	**(5.3%)**	**12.4%**

LOAD FORECAST AND METHODOLOGY

IHDSL's weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on a multifactor regression model that incorporates historical load, weather, days in the month, spring/fall seasonal "flag" and number of customers from the three main classes (i.e. Residential, Gs < 50 kW and GS > 50 kW). Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Next, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression model. The forecast of customers by rate class is determined using a geometric mean analysis. For those rate classes that use kW for the distribution volumetric billing determinant, an adjustment factor is applied to the class energy forecast based on the historical relationship between kW and kWh.

A detailed explanation of the load forecasting process follows.

Purchased KWh Load Forecast

An equation to predict total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (heating and cooling degree days); days in month, spring/fall seasonal "flag" and number of customers from the three main classes. The regression model uses monthly kWh and monthly values of independent variables from January 2002 to December 2011 to determine a prediction formula with coefficients for each independent variable. This provides 120 monthly data points which represents a reasonable data set for use in a regression analysis. Consistent with the approach used by many other distributors in their cost of service applications, IHDSL submits that it is appropriate to review the impact of weather over the period January 2002 to December 2011 and then determine the average weather

conditions over this ten year period which would be applied in the prediction formula to determine a weather normalized forecast. However, in accordance with the OEB's Filing Requirements, IHDSL Hydro has also provided a sensitivity analysis showing the impact on the 2013 forecast of purchases assuming weather normal conditions for a 20-year trend of weather data.

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 following outlines the prediction model used by IHDSL to predict weather normal purchases for 2012 and 2013:

Innisfil Hydro's Monthly Predicted kWh Purchases

= Heating Degree Days * 13,945
+ Cooling Degree Days * 27,828
+ Number of Days in the Month * 593,131
+ Spring Fall Flag * (1,023,894)
+ Number of Customers - 3 Main Classes * 1,059
+ Intercept of (17,443,143)

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix 3-A.

The sources of data for the various data points are:

a) Environment Canada website for monthly heating degree day and cooling degree information. Weather data from Pearson International Airport was used.

b) The calendar provided information related to number of days in the month and the months defined to be spring or fall (i.e. March to May and September to November)

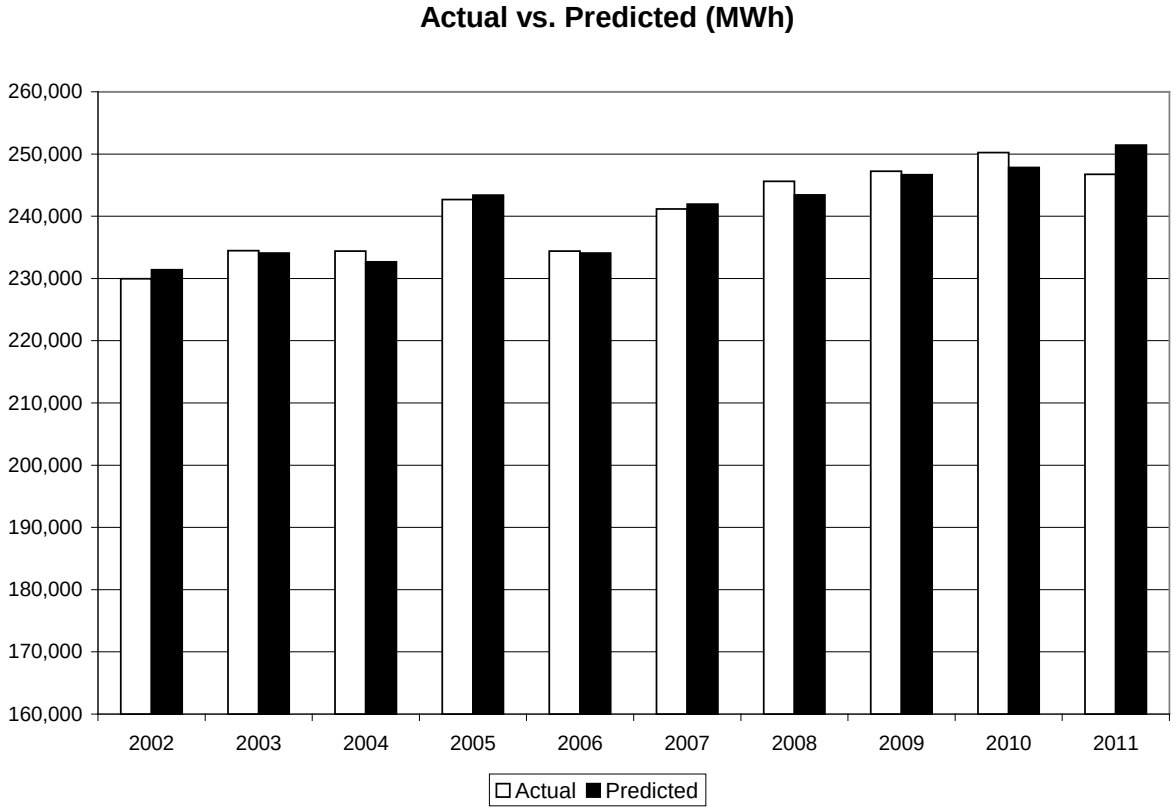
c) For January 2002 to December 2011 the number of customer for the 3 main classes was based on historical data from the billing system. For January 2012 to December 2013 the

forecast of customers for the 3 main classes was based on the mid-year forecast of customer discussed further on in this schedule for the Residential, GS < 50 kW and GS > 50 kW classes.

The resulting prediction formula has the following statistical results:

Table 3-5: Statistcial Results	
Statistic	**Value**
R Square	98%
Adjusted R Square	97%
F Test	916.7
T-stats by Coefficient	
Heating Degree Days	47.0
Cooling Degree Days	16.4
Number of Days in Month	10.4
Spring Fall Flag	(8.1)
Number of Customers - 3 Main Classes	13.8
Intercept	(8.7)

The annual results of the above prediction formula compared to the actual annual purchases from 2002 to 2011 are shown in the chart below. The chart indicates the resulting prediction equation appears to be reasonable.



The following table outlines the data that supports the above chart. In addition, the predicted total system purchases for IHDSL are provided for 2012 and 2013. For 2012 and 2013 the system purchases reflect a weather normalized forecast for the full year. In addition, values for 2013 are provided with a 20 year trend assumption for weather normalization.

Table 3-6: Total System Purchases			
Year	**Actual**	**Predicted**	**% Difference**
Purchased Energy (GWh)			
2002	230.0	231.4	0.6%
2003	234.5	234.1	(0.2%)
2004	234.4	232.7	(0.7%)
2005	242.7	243.4	0.3%
2006	234.4	234.1	(0.1%)
2007	241.2	242.0	0.3%
2008	245.6	243.4	(0.9%)
2009	247.2	246.7	(0.2%)
2010	250.2	247.8	(1.0%)
2011	246.8	251.4	1.9%
2012 Weather Normal		**254.0**	
2013 Weather Normal		**256.2**	
2013 Weather Normal - 20 year trend		**256.1**	

The weather normalized amount for 2013 is determined by using 2013 dependent variables in the prediction formula on a monthly basis together with the average monthly heating degree days and cooling degree days that occurred from January 2002 to December 2011 (i.e. ten years). The 2013 weather normalized 20 year trend value reflects the trend in monthly heating degree days and cooling degree days that occurred from January 1992 to December 2011.

The weather normal ten year average has been used as the purchased forecast in this Application for the purposes of determining a billed kWh load forecast which is used to design rates. The ten year average has been used as this is consistent with the period of time over which the regression analysis was conducted

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. This adjustment has been made by IHDSL using the average loss factor from 2002 to 2011 of 1.0863. With this average loss factor the total weather normalized billed energy will be 233.8 GWh for 2012 (i.e.

254.0/1.0863) and 235.8 GWh for 2013 (i.e. 256.2/1.0863) before adjustments for 2012 and 2013 CDM programs and the elimination of Hydro One load Transfers in 2013.

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 3-7: Historical Customer/Connection Data

Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Total
Number of Customers/Connections							
2002	12,075	837	71	2,107	177	0	15,267
2003	12,299	852	72	2,196	181	0	15,600
2004	12,539	886	73	2,309	183	0	15,990
2005	12,748	907	72	2,371	189	0	16,287
2006	12,867	797	80	2,371	189	90	16,394
2007	12,991	819	71	2,489	186	89	16,645
2008	13,277	836	73	2,588	186	84	17,044
2009	13,533	855	72	2,625	193	83	17,361
2010	13,651	865	68	2,685	201	82	17,552
2011	13,779	896	67	2,728	225	81	17,776

From the historical customer/connection data the growth rates in customers/ connections can be evaluated. The growth rates are provided in the following table. The geometric mean growth rate in number of customers is also provided. The geometric mean approach provides the average compounding growth rate from 2002 to 2011. With regards to the Hydro One load transfers it assumed the number of customers is one on a historical and forecast basis.

Table 3-8: Growth Rate in Customer/Connections						
Year	**Residential**	**GS<50**	**GS>50**	**Street Lighting**	**Sentinels**	**USL**
Growth Rate in Customers/Connections						
2002						
2003	1.9%	1.8%	1.4%	4.2%	2.3%	
2004	2.0%	4.0%	1.4%	5.1%	1.1%	
2005	1.7%	2.4%	(1.4%)	2.7%	3.3%	
2006	0.9%	(12.1%)	11.1%	0.0%	0.0%	
2007	1.0%	2.8%	(11.3%)	5.0%	(1.6%)	(1.1%)
2008	2.2%	2.1%	2.8%	4.0%	0.0%	(5.6%)
2009	1.9%	2.3%	(1.4%)	1.4%	3.8%	(1.2%)
2010	0.9%	1.2%	(5.6%)	2.3%	4.1%	(1.2%)
2011	0.9%	3.6%	(1.5%)	1.6%	11.9%	(1.2%)
Geometric Mean	**1.5%**	**0.8%**	**(0.6%)**	**2.9%**	**2.7%**	**(2.1%)**

The resulting geometric mean was first applied to the 2011 customer/connection numbers to determine the forecast of customer/connections in 2012 and 2013. The following table outlines the forecast of customers and connections by rate class.

Table 3-9: Customer/Connection Forecast							
Year	**Residential**	**GS<50**	**GS>50**	**Street Lighting**	**Sentinels**	**USL**	**Total**
Forecast Number of Customers/Connections							
2012	**13,983**	**903**	**67**	**2,807**	**231**	**79**	**18,070**
2013	**14,189**	**910**	**66**	**2,889**	**237**	**78**	**18,369**

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 2002 to 2011.

Table 3-10: Historical Annual Usage per Customer							
Year	**Residential**	**GS<50**	**GS>50**	**Street Lighting**	**Sentinels**	**USL**	**Hydro One Load Transfers**
Annual kWh Usage Per Customer/Connection							
2002	11,485	26,625	547,243	556	748	0	1,102,714
2003	11,983	29,293	538,389	431	752	0	1,654,070
2004	11,866	30,395	497,310	536	739	0	1,240,553
2005	12,144	31,204	553,123	617	697	0	1,459,018
2006	11,588	34,117	497,886	610	698	3,242	1,386,067
2007	11,446	34,754	553,811	601	679	5,839	1,135,841
2008	11,295	33,971	620,129	593	668	6,050	1,040,153
2009	11,112	32,881	659,351	601	632	5,948	981,975
2010	10,867	33,744	751,894	588	581	6,020	1,001,807
2011	10,893	34,095	745,100	534	490	6,041	951,716

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed. That information is provided in the following table. The geometric mean growth rate has also been shown.

Table 3-11: Growth Rate in Usage Per Customer/Connection

Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Hydro One Load Transfers
Growth Rate in Customer/Connection							
2002							
2003	4.3%	10.0%	(1.6%)	(22.5%)	0.4%		50.0%
2004	(1.0%)	3.8%	(7.6%)	24.5%	(1.6%)		(25.0%)
2005	2.3%	2.7%	11.2%	15.0%	(5.8%)		17.6%
2006	(4.6%)	9.3%	(10.0%)	(1.2%)	0.2%		(5.0%)
2007	(1.2%)	1.9%	11.2%	(1.4%)	(2.6%)	80.1%	(18.1%)
2008	(1.3%)	(2.3%)	12.0%	(1.4%)	(1.7%)	3.6%	(8.4%)
2009	(1.6%)	(3.2%)	6.3%	1.4%	(5.3%)	(1.7%)	(5.6%)
2010	(2.2%)	2.6%	14.0%	(2.0%)	(8.2%)	1.2%	2.0%
2011	0.2%	1.0%	(0.9%)	(9.2%)	(15.6%)	0.3%	(5.0%)
Geometric Mean	**(0.6%)**	**2.8%**	**3.5%**	**(0.4%)**	**(4.6%)**	**13.3%**	**(1.6%)**

For the forecast of usage per customer/connection the historical geometric mean was applied to the 2011 usage and the resulting usage forecast is as follows:

Table 3-12: Forecast Annual kWh Usage per Customer/Connection

Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Hydro One Load Transfers
Forecast Annual kWh Usage per Customers/Connection							
2012	**10,829**	**35,044**	**771,094**	**532**	**467**	**6,842**	**936,271**
2013	**10,766**	**36,021**	**797,994**	**529**	**446**	**7,749**	**921,076**

With the preceding information the non-normalized weather billed energy forecast can be determined by applying the forecast numbers of customers/connections from Table 3-9 by the forecast of annual usage per customer/connection from Table 3-12. T he resulting non-normalized weather billed energy forecast is shown in the following table.

Table 3-13: Non-normalized Weather Billed Energy Forecast

Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Hydro One Load Transfers	Total
NON-normalized Weather Billed Energy Forecast (GWh)								
2012 (Not Normalized)	**151.4**	**31.6**	**51.3**	**1.5**	**0.1**	**0.5**	**0.9**	**237.5**
2013 (Not Normalized)	**152.8**	**32.8**	**52.8**	**1.5**	**0.1**	**0.6**	**0.9**	**241.5**

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 233.8 GWh for 2012 and 235.8 GWh for 2013 before adjustments for 2012 and 2013 CDM programs and the elimination of Hydro One load transfers in 2013.

The difference between the non-normalized and normalized forecast adjustments is (3.6) GWh in 2012 (i.e. 233.8 – 237.4) and (5.6) GWh in 2013 (i.e. 235.8 – 241.5). The difference is assumed to be associated with moving the forecast from a non-normalized to a weather normal basis and this amount will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One for IHDSL for the cost allocation study, which has been used to support this Application, it was determined that the weather sensitivity by rate classes is as follows:

Table 3-14: Weather Sensitivity by Rate Class

Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Hydro One Load Transfers
Weather Sensitivity						
82.5%	82.5%	65.0%	0.0%	0.0%	0.0%	0.0%

For the GS > 50 kW class the weather sensitivity amount of 65% was provided in the weather normalization work completed by Hydro One. For the Residential and General Service < 50 kW classes, it is has been assumed in previous cost of service applications that these two classes are 100% weather sensitive. Intervenors expressed concern with this assumption and have suggested that 100% weather sensitivity is not appropriate. IHDSL agrees with this position but also submits that the weather sensitivity for the Residential and GS < 50 kW classes should be higher than the GS > 50 kW class. As a result, IHDSL has assumed the weather sensitivity for the Residential and General Service < 50 kW classes to be mid-way between 100% and 65%, or 82.5%.

The difference between the non-normalized and normalized forecast of (3.6) GWh in 2012 and (5.6) GWh in 2013 has been assigned on a *pro rata* basis to each rate class based on the above level of weather sensitivity.

A manual adjustment has been made to the volumes associated with Hydro One load transfers as it is expected these load transfer will be eliminated in 2013.

In addition a manual adjustment has been made to reflect the impact of 2012 and 2013 CDM programs on the load forecast. This adjustment reflects the "gross" impact of 2012 and 2013 CDM programs on the load forecast. The gross impact includes the net results measured by the OPA plus an estimate of the average net to gross adjustment reflecting gross and net savings information provided in the OPA 2006-2010 Final CDM Results. The net results provide a measurement of the program effectiveness used to achieve the LDC targets. The gross results include the net results plus the estimated impact of customers participating in a program even if an incentive was not provided to participate. In the past this has been termed the level of "free ridership". In other words, the gross results include the results from those who participated in the program because there was an incentive plus those who participated even if there was not an incentive. In IHDSL's view it is the gross level that impacts the load forecast.

The following table outlines the average net to gross factor of 66.9% based on information provided in the OPA 2006-2010 Final CDM Results for IHDSL;

Table 3-15: Average Net to Gross Percentage

	OPA 2006-2010 Final CDM Results (Gross)	OPA 2006-2010 Final CDM Results (Net)	# Difference	% Difference of Net
2006	1,644,593	1,472,589	172,004	11.7%
2007	4,964,101	2,455,329	2,508,772	102.2%
2008	5,013,598	3,143,863	1,869,735	59.5%
2009	7,236,399	4,589,194	2,647,205	57.7%
2010	6,830,132	4,029,540	2,800,593	69.5%
2011	6,668,005	3,859,190	2,808,815	72.8%
2012	6,394,406	3,742,776	2,651,631	70.8%
2013	6,307,311	3,698,822	2,608,489	70.5%
Total	45,058,546	26,991,303	18,067,243	66.9%

IHDSL currently has available preliminary actual results from 2011 programs that contribute to the four year licensed CDM kWh targets of 9,200,000 assigned to IHDSL. The 2011 preliminary actual results are based on the fourth quarter 2011 CDM Status Report provided to IHDSL by the OPA. With having knowledge of the 2011 results this impacts on the level of savings needed from 2012 to 2014 programs in order to achieve the licensed 4 year CDM target. Based on the following table the 2011 preliminary actual savings will contribute 25.8% to the four year target. The table indicates that assuming persistence, 2012 to 2014 programs will need to achieve 12.4% of the four year target each year in order to achieve the target.

Table 3-16: Schedule to Achieve 4 Year kWh CDM Target

4 Year 2011 to 2014 kWh target					
9,200,000					
	2011	2012	2013	2014	Total
2011 Programs	6.4%	6.4%	6.4%	6.4%	25.8%
2012 Programs		12.4%	12.4%	12.4%	37.1%
2013 Programs			12.4%	12.4%	24.7%
2014 Programs				12.4%	12.4%
	6.4%	18.8%	31.2%	43.6%	100.0%
kWh					
2011 Programs	592,454	592,454	592,454	592,454	2,369,815
2012 Programs		1,138,364	1,138,364	1,138,364	3,415,093
2013 Programs			1,138,364	1,138,364	2,276,728
2014 Programs				1,138,364	1,138,364
	592,454	1,730,818	2,869,182	4,007,546	9,200,000

The above table suggests that in 2012, the savings from 2012 programs will be 1,138,364 kWh on a net basis. However on a gross basis this amount would be 1,138,364 times 1.669 (i.e. the net to gross factor determined in table 3-15) or 1,900,354 kWh. In IHDSL's view, the 2012 load forecast should be adjusted by 1,900,354 kWh to reflect CDM savings from 2012 programs.

The above table also suggest that in 2013, the savings from 2012 and 2013 programs will be a 1,138,364 kWh times two or 2,276,728 kWh on a net basis. However on a gross basis this amount would be 2,276,728 times 1.669 (i.e. the net to gross factor determined in table 3-15) or 3,800,708 kWh. In IHDSL's view, the 2013 load forecast should be adjusted by 3,800,708 kWh to reflect CDM savings from 2012 and 2013 programs.

In accordance with the Guidelines for Electricity Distributor Conservation and Demand Management [EB-2012-0003], issued April 26, 2012, it is IHDSL's understanding that as part of this application expected CDM savings in 2013 from 2011, 2012 and 2013 programs will need to be established for LRAM variance accounts purposes. It is also IHDSL's understanding that the OPA will measure CDM results attributable to the four year targets on a net basis. Consistent with past practices, it is expected the net level of savings will be used for LRAM calculations. As a result, it is IHDSL's view the units used for the 2013 LRAM variance account should also be on a net basis. Based on the net information in table 3-16, IHDSL expects to achieve 2,869,182 net kWh savings in 2013 from 2011 to 2013 CDM programs. For LRAM variance account purposes, the following table outlines how this expected savings has been allocated to rate class using the 2013 information from table 3-13 excluding Hydro One load transfers. The expected kW saving has also been provided for those classes billed distribution charges on a kW basis using the average kW/KWh factors from Table 3-20

Table 3-17: 2013 Expected Savings for LRAM Variance Account

	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Total
kWh	1,822,097	390,836	629,564	18,246	1,262	7,177	2,869,182
kW where applicable			1,811	53	3.5		1,868

The following table outlines how the classes have been adjusted to align the non-normalized forecast with the normalized forecast and reflect the adjustments discussed above.

Table 3-18: Alignment of Non-normal to Weather Normal Forecast

Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Hydro One Load Transfers	Total
Non-normalized Weather Billed Energy Forecast (GWh)								
2012 Non-Normalized Bridge	151.4	31.6	51.3	1.5	0.1	0.5	0.9	237.5
2013 Non-Normalized Test	152.8	32.8	52.8	1.5	0.1	0.6	0.9	241.5
Weather Adjustment (GWh)								
2012	(2.5)	(0.5)	(0.7)	0.0	0.0	0.0	0.0	(3.6)
2013	(3.8)	(0.8)	(1.0)	0.0	0.0	0.0	0.0	(5.6)
Hydro One Load Tranfer Adjustment (GWh)								
2012								
2013							(0.9)	(0.9)
CDM Adjustment (GWh)								
2012	(1.2)	(0.3)	(0.4)	(0.0)	(0.0)	(0.0)	0.0	(1.9)
2013	(2.4)	(0.5)	(0.8)	(0.0)	(0.0)	(0.0)	0.0	(3.8)
Weather Normalized Billed Energy Forecast (GWh)								
2012 Normalized Bridge	147.7	30.9	50.3	1.5	0.1	0.5	0.9	231.9
2013 Normalized Test	146.6	31.4	50.9	1.5	0.1	0.6	0.0	231.1

Billed KW Load Forecast

There are three rate classes that charge volumetric distribution on per kW basis. These include GS > 50 kW, Street lighting and Sentinels. 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 kWh 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 3-19: Historical Annual kW per Applicable Rate Class

Year	GS>50	Street Lighting	Sentinels	Total
Billed Annual kW				
2002	88,878	3,255	368	92,500
2003	118,748	3,639	378	122,765
2004	112,828	3,745	376	116,949
2005	115,611	3,909	365	119,885
2006	118,310	4,014	367	122,691
2007	116,956	4,153	351	121,460
2008	134,693	4,261	345	139,299
2009	136,122	4,370	339	140,832
2010	144,502	4,389	324	149,215
2011	139,425	4,416	306	144,148

The following table illustrates the historical ratio of kW/kWh as well as the average ratio for 2002 to 2011.

Table 3-20: Historical kW/KWh Ratio per Applicable Rate Class

Year	GS>50	Street Lighting	Sentinels
Ratio of kW to kWh			
2002	0.2287%	0.2777%	0.2777%
2003	0.3063%	0.3844%	0.2779%
2004	0.3108%	0.3023%	0.2778%
2005	0.2903%	0.2672%	0.2774%
2006	0.2970%	0.2777%	0.2783%
2007	0.2974%	0.2776%	0.2778%
2008	0.2975%	0.2778%	0.2778%
2009	0.2867%	0.2771%	0.2778%
2010	0.2826%	0.2778%	0.2778%
2011	0.2793%	0.3030%	0.2779%
Average 2002 to 2011	**0.2877%**	**0.2923%**	**0.2778%**

The average ratio was applied to the weather normalized billed energy forecast in Table 3-18 to provide the forecast of kW by rate class as shown below. The following table outlines the forecast of kW for the applicable rate classes.

Table 3-21: kW Forecast by Applicable Rate Class

Year	GS>50	Street Lighting	Sentinels	Total
Predicted Billed kW				
2012 Normalized Bridge	**144,598**	**4,329**	**298**	**149,224**
2013 Normalized Test	**146,480**	**4,400**	**289**	**151,169**

Table 3-22 provides a summary of the billing determinants by rate class that are used to develop the proposed rates.

Table 3-22: Summary of Forecast						
	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Weather Normalized Bridge	2013 Weather Normalized Test
ACTUAL AND PREDICTED KWH PURCHASES						
Actual kWh Purchases		247,239,189	250,239,379	246,758,167		
Predicted kWh Purchases		246,672,820	247,841,894	251,420,561	254,027,868	256,194,558
% Difference of actual and predicted purchases		(0.2%)	(1.0%)	1.9%		
BILLING DETERMINANTS BY CLASS						
Residential						
Customers	13,512	13,533	13,651	13,779	13,983	14,189
kWh	153,846,698	150,373,777	148,340,356	150,098,110	147,749,853	146,562,898
GS<50						
Customers	827	855	865	896	903	910
kWh	31,019,894	28,113,433	29,188,874	30,548,695	30,870,769	31,437,455
GS>50						
Customers	72	72	68	67	67	66
kWh	39,978,179	47,473,258	51,128,771	49,921,685	50,262,876	50,917,130
kW	115,534	136,122	144,502	139,425	144,598	146,480
Sentinels						
Connections	193	193	201	225	231	237
kWh	123,512	122,021	116,703	110,241	107,147	104,161
kW	344	339	324	306	298	289
Street Lighting						
Connections	2,810	2,625	2,685	2,728	2,807	2,889
kWh	1,652,371	1,576,912	1,580,058	1,457,369	1,481,108	1,505,545
kW	4,924	4,370	4,389	4,416	4,329	4,400
USL						
Connections	85	83	82	81	79	78
kWh	562,039	493,680	493,680	489,312	538,257	592,220
Hydro One Load Transfers		981,975	1,001,807	951,716	936,271	0
kWh						
Customer/Connections	17,499	17,361	17,552	17,776	18,070	18,369
kWh	227,182,693	229,135,056	231,850,249	233,577,129	231,946,281	231,119,409
kW from applicable classes	120,802	140,832	149,215	144,148	149,224	151,169

APPENDIX A

MONTHLY DATA USED FOR REGRESSION ANALYSISAppendix 3-A

	Purchased	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Spring Fall Flag	Number of Customers - 3 Main Classes	Predicted Purchases
Jan-02	22,119,629	572.2	0.0	31	0	12,928	22,619,260
Feb-02	20,006,640	540.2	0.0	28	0	12,847	20,307,820
Mar-02	20,650,604	545.6	0.0	31	1	12,951	21,248,800
Apr-02	17,267,599	329.5	8.3	30	1	12,956	17,878,454
May-02	17,046,489	227.5	7.8	31	1	12,956	17,035,297
Jun-02	16,519,857	36.2	70.0	30	0	12,983	16,557,894
Jul-02	19,592,994	0.0	192.4	31	0	13,015	20,086,221
Aug-02	18,262,722	0.2	142.7	31	0	13,031	18,722,929
Sep-02	16,184,889	21.8	87.6	30	1	13,047	15,890,762
Oct-02	18,054,189	292.2	10.0	31	1	13,084	18,134,354
Nov-02	20,152,102	445.0	0.0	30	1	13,106	19,417,027
Dec-02	24,095,090	619.4	0.0	31	0	13,141	23,503,112
Jan-03	26,337,081	814.5	0.0	31	0	13,161	26,244,939
Feb-03	23,542,374	699.0	0.0	28	0	13,181	22,876,106
Mar-03	22,443,297	581.1	0.0	31	1	13,194	22,001,279
Apr-03	18,675,852	372.5	2.4	30	1	13,214	18,587,229
May-03	16,161,438	177.9	0.0	31	1	13,225	16,411,560
Jun-03	16,030,617	43.4	52.9	30	0	13,223	16,436,704
Jul-03	17,815,329	0.2	118.3	31	0	13,244	18,269,591
Aug-03	17,334,894	2.0	128.0	31	0	13,264	18,585,807
Sep-03	15,290,001	54.9	24.0	30	1	13,286	14,835,700
Oct-03	17,925,927	276.0	0.0	31	1	13,327	17,887,610
Nov-03	19,568,559	398.5	0.0	30	1	13,340	19,016,494
Dec-03	23,355,427	561.5	0.0	31	0	13,362	22,929,836
Jan-04	27,645,690	849.1	0.0	31	0	13,405	26,985,928
Feb-04	22,842,144	631.7	0.0	29	0	13,415	22,778,652
Mar-04	21,475,552	487.3	0.0	31	1	13,436	20,949,631
Apr-04	17,912,215	331.5	0.0	30	1	13,455	18,204,023
May-04	16,456,492	158.9	8.6	31	1	13,471	16,646,541
Jun-04	15,766,963	44.2	31.6	30	0	13,498	16,146,471
Jul-04	17,509,022	3.6	86.4	31	0	13,510	17,711,107
Aug-04	17,156,978	12.8	59.6	31	0	13,525	17,109,511
Sep-04	16,118,218	30.0	41.2	30	1	13,556	15,253,151
Oct-04	17,179,546	226.3	1.5	31	1	13,575	17,499,027
Nov-04	19,264,875	379.1	0.0	30	1	13,609	19,030,947
Dec-04	25,084,905	643.4	0.0	31	0	13,632	24,357,961
Jan-05	27,046,364	770.0	0.0	31	0	13,643	26,135,032
Feb-05	22,591,240	616.4	0.0	28	0	13,652	22,223,246
Mar-05	22,726,877	608.6	0.0	31	1	13,665	22,883,747
Apr-05	17,649,091	306.8	0.0	30	1	13,678	18,095,834
May-05	16,489,823	189.4	0.8	31	1	13,691	17,087,875
Jun-05	18,724,232	8.9	146.3	30	0	13,727	19,088,650
Jul-05	20,388,288	0.0	188.7	31	0	13,742	20,753,454
Aug-05	18,992,000	0.2	140.7	31	0	13,774	19,454,419
Sep-05	16,294,845	22.6	52.1	30	1	13,777	15,687,410
Oct-05	17,508,333	220.2	7.6	31	1	13,783	17,804,070
Nov-05	19,503,983	388.4	0.0	30	1	13,782	19,343,913
Dec-05	24,772,252	665.3	0.0	31	0	13,793	24,833,919

	Purchased	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Spring Fall Flag	Number of Customers - 3 Main Classes	Predicted Purchases
Jan-06	23,275,097	551.8	0.0	31	0	13,803	23,261,773
Feb-06	21,949,173	604.3	0.0	28	0	13,808	22,219,782
Mar-06	22,008,625	516.6	0.0	31	1	13,817	21,761,852
Apr-06	17,506,649	293.3	0.0	30	1	13,833	18,071,788
May-06	16,720,482	136.9	26.0	31	1	13,832	17,206,404
Jun-06	17,643,645	19.5	73.6	30	0	13,744	17,231,409
Jul-06	20,377,985	0.0	167.3	31	0	13,764	20,181,250
Aug-06	18,444,801	4.2	101.6	31	0	13,786	18,434,852
Sep-06	15,835,529	80.9	12.9	30	1	13,796	15,429,681
Oct-06	18,304,414	288.3	1.1	31	1	13,814	18,605,676
Nov-06	19,538,671	382.2	0.0	30	1	13,635	19,101,721
Dec-06	22,793,828	500.5	0.0	31	0	13,832	22,577,126
Jan-07	24,279,310	647.1	0.0	31	0	13,849	24,639,450
Feb-07	23,881,688	740.1	0.0	28	0	13,861	24,169,641
Mar-07	22,297,190	546.7	0.0	31	1	13,865	22,232,444
Apr-07	18,569,417	356.4	0.0	30	1	13,869	18,989,847
May-07	16,382,762	136.4	22.4	31	1	13,873	17,142,688
Jun-07	17,880,105	16.5	99.2	30	0	13,881	18,047,100
Jul-07	18,476,520	3.2	106.1	31	0	13,905	18,672,201
Aug-07	19,239,334	5.2	141.0	31	0	13,925	19,692,463
Sep-07	16,489,843	36.9	47.5	30	1	13,949	15,941,034
Oct-07	17,241,375	137.7	19.8	31	1	13,987	17,209,238
Nov-07	20,822,608	462.5	0.0	30	1	14,001	20,609,237
Dec-07	25,594,484	630.7	0.0	31	0	14,035	24,607,805
Jan-08	25,337,708	623.5	0.0	31	0	14,052	24,525,412
Feb-08	23,919,251	674.7	0.0	29	0	14,069	24,071,137
Mar-08	23,324,392	610.2	0.0	31	1	14,091	23,357,369
Apr-08	17,845,473	253.9	0.0	30	1	14,109	17,814,760
May-08	17,203,595	193.5	2.5	31	1	14,151	17,679,686
Jun-08	17,657,148	22.7	71.5	30	0	14,186	17,685,855
Jul-08	19,399,006	1.0	111.0	31	0	14,218	19,109,475
Aug-08	18,496,935	12.7	64.0	31	0	14,260	18,009,227
Sep-08	16,944,225	59.0	26.7	30	1	14,297	16,039,077
Oct-08	18,736,114	278.6	0.0	31	1	14,337	18,993,875
Nov-08	20,914,296	451.6	0.0	30	1	14,348	20,824,855
Dec-08	25,844,885	654.6	0.0	31	0	14,388	25,315,060
Jan-09	27,698,758	830.2	0.0	31	0	14,411	27,788,141
Feb-09	22,854,687	606.4	0.0	28	0	14,426	22,903,784
Mar-09	22,750,704	533.8	0.0	31	1	14,438	22,659,600
Apr-09	18,949,042	305.8	1.2	30	1	14,448	18,931,032
May-09	17,348,781	158.8	6.9	31	1	14,455	17,640,304
Jun-09	17,392,957	49.3	34.2	30	0	14,460	17,309,098
Jul-09	18,006,297	6.2	43.7	31	0	14,710	17,830,422
Aug-09	20,135,392	9.8	91.0	31	0	14,976	19,478,673
Sep-09	17,368,091	55.2	20.9	30	1	15,073	16,646,792
Oct-09	19,458,169	287.8	0.0	31	1	15,110	19,941,095
Nov-09	19,998,430	361.2	0.0	30	1	15,107	20,368,337
Dec-09	25,277,881	631.3	0.0	31	0	14,563	25,175,543

	Purchased	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Spring Fall Flag	Number of Customers - 3 Main Classes	Predicted Purchases
Jan-10	26,451,956	720.0	0.0	31	0	14,554	26,402,916
Feb-10	22,355,018	598.3	0.0	28	0	14,553	22,925,377
Mar-10	21,335,193	422.8	0.0	31	1	14,566	21,247,327
Apr-10	17,366,211	225.1	0.0	30	1	14,576	17,907,895
May-10	18,594,842	107.9	45.7	31	1	14,570	18,132,055
Jun-10	18,232,281	21.7	58.7	30	0	14,584	17,737,364
Jul-10	22,225,962	1.8	164.9	31	0	14,599	21,024,175
Aug-10	21,301,865	2.1	138.8	31	0	14,633	20,338,078
Sep-10	17,785,838	78.1	31.5	30	1	14,646	16,808,731
Oct-10	18,734,173	241.6	0.0	31	1	14,664	18,824,344
Nov-10	20,451,455	405.3	0.0	30	1	14,688	20,539,410
Dec-10	25,404,585	676.2	0.0	31	0	14,707	25,954,222
Jan-11	26,274,474	775.3	0.0	31	0	14,713	27,342,513
Feb-11	22,971,970	654.2	0.0	28	0	14,716	23,877,578
Mar-11	22,951,605	572.8	0.0	31	1	14,728	23,510,679
Apr-11	18,914,567	332.3	0.0	30	1	14,729	19,564,872
May-11	17,615,740	134.1	13.0	31	1	14,733	17,760,132
Jun-11	17,571,916	19.0	52.2	30	0	14,742	17,686,221
Jul-11	22,292,830	0.0	198.5	31	0	14,759	22,103,589
Aug-11	19,354,570	0.0	122.2	31	0	14,772	19,994,115
Sep-11	17,323,768	48.2	39.7	30	1	14,772	16,753,453
Oct-11	18,576,164	235.5	2.4	31	1	14,794	18,943,791
Nov-11	19,598,868	342.1	0.0	30	1	14,809	19,786,285
Dec-11	23,311,694	534.0	0.0	31	0	14,826	24,097,336
Jan-12		715.4	0.0	31	0	14,847	26,648,755
Feb-12		636.5	0.0	29	0	14,868	24,385,324
Mar-12		542.6	0.0	31	1	14,889	23,259,398
Apr-12		310.7	1.2	30	1	14,910	19,488,652
May-12		162.1	13.4	31	1	14,931	18,371,041
Jun-12		28.1	69.0	30	0	14,952	18,504,184
Jul-12		1.6	137.7	31	0	14,970	20,658,061
Aug-12		4.9	113.0	31	0	14,987	20,033,875
Sep-12		48.8	38.4	30	1	15,005	16,972,452
Oct-12		248.4	4.2	31	1	15,023	19,417,748
Nov-12		401.6	0.0	30	1	15,041	20,861,368
Dec-12		611.7	0.0	31	0	15,058	25,427,012
Jan-13		715.4	0.0	31	0	15,076	26,891,621
Feb-13		636.5	0.0	28	0	15,094	24,031,625
Mar-13		542.6	0.0	31	1	15,112	23,495,394
Apr-13		310.7	1.2	30	1	15,129	19,721,213
May-13		162.1	13.4	31	1	15,147	18,600,167
Jun-13		28.1	69.0	30	0	15,165	18,729,875
Jul-13		1.6	137.7	31	0	15,183	20,883,752
Aug-13		4.9	113.0	31	0	15,201	20,259,567
Sep-13		48.8	38.4	30	1	15,218	17,198,143
Oct-13		248.4	4.2	31	1	15,236	19,643,439
Nov-13		401.6	0.0	30	1	15,254	21,087,059
Dec-13		611.7	0.0	31	0	15,272	25,652,703

OPERATING REVENUE VARIANCE ANALYSIS

THROUGHPUT REVENUE and OTHER OPERATING REVENUE

VARIANCE ANALYSIS ON THROUGHPUT REVENUE:

A summary of historical and forecast operating revenues is presented in Table 3.3.1. A variance analysis for the other net operating revenue will be provided further in Tab 3 Schedule 2 of this Exhibit.

2009 Actual:

Table 3.3.1 Comparision 2009 Actual to 2009 Board Approved - Throughput Revenu

Operating Revenue	2009 OEB Approved	2009 Actual	Variance	% Variance to OEB
Distribution Revenue				
Residential	6,011,508	5,660,360	- 351,148	-5.8%
GS<50kW	721,481	652,527	- 68,954	-9.6%
GS>50kW-4,999 kW	735,939	765,550	29,611	4.0%
Sentinel Lights	6,467	11,995	5,528	85.5%
Street Lights	43,398	131,366	87,968	202.7%
Unmetered Scattered Load	44,918	34,771	- 10,147	-22.6%
Total Operating Revenues	7,563,711	7,256,569	- 307,142	-4.1%

Throughput revenue for 2009 was 4.1% lower or $307,25 lower than the amounts approved by the Board in 2009 (EB-2008-0133). The decrease is attributable to decrease in all classes except GS<>50 kW – 4,999 rate classes for both customer connections and usage.

Table 3.3.2 be low compares the 2009 O EB Approved billing quantities to the 2009 A ctual quantities.

Table 3.3.2 Comparison 2009 Actual to 2009 Board Approved Billing Quantities

	Customer Connections			kWh			kW		
Rate Class	2009 OEB Approved	2009 Actual	Variance	2009 OEB Approved	2009 Actual	Variance	2009 OEB Approved	2009 Actual	Variance
Residential	13,512	13,533	21	155,528,870	150,373,777	- 5,155,093			
GS<50kW	827	855	28	31,359,068	28,113,433	- 3,245,635			
GS>50kW-4,999 kW	72	72	-	40,258,708	47,473,258	7,214,550	116,345	136,122	19,777
Streetlights	2,810	2,625	- 185	1,652,371	1,576,912	- 75,459	4,924	4,370	- 554
Unmetered Scattered Load	85	83	- 2	562,039	493,680	- 68,359			
Sentinel Lights	193	193	-	123,512	122,021	- 1,491	344	339	- 5
Total	17,499	17,361	- 138	229,484,568	228,153,081	- 1,331,487	121,613	140,831	19,218

Comparison 2010 Actual to 2009 Actual – Throughput Revenue:

Table 3.3.3 Comparision 2009 Actual to 2010 Actual - Throughput Revenue

Operating Revenue	2009 Actual	2010 Actual	Variance	% Variance to 2009 Act
Distribution Revenue				
Residential	5,660,360	5,797,125	136,765	2.4%
GS<50kW	652,527	602,655	- 49,872	-7.6%
GS>50kW-4,999 kW	765,550	754,396	- 11,154	-1.5%
Sentinel Lights	11,995	19,055	7,060	58.9%
Street Lighrts	131,366	231,528	100,162	76.2%
Unmetered Scattered Load	34,771	41,669	6,898	19.8%
Total Operating Revenues	7,256,569	7,446,428	189,859	2.6%

The 2010 throughput revenue was $189,859 or 2.6% higher than the 2009 actual revenue. The decreased revenue from the general service rate classes is offset by the increase in the street lighting class as the 2nd installment of cost allocation changes as directed by the OEB. Despite load reductions for the residential class, revenue increased for all rate classes due to timing differences between the fiscal and rate year periods, as January 1 2010 to April 30 2010 reflected the full impact of the 2009 EDR rate increase, and IRM adjustments between May 1, 2010 and December 31, 2010.

Table 3.3.4 below compares the 2009 Actual billing quantities to the 2010 Actual quantities.

Table 3.3.4 Comparison 2009 Actual to 2010 Actual Billing Quantities

	Customer Connections			kWh			kW		
Rate Class	2009 Actual	2010 Actual	Variance	2009 Actual	2010 Actual	Variance	2009 Actual	2010 Actual	Variance
Residential	13,533	13,651	118	150,373,777	148,340,356	- 2,033,421			
GS<50kW	855	865	10	28,113,433	29,188,874	1,075,441			
GS>50kW-4,999 kW	72	68	- 4	47,473,258	51,128,771	3,655,513	136,122	144,502	8,380
Streetlights	2,625	2,685	60	1,576,912	1,580,058	3,146	4,370	4,389	19
Unmetered Scattered Load	83	82	- 1	493,680	493,680	-			
Sentinel Lights	193	201	8	122,021	116,703	- 5,318	339	324	- 15
Total	17,361	17,552	191	228,153,081	230,848,442	2,695,361	140,831	149,215	8,384

2011 Actual:

Comparison 2010 Actual to 2011 Actual – Throughput Revenue*:*

Table 3.3.5 Comparision 2010 Actual to 2011 Actual - Throughput Revenue

Operating Revenue	2010 Actual	2011 Actual	Variance	% Variance to 2010 Act
Distribution Revenue				
Residential	5,797,125	5,882,306	85,181	1.5%
GS<50kW	602,655	579,267	- 23,388	-3.9%
GS>50kW-4,999 kW	754,396	661,641	- 92,755	-12.3%
Sentinel Lights	19,055	22,990	3,935	20.7%
Street Lighrts	231,528	305,463	73,935	31.9%
Unmetered Scattered Load	41,669	41,084	- 585	-1.4%
Total Operating Revenues	7,446,428	7,492,751	46,323	0.6%

The 2011 throughput revenue was $46,323 or 0.6% higher than the 2010 actual revenue. The decreased revenue from the general service rate classes is offset by the increase in the street lighting class as the 3rd installment of cost allocation changes as directed by the OEB.

Table 3.3.6 below compares the 2010 Actual billing quantities to the 2011 Actual quantities.

Table 3.3.6 Comparison 2010 Actual to 2011 Actual Billing Quantities

	Customer Connections			kWh			kW		
Rate Class	2010 Actual	2011 Actual	Variance	2010 Actual	2011 Actual	Variance	2010 Actual	2011 Actual	Variance
Residential	13,651	13,779	128	148,340,356	150,098,110	1,757,754			
GS<50kW	865	896	31	29,188,874	30,548,695	1,359,821			
GS>50kW-4,999 kW	68	67	- 1	51,128,771	49,921,685	- 1,207,086	144,502	139,425	- 5,077
Streetlights	2,685	2,728	43	1,580,058	1,457,369	- 122,689	4,389	4,416	27
Unmetered Scattered Load	82	81	- 1	493,680	489,312	- 4,368			
Sentinel Lights	201	225	24	116,703	110,241	- 6,462	324	306	- 18
Total	17,552	17,776	224	230,848,442	232,625,412	1,776,970	149,215	144,147	- 5,068

2012 Bridge Year:

Comparison 2011 Actual to 2012 Bridge Throughput Revenue:

Table 3.3.7 Comparision 2011 Actual to 2012 Bridge - Throughput Revenue

Operating Revenue	2011 Actual	2012 Test	Variance	% Variance to 2011 Act
Distribution Revenue				
Residential	5,882,306	6,187,519	305,213	5.2%
GS<50kW	579,267	637,500	58,233	10.1%
GS>50kW-4,999 kW	661,641	696,500	34,859	5.3%
Sentinel Lights	22,990	29,300	6,310	27.4%
Street Lighrts	305,463	317,200	11,737	3.8%
Unmetered Scattered Load	41,084	43,500	2,416	5.9%
Total Operating Revenues	7,492,751	7,911,519	418,768	5.6%

Total throughput operating revenue is forecast to be 5.6% or $ 418,768 higher than the 2011 amounts due to the load decrease within the residential class being partially offset by the increase loads within the remaining customer classes. 2012 Bridge year also includes the SMIRR rates for the residential and GS>50 customer class ($1.86 and $6.33 respectively) The following table

provides the comparatives of 2011 A ctual billing quantities to 2012 B ridge year billing quantities.

Table 3.3.8 Comparison 2011 Actual to 2012 Bridge Billing Quantities

	Customer Connections			kWh			kW		
Rate Class	2011 Actual	2012 Bridge	Variance	2011 Actual	2012 Bridge	Variance	2011 Actual	2012 Bridge	Variance
Residential	13,779	13,983	204	150,098,110	147,749,853	- 2,348,257			
GS<50kW	896	903	7	30,548,695	30,870,769	322,074			
GS>50kW-4,999 kW	67	67	-	49,921,685	50,262,876	341,191	139,425	144,598	5,173
Streetlights	2,728	2,807	79	1,457,369	1,481,108	23,739	4,416	4,329	- 87
Unmetered Scattered Load	81	79	- 2	489,312	538,257	48,945			
Sentinel Lights	225	231	6	110,241	107,147	- 3,094	306	298	- 8
Total	17,776	18,070	294	232,625,412	231,010,010	- 1,615,402	144,147	149,225	5,078

2013 Test Year:

Comparison of 2012 Bridge Year to 2013 Test Year Throughput Revenue:

Table 3.3.9 Comparision 2012 Bridget to 2013 Test Year - Throughput Revenue

Operating Revenue	2012 Test	2013 Bridge	Variance	% Variance to 2012 Test
Distribution Revenue				
Residential	6,187,519	7,264,921	1,077,402	17.4%
GS<50kW	637,500	627,742	- 9,758	-1.5%
GS>50kW-4,999 kW	696,500	517,993	- 178,507	-25.6%
Sentinel Lights	29,300	34,726	5,426	18.5%
Street Lighrts	317,200	394,465	77,265	24.4%
Unmetered Scattered Load	43,500	22,841	- 20,659	-47.5%
Total Operating Revenues	7,911,519	8,862,688	951,169	12.0%

Total throughput revenue is forecast to be $951,169 or 12.0% higher than the 2012 Bridge year. This variance is due to increased revenue resulting from this rate application.

Table 3.3.8 below compares the 2012 Bridge Year billing quantities to the 2013 Test Year billing quantities.

Table 3.3.8 Comparison 2012 Bridge to 2013 Test Year Billing Quantities

	Customer Connections			kWh			kW		
Rate Class	2012 Bridgel	2013 Test	Variance	2012 Bridgel	2013 Test	Variance	2012 Bridgel	2013 Test	Variance
Residential	13,983	14,189	206	147,749,853	146,562,898	- 1,186,955			
GS<50kW	903	910	7	30,870,769	31,437,455	566,686			
GS>50kW-4,999 kW	67	66	- 1	50,262,876	50,917,130	654,254	144,598	146,480	1,882
Streetlights	2,807	2,889	82	1,481,108	1,505,545	24,437	4,329	4,400	71
Unmetered Scattered Load	79	78	- 1	538,257	592,220	53,963			
Sentinel Lights	231	237	6	107,147	104,161	- 2,986	298	289	- 9
Total	18,070	18,369	299	231,010,010	231,119,409	109,399	149,225	151,169	1,944

TRANSFORMER ALLOWANCE

Innisfil currently provides a Transformer Ownership Allowance Credit of $0.60/kW to those customers that own their own transformer facilities. Innisfil is proposing to maintain this rate for the 2013 Test Year for eligible customers.

VARIANCE ANALYSIS ON OTHER DISTRIBUTION REVENUE

2009 Board Approved to 2013 Test Year – Other Operating Revenue:

Table 3.3.9 below summarizes variance by year by account description.

Table 3.3.9 Other Revenue - 2009 Board Approved to 2013 Test Year

USoA #	USoA Description	2009 Board Approved	2009 Actual	09 Board vs 09 Act	2010 Actual	09 Act vs 10 Act	2011 Actual	10 Act vs 11 Act	Bridge Year	Bridge Year	11 Act vs 12 Bridge	Test Year	12 Bridge vs 13 Test
									2012	2012		2013	
	Reporting Basis	CGAAP	CGAAP		CGAAP		CGAAP		CGAAP	MIFRS		MIFRS	
4235	Specific Service Charges	$ 135,935	$ 142,194	$ 6,259	$ 127,673	-$ 14,521	$ 166,067	$ 38,394	$ 149,670	$ 149,670	-$ 16,397	$ 154,100	$ 4,430
4225	Late Payment Charges	$ 89,542	$ 105,597	$ 16,055	$ 111,120	$ 5,523	$ 104,841	-$ 6,279	$ 110,402	$ 110,402	$ 5,561	$ 113,700	$ 3,298
4082	Retail Services Revenues	$ 26,269	$ 35,349	$ 9,080	$ 42,813	$ 7,464	$ 78,272	$ 35,459	$ 54,203	$ 54,203	-$ 24,069	$ 55,033	$ 830
4210	Pole Rental	$ 145,208	$ 154,992	$ 9,784	$ 161,381	$ 6,389	$ 157,442	-$ 3,939	$ 162,676	$ 162,676	$ 5,234	$ 167,600	$ 4,924
4305	Regulatory Debit		$ -	$ -	$ -	$ -	$ -	$ -	-$ 639,864	-$ 639,864	-$ 639,864	$ -	$ 639,864
4325	Special Purpose Chg Reco			$ -	$ 49,901	$ 49,901		-$ 49,901			$ -		$ -
4355	Gain(Loss) on Disposal		$ 33,840	$ 33,840	$ -	-$ 33,840	-$ 126,618	-$ 126,618	-$ 51,476	-$ 51,476	$ 75,142	-$ 48,825	$ 2,651
4375	Misc Non-Utility Income	$ 169,431	$ 377,961	$ 208,530	$ 287,996	-$ 89,965	$ 279,583	-$ 8,413	$ 384,806	$ 384,806	$ 105,223	$ 500,668	$ 115,862
4380	Misc Non-Utility Expense	-$ 169,431	-$ 331,366	-$ 161,935	-$ 389,430	-$ 58,064	-$ 268,700	$ 120,730	-$ 405,862	-$ 405,862	-$ 137,162	-$ 469,228	-$ 63,366
4390	Misc Non-Utility Income	$ 7,053	$ 9,629	$ 2,576	$ 52,823	$ 43,194	$ 24,952	-$ 27,871	$ 30,009	$ 30,009	$ 5,057	$ 30,900	$ 891
4405	Interest Income	$ 34,300	$ 23,617	-$ 10,683	$ 36,839	$ 13,222	$ 53,328	$ 16,489	$ 14,600	$ 14,600	-$ 38,728	$ 3,000	-$ 11,600
4406	SRED Revenue		$ -	$ -	$ -	$ -	$ 153,377	$ 153,377	$ 50,000	$ 50,000	-$ 103,377	$ 50,000	$ -
Specific Service Charges		$ 135,935	$ 142,194	$ 6,259	$ 127,673	-$ 14,521	$ 166,067	$ 38,394	$ 149,670	$ 149,670	-$ 16,397	$ 154,100	$ 4,430
Late Payment Charges		$ 89,542	$ 105,597	$ 16,055	$ 111,120	$ 5,523	$ 104,841	-$ 6,279	$ 110,402	$ 110,402	$ 5,561	$ 113,700	$ 3,298
Other Operating Revenues		$ 171,477	$ 190,341	$ 18,864	$ 204,194	$ 13,853	$ 235,714	$ 31,520	$ 216,879	$ 216,879	-$ 18,835	$ 222,633	$ 5,754
Other Income or Deductions		$ 41,353	$ 113,681	$ 72,328	$ 38,129	-$ 75,552	$ 115,922	$ 77,793	-$ 617,787	-$ 617,787	-$ 733,709	$ 66,515	$ 684,302
Total		$ 438,307	$ 551,813	$ 113,506	$ 481,116	-$ 70,697	$ 622,544	$ 141,428	-$ 140,836	-$ 140,836	-$ 763,380	$ 556,948	$ 697,784

The following analysis by year is provided by account variances in excess of $50,000.

2009 Actual Comparison to 2009 Board Approved – Other Operating Revenue

Account 4375 and 4380 reflect variances $208k and ($161K) respectively due to the higher than anticipated OPA revenue and related expenses for 2009.

2010 Actual Comparison to 2009 Actual – Other Operating Revenue

Account 4375 and 4380 reflect variances of ($90k) and ($58K) respectively due to lower OPA revenue. A ccount 4380 i ncreased due to Innisfil reflecting the unreimbursed cost of the Comverg thermostats.

2011 Actual Comparison to 2010 Actual – Other Operating Revenue:

Account 4355 reflects the loss on disposal of fixed assets within Innisfil financial records. Thru the componentization project, Innisfil is able to identify assets and track distribution assets that are being disposed of.

Account 4380 reflects a normalized year of OPA expenses while 2010 had an unusual transaction of the Comverg thermostat issue.

Account 4406 reflects the first filing Innisfil has done and received for Scientific Research Expenditure and Development (SRED) for the years 2009 and 2010. Innisfil is forecasting to file SRED claims on an annual basis.

2012 Bridge Year Comparison to 2011 Actual – Other Operating Revenue:

Account 4305 is the 2012 regulatory entry required by the OEB for the excess depreciation collected from customers based on the longer useful lives effective 2012.

Account 4375 and 4380 reflect variances $105k and ($137K) respectively due to billing water and waste water for the Town of Innisfil effective August 2012.

Account 4406 reflects a variance of ($103k) due to 2012 Bridge forecasting 1 years' worth of a SRED claim.

Comparison to 2013 Test Year to 2012 Bridge Year– Other Operating Revenue:

Account 4305 variance of $640k due to the onetime adjustment for excess depreciation done in 2012.

Account 4375 and 4380 reflect variances $115k and ($63K) respectively due to billing water and waste water for the Town of Innisfil for a full year as while 2012 reflects on 4 months.

Exhibit	Tab	Schedule	Appendix	Contents
4 – Operating Costs				
	1			**Overview**
		1		Manager's Summary of Operating Costs
	2			**OM&A Costs**
		1		Departmental and Corporate OM&A Activities
		2		OM&A Detailed Costs Tables
		3		Variance Analysis on OM&A Costs
		4		Employee Compensation
		5		Purchase of Products and Services from Non-Affiliates
		6		Depreciation, Amortization and Depletion
	3			**Income Tax, Large Corporation Tax**
		1		Tax Calculations
		2		Capital Cost Allowance (CCA)
	4			**MIFRS Conversion**
		1		MIFRS Impact on OM&A
		2		MIFRS Impact on Depreciation
		3		MIFRS Impact on Tax Calculations
				Appendices
			A	IHDSL Purchasing Policy
			B	2011 Federal & Ontario Tax Returns

OVERVIEW:

MANAGER'S SUMMARY OF OPERATING COSTS

The operating costs presented in this Exhibit represent the annual expenditures required to sustain IHDSL's distribution operations. IHDSL follows the OEB's Accounting Procedures Handbook (the "APH") in distinguishing work performed between operations and maintenance. Historically IHDSL has followed the Canadian Generally Accepted Accounting Principles (CGAAP) in preparation of its financial statements. As stated through this application, IHDSL will be converting to International Financial Reporting Standards (IFRS) in 2013 and has prepared this application under modified IFRS. For clarity and ease of comparison to historical data, this Exhibit first presents all information including the 2012 Bridge year and 2013 Test year under CGAAP. As IHDSL's capitalization policy has not changed there are no changes in OM&A expenses as a result of the transition to IFRS from CGAAP.

IHDSL has not included any one-time or non-regulatory expenses in the 2012 Bridge year and 2013 test year. In IHDSL's audited financial statements the years 2009, 2010 and 2011 included charitable contributions.

In order to provide a useful comparison to historical data these non-regulatory expenses have been removed from OM&A as illustrated in Tables 4.2 – 4.6.

A summary of IHDSL's operating costs for 2009 Board Approved, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and the 2013 Test Year (CGAAP) and 2013 Test Year (IFRS) , is provided in Table 4.1 below. A summary of the variances as required by the Filing Requirements is provided in Tables 4.2 through 4.6.

Table 4.1 Summary of OM&A Expenses:

Table 4.1 Summary of OMA&A Expenses

Description	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Operations	778,575	694,259	870,153	947,441	1,159,195	1,423,862
Maintenance	657,080	544,762	436,208	528,873	601,800	713,650
Billing & Collections	1,010,600	970,447	922,744	925,296	955,500	1,106,020
Community Relations	11,700	10,826	9,114	17,892	18,400	23,900
Aministrative General Expense	1,439,785	1,476,117	1,620,369	1,776,253	1,899,865	2,197,640
Total OM&A	**3,897,740**	**3,696,411**	**3,858,588**	**4,195,755**	**4,634,760**	**5,465,072**
Total Recoverable OM&A	**3,897,740**	**3,696,411**	**3,858,588**	**4,195,755**	**4,634,760**	**5,465,072**
Year Over Year Variance $	**-**	**201,329**	**162,177**	**337,167**	**439,005**	**830,312**
Year Over Year Variance %		**-5%**	**4%**	**9%**	**10%**	**18%**

IHDSL is proposing recovery of 2013 Test Year OM&A costs, excluding amortization, PILs and Interest, totaling **$5,466,072.** Although a 17.9% increase from the 2012 Bridge year, IHDSL is of the view that the costs are valid and are instrumental to maintain our infrastructure, service levels for our customers and provide adequate support for specific employee positions.

IHDSL must invest to be in position to manage in a cost effective manner. To ensure this position IHDSL has the following cost drivers for this Cost of Service Application;

- Requirement of 4.5 FTE's in 2013
- Implementation of an Asset Management Maintenance Program
- Increase in general expenses related to IHDSL's Head Office and Operations Centre

IHDSL will provide further details as to these costs drivers throughout this Exhibit.

A summary of the Recoverable OM&A variance as required by the Filing Requirements is provided in Tables 4.2 and 4.3. As noted above, no changes to the OM&A expenses are made on the transition from GCAAP to MIFRS.

Table 4.2 Summary of Recoverable OM&A Expenses 2009 Board Approved to 2013

	Last Rebasing Year (2009 BA)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
Operations	$ 778,575	$ 694,259	$ 870,153	$ 947,441	$ 1,159,195	$ 1,423,862
Maintenance	$ 657,080	$ 544,762	$ 436,208	$ 528,873	$ 601,800	$ 713,650
SubTotal	**$ 1,435,655**	**$ 1,239,021**	**$ 1,306,361**	**$ 1,476,314**	**$ 1,760,995**	**$ 2,137,512**
%Change (year over year)			5.4%	13.0%	19.3%	21.4%
%Change (Test Year vs Last Rebasing Year - Actual)						72.5%
Billing and Collecting	$ 1,010,600	$ 970,447	$ 922,744	$ 925,296	$ 955,500	$ 1,106,020
Community Relations	$ 11,700	$ 10,826	$ 9,114	$ 17,892	$ 18,400	$ 23,900
Administrative and General	$ 1,439,785	$ 1,476,117	$ 1,620,369	$ 1,776,253	$ 1,899,865	$ 2,197,640
SubTotal	**$ 2,462,085**	**$ 2,457,390**	**$ 2,552,227**	**$ 2,719,441**	**$ 2,873,765**	**$ 3,327,560**
%Change (year over year)			3.9%	6.6%	5.7%	15.8%
%Change (Test Year vs Last Rebasing Year - Actual)						35.4%
Total	**$ 3,897,740**	**$ 3,696,411**	**$ 3,858,588**	**$ 4,195,755**	**$ 4,634,760**	**$ 5,465,072**
%Change (year over year)			4.4%	8.7%	10.5%	17.9%

Table 4.3 Summary OM&A Expense Variances 2009 Board Approved to 2013 Test

	Last Rebasing Year (2009 BA)	Last Rebasing Year (2009 Actuals)	Variance 2009 BA – 2009 Actuals	2010 Actuals	Variance 2010 Actuals vs. 2009 Actuals	2011 Actuals	Variance 2011 Actuals vs. 2010 Actuals	2012 Bridge Year	Variance 2012 Bridge vs. 2011 Actuals	2013 Test Year	Variance 2013 Test vs. 2012 Bridge
Operations	$ 778,575	$ 694,259	$ 84,316	$ 870,153	$ 175,894	$ 947,441	$ 77,288	$ 1,159,195	$ 211,754	$ 1,423,862	$ 264,667
Maintenance	$ 657,080	$ 544,762	$ 112,318	$ 436,208	-$ 108,554	$ 528,873	$ 92,665	$ 601,800	$ 72,927	$ 713,650	$ 111,850
Billing and Collecting	$ 1,010,600	$ 970,447	$ 40,153	$ 922,744	-$ 47,703	$ 925,296	$ 2,552	$ 955,500	$ 30,204	$ 1,106,020	$ 150,520
Community Relations	$ 11,700	$ 10,826	$ 874	$ 9,114	-$ 1,712	$ 17,892	$ 8,778	$ 18,400	$ 508	$ 23,900	$ 5,500
Administrative and General	$ 1,439,785	$ 1,476,117	-$ 36,332	$ 1,620,369	$ 144,252	$ 1,776,253	$ 155,884	$ 1,899,865	$ 123,612	$ 2,197,640	$ 297,775
Total OM&A Expenses	$ 3,897,740	$ 3,696,411	$ 201,329	$ 3,858,588	$ 162,177	$ 4,195,755	$ 337,167	$ 4,634,760	$ 439,005	$ 5,465,072	$ 830,312
Variance from previous year				$ 162,177		$ 337,167		$ 439,005		$ 830,312	
Percent change (year over year)				4%		9%		10%		18%	
Percent Change: Test year vs. Most Current Actual						30.25%					
Simple average of %variance for all years						47.85%					10.4%
Compound Annual Growth Rate for all years											10.3%
Compound Growth Rate (2011 Actuals vs. 2009 Actuals)						13.51%					

The table below sets out the OM&A cost per customer and Full Time equivalent employees.

Table 4.4 – OM&A Per Customer and FTE

	Last Rebasing Year (2009 Board-Approved)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS
Number of Customers	14,411	14,460	14,584	14,742	14,952	15,165
Total Recoverable OM&A from Appendix 2-I	$ 3,897,740	$ 3,696,411	$ 3,858,588	$ 4,195,755	$ 4,634,760	$ 5,465,072
OM&A cost per customer	$ 270.47	$ 255.63	$ 264.58	$ 284.61	$ 309.98	$ 360.37
Number of FTEEs	26.3	26.8	32.5	34.3	36.3	40.5
Customers/FTEEs	547.95	539.55	448.74	429.80	411.90	374.44
OM&A Cost per FTEE	148,203.04	137,925.78	118,725.78	122,325.22	127,679.34	134,940.05

The number of customers for the years 2009, 2010 and 2011 include the average number of residential, GS<50 and GS>50 customers as at June 30th in each year. The number of customers for the years 2012 and 2013 include the residential, GS<50 and GS>50 customers as found in IHDSL's Load Forecast as set out in Exhibit 3.

The number of FTEEs includes both full time and part time employees. The part time employee calculation is based on the actual number of hours worked during the year vs. the number of hours a full time employee worked in each year.

Detailed information with respect to OM&A costs, arranged by USofA account, is provided in Exhibit 4, Tab 2, Schedule 2. Detailed information with respect to OM&A variances, arranged by USofA account, is provided in Exhibit 4, Tab 2, Schedule 3.

The variance used to determine the OM&A accounts requiring analysis has been prescribed by the Filing Requirements is $50,000 for a distributor with a distribution revenue requirement of less than or equal to $10 million. As IHDSL's revenue requirement is less than $10 million, details of variances over $50,000 will be provided. .

2013 Test Year OM&A Costs:

OM&A costs in this Exhibit represent IHDSL's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and government direction; and to maintain distribution business service quality and reliability at targeted performance levels. OM&A costs also include providing services to customers connected to IHDSL's distribution system, and meeting the requirements of the OEB's Standard Supply Service Code and Retail Settlement Code.

The proposed OM&A cost expenditures for the 2013 Test Year are the result of a business planning (5 year to 30 year plan) and work prioritization process that ensures that the most appropriate, cost effective solutions are put in place.

As a result of the planning process, IHDSL has identified the requirement for an additional 4.5 FTE's to support and maintain our business. Following is a list of the positions requested and the rationale;

1. Apprentice Meter Technician - 1 FTE

Justification/Drivers:

- Provide back up for IHDSL's 1 Journeyman Meter Technician
- Assist with meter re-verification that has to be completed by 2014. IHDSL's entire smart meter population (Sensus) was sealed in 2009 and currently has an estimated life of 6 years. Re-verification is required to keep IHDSL meters Measurement Canada compliant.
- Planed growth – with the forecasted growth in our service territory IHDSL requires a second Journeyman Meter Technician to meet customer demand

Impacts if Position not filled:

- No back up support for current Journeyman Meter Technician, impacting work/life balance, employee satisfaction and employee retention

- Risk of non-compliance with Measurement Canada and the associated fines
- IHDSL's ability to be in band for the Service Quality Indices for appointments scheduled, appointments met and appointments rescheduled
- Customer dissatisfaction with extended appointment commitments

2. Customer Service Collections Specialist – 1 FTE

Justification/Drivers:

- To provide consistency and transparency for customers (including Social Assistance Agencies) for collection issues under the new "Customer Service Rules"
- Maintain compliance with the 2010 and 2011 amendments to the DSC, RSC, and SSC, otherwise known as the "Customer Service Rules" pertaining to collections from all Residential customers
- Compliance and monitoring of the associated rules for the Arrears Management Plan (AMP), Low Income Energy Assistance Program (LEAP), and Equal Payment Plan have added complexities and new procedures over and above the day to day functions of traditional "collections" functions
- The new complexities require a "specialist" or subject matter expert approach to ensure that timelines for customers are adhered to.

Impacts if Position not filled:

- Customer dissatisfaction and risk of non-required collection notices or disconnections
- Risk of non-compliance with the "Customer Service Rules", thus non-compliance with the DSC, RSC and SSC.

3. Procurement and Inventory Officer – 1 FTE

Justification/Drivers:

- Provide back up for IHDSL's 1 Purchasing/Stock keeper position
- Increase in scope of current position as a result of;
    - ESA regulation 22/04 pertaining to materials and specifications
    - Increased time for miscellaneous maintenance responsibilities with additional staff brought on Board since 2009 and the required moves to facilitate staff
    - Increased capital expenditures requiring specialized material sourcing and procurement
    - IFRS impacts which have created incremental new processes which have to be maintained on a go forward basis, componentization, disposals and the addition of serialized inventory (smart meters, transformers, etc.) versus the "pooling" of assets
    - Increased building maintenance associated with IHDSL's Head Office and Operations Centre
- Provide centralized purchasing and receiving
- Increased control and administration for Request for Proposals (RFP) and Request for Quotation (RFQ)
- Increased level of accuracy and control over the corporations assets and inventory.

Impacts if Position not filled:

- No back up support for current Purchasing/Stock keeper position, impacting work/life balance, employee satisfaction and employee retention. Limited holiday selection to ensure constant streaming of ordering, stocking and issuing to operations
- New processes resulting from IFRS will not be able to be maintained thus impacting assets and inventory
- Risk of non-compliance with ESA regulations 22/04

- No capacity for additional functions thus impacting internal departments and, ultimately, the external customer.

4. IFRS/Financial Analyst – 1 FTE

Justification/Drivers:

- Support incremental new processes resulting from the transition from CGAAP to IFRS
    - Componentization, disposals and the serialization of inventory (smart meters, transformers, etc.) which now have to be tracked until disposal
- To maintain/support modified processes for additions and depreciation
- Requirement for increased skillset level (accounting specific to IFRS) to undertake the required analysis to ensure timely, accurate and relevant reporting of our capital assets and related analysis
- Increased Economic Evaluations due to forecasted growth
- Increased volumes for AR/AP as a result of additional staff, customer demand (internal and external). Monthly reconciliations have increased by 43% in a two year period and are expected to continue to increase
- Key position for internal development/training and succession planning for the Finance team
- Reduced dependency on consultants.

Impacts if Position not filled:

- Continuous increase of workload and slippage of deadlines will impact existing staff morale, thus retention
- Impact on relevant, accurate and timely reporting ultimately will impact the finance health of IHDSL

- Delays in AR/AP processing will have a direct result on customers both internal and external
- Increased consultant costs to manage at minimum the new processes resulting from the transition to IFRS .

5. Regulatory Analyst – .5 FTE

Justification/Drivers:

- Increase in Regulatory reporting (OEB, IESO, OPA, MOE) requirements by 37% since 2010
- Requirements under the DSC and the RRR Filing Requirements for SQI's and ESQR's for LDC's to track, monitor, and maintain records for audit purposes. For example, Service Quality Indicators are reported on an annual basis but need to be tracked, monitored on a monthly basis, thus the issuance of IHDSL's scorecard on a monthly basis
- Analyze monthly SQI's and ESQR's to identify trends, provide feedback and work with the respective internal departments to resolve process gaps
- Reduction in future COS preparation as historical data will be compiled and analyzed.

Impacts if Position not filled:

- Non-compliance with reporting requirements
- Delay in reporting deadlines.

OM&A Budgeting Process:

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, and provides a plan against which actual results are evaluated. Once approved, the budget is only revised if a material change in plan is required. In such cases, the revised budget also needs to re-approved by the Board of Directors.

The operating budget is a component of the overall budget process described in Exhibit 1, Tab 2, Schedule 2.

Operating Work Plans:

Each Department Manager provides input for the preparation of the departmental budget. The following directives are provided to each manager and director:

- All department budgets are built using previous year actual, current year forecast and current year budget as the base;
- Significant variances in spending from prior years must be explained and documented;
- Review the head count of the department for accuracy and outline any changes;
- Accounting prepares a total labour budget by department using projected wage and benefit costs. Overtime and account distribution are based on previous years actual plus any identified changes for the future year.

Income Tax, Large Corporation Tax and Ontario Capital Taxes:

IHDSL is subject to the payment of PILs under Section 93 of the *Electricity Act, 1998*, as amended. The Applicant does not pay Section 89 proxy taxes, and is exempt from the payment

of income and capital taxes under the *Income Tax Act (Canada)* and the Ontario *Corporations Tax Act*. Please refer to Exhibit 4, Tab 3, Schedule 1 and Appendix D for further tax calculations and a copy of the 2011 Federal tax return.

IHDSL has not included any one-time costs in the operating budget, with the exception of costs related to completing this Cost of Service application. The estimated costs for completing this application have been divided over four years. Table 4.5 provides these details as well as other regulatory expenses.

Regulatory Costs:

Regulatory costs include OEB ongoing costs and one time forecasted costs for consulting, Intervenor, and legal expenses associated with IHDS's COS rate application. These costs have been spread over a four year period. The costs that have been included are indicated below:

Table 4.5 Regulatory Costs

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2009 Board Approved)	Most Current Actuals Year 2011	2012 Bridge Year	Annual % Change	2013 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 49,990	$ 46,951	$ 48,000	2.23%	$ 49,000	2.08%
2	OEB Section 30 Costs (Applicant-originated)	5655		On-Going	$ 4,000	$ 6,546	$ 8,000	22.21%	$ 8,000	0.00%
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going	$ 4,000	$ 6,546	$ 8,000	22.21%	$ 8,000	0.00%
4	Expert Witness costs for regulatory matters	5655		On-Time					$ 16,000	
5	Legal costs for regulatory matters									
6	Consultants' costs for regulatory matters	5655		On-Time	$ 28,700	$ -	$ -		$ 25,000	
7	Operating expenses associated with staff resources allocated to regulatory matters									
8	Operating expenses associated with other resources allocated to regulatory matters [1]									
9	Other regulatory agency fees or assessments									
10	Any other costs for regulatory matters (please define)									
11	Intervenor costs			On-Time	$ 8,000				$ 9,000	
12	Sub-total - Ongoing Costs [3]		$ -		$ 94,690	$ 60,043	$ 64,000	6.59%	$ 115,000	79.69%
13	Sub-total - One-time Costs [4]		$ -		$ -	$ -	$ -		$ -	
14	Total		$ -		$ 94,690	$ 60,043	$ 64,000	6.59%	$ 115,000	79.69%

Low Income Assistance Program (LEAP)

IHDSL has included $11,304 of expense for the Low Income Assistance Program (LEAP) under Community Relations. This amount is based on 0.12% of the 2013 Test year Revenue Requirement, rounded.

Charitable Contributions

IHDSL has not included any charitable donations in OM&A expenses for 2013.

Green Energy Act

Exhibit 2 of this application provides IHDSL's plan for capital spending under the Green Energy Act. IHDSL does intend to record any incremental operating expenses related to the Green Energy Act in the proscribed deferral account and seek recovery on a historical/actual basis.

Inflation in 2012 Bridge and 2013 Test Year

The 2012 Bridge Year forecast is based on actual expenses as of January 31, 2012 plus expected expenditures for the remaining 11 months. Inflation has been applied to the expected expenditures except in cases where it is a known amount, such as increase to wages for union staff according to the collective agreement. In the 2013 Test Year expenses have been budgeted based on existing prices and increases if known. A basic inflation rate of 3% has been applied.

DEPARTMENTAL AND CORPORATE OM&A ACTIVITIES:

OPERATIONS & MAINTENANCE

The expenses for this department include all costs relating to the operation (5000-5096) and maintenance (5105-5195) of IHDSL's electrical system. This includes both direct labour costs and non-capital material spending to support both scheduled and reactive maintenance events. In addition, costs are allocated from support departments to cover the costs of Labour Burden, Engineering and Stores. IHDSL's maintenance strategy is, to the extent possible, to minimize reactive and emergency-type work through an effective planned maintenance program, including predictive and preventative actions. Additional details are outlined in IHDSL's Asset Management Plan in Exhibit 1.

IHDSL's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with IHDSL's capital project work so that where maintenance programs have identified matters which require capital investments, IHDSL may adjust its capital spending priorities to address those matters.

Predictive Maintenance:

Predictive maintenance activities involve the testing of elements of the distribution system. These activities include infrared thermography testing, transformer oil analysis, planned visual inspections and pole testing. These evaluation tools are all administered using a grid system with appropriate frequency levels. Any identified deficiencies found are prioritized and addressed within a suitable time frame.

Preventative Maintenance:

Preventative maintenance activities include inspection, servicing and repair of network components. This includes overhead and pad-mounted load break switch maintenance and cleaning/inspection of underground vaults. Also included are regular inspection and repair of substation components and ancillary equipment. T he work is performed using a combination of time and condition based methodologies.

Emergency Maintenance:

This item includes unexpected system repairs to the electrical system that must be addressed immediately. The costs include those related to repairs caused by storm damage, emergency tree trimming and on-call premiums. IHDSL constantly evaluates its maintenance data to adjust predictive and preventative actions. The ultimate objective is to reduce this emergency maintenance. An answering service company has been contracted to contact "on call" lineperson and supervisory staff in the event of service problems outside of normal business hours.

Service Work:

The majority of costs related to this work pertain to service upgrades requested by customers, and requests to provide safety coverage for work (overhead line cover ups). This includes service disconnections and reconnections by IHDSL for all service classes; assisting pre-approved contractors; the making of final connections after Electrical Safety Authority ("ESA") inspection for service upgrades; and changes of service locations.

Network Control Operations:

IHDSL maintains a Supervisory Control and Data Acquisition ("SCADA") system. Network operating costs are charged to account 5085.

Metering:

The metering department is responsible for the installation, testing, and commissioning of new and existing simple and complex metering installations. Testing of complex metering installations ensures the accuracy of the installation and verifies meter multipliers for billing purposes.

Revenue Protection is another key activity performed by Metering, by proactively investigating potential diversion and theft of power.

Substation Services:

Substation services activities address the maintenance of all equipment at IHDSL's 12 substations. This includes both labour costs and non-capital material spending to support both scheduled and emergency maintenance events. As with the maintenance activities, substation maintenance strategy focuses on minimizing, to the extent possible, emergency-type work by improving the effectiveness of IHDSL's planned maintenance program (including predictive and preventative actions) for its substations.

ENGINEERING DEPARTMENT

Engineering delivers drafting services from the design technicians for capital projects and provides distribution system asset information to many departments within IHDSL.

Engineering costs were allocated to operations, maintenance, capital, and Third Party receivable accounts based on total labour, truck and material costs. A standard overhead percentage is set at the beginning of the year for all jobs, and adjusted to actual at year end.

STORES/WAREHOUSE

Stores area is shared duties of other departments and is accountable for managing the procurement, control, and movement of materials within IHDSL's service centre. This includes monitoring inventory levels, issuing material receipts, material issues, and material returns as required. The cost of the stores department is allocated to all departmental, capital and Third Party receivable accounts as an overhead cost based on direct material costs. A standard overhead percentage is set at the beginning of the year and adjusted to actual at year end.

GARAGE/TRANSPORTATION FLEET

This area is shared duties of other departments and assists with the maintenance and control of approximately 11 fleet vehicles. Its objectives include keeping maintenance schedules to ensure vehicle reliability and safety, and the minimization of vehicle down time. Vehicle costs are allocated to operations, maintenance, capital and Third Party receivable accounts based on number of hours used. A standard "cost per hour" is set for all vehicles within the fleet (one rate for passenger vehicles and pickup and another rate for bucket trucks and work platforms). Costs are adjusted to actual at year end.

LABOUR BURDEN/SAFETY AND HEALTH

This department collects the cost of all employee benefits and payroll taxes such as EI, CPP, EHT, WSIB, and group insurances. Costs are allocated to all departments, capital and Third Party receivable amounts based on direct labour. An overhead rate is set at the beginning of each year and adjusted to actual at year end.

In addition, the cost of Safety and Health is included in this department. Costs include Health & Safety program supplies as well labour costs associated with safety meetings. IHDSL is committed to maximizing productivity and reducing risk of injury by initiating safety and health measures that focus on preventative actions. The commitment to safety and health is significant, and involves documenting unsafe behaviors, monitoring conformance to established standards and policies, determining the effectiveness of safety training and monitoring the resolution of safety recommendations/audits; commitment to continuous improvement in training; and identifying and correcting root causes for system deficiencies. IHDSL recently achieved the milestone of 250,000 hours without a loss-time incident and has applied to the Infrastructure Health and Safety Association (IHSA) in 2012 for the President's Award (Bronze Medal) for safety in the quest for zero lost time accidents. This is the second President's Award for IHDSL.

CUSTOMER SERVICE

The Customer Service group is responsible for the customer care activities for the approximately 14,740 customers in IHDL's service area. These activities include meter reading, billing, call centre, collections, and other back office functions. IHDSL aspires to achieve customer service excellence in its processes and customer programs. The costs associated with the Customer Service department are reported in accounts 5305 to 5340.

Meter Reading:

Prior to June 2012 meter reading services were contracted out to a non-affiliated third party under a service contract agreement. The transition to fully electronic meter reading for the Residential and GS>50 kW rate classes in conjunction with TOU billing was completed in June 2012.

Billing:

IHDSL performs monthly billing and issues 182,000 electricity invoices annually to customers. An annual billing schedule is created based on the meter reading schedule to ensure timely billing of services. The billing functions include the VEE processes (verification, estimation and edit); Electronic Billing Transactions (EBT) and retailer settlement functions for 1,387 retailer accounts; account adjustments; processing meter changes; and other various account related field service orders and mailing services. IHDSL offers customers a number of billing and payment options including walk-in counter service, an equal payment plan and a preauthorized payment plan.

Collections:

Collections involve a combination of activities, including the collection of overdue active accounts, security deposits and final bills for service termination. In an effort to minimize credit losses, IHDSL enforces a prudent credit policy in accordance with the Distribution System Code. Active overdue accounts are collected by in-house staff through notices, letters and direct telephone contact. Final bill collections are turned over to a collection agency after collection methods are exhausted.

Community Relations:

IHDSL is committed to providing consumer information and responses, in a timely and proactive manner, on electricity distribution and related issues. IHDSL maintains a presence in the communities it serves, where staff is available to answer customer questions in a friendly environment.

Since LDCs are the "face-to-the-customer" for the electricity industry, IHDSL has an important role to play in educating the public about electricity safety and energy conservation. IHDSL continues to participate with the OPA in administering programs directed at Energy Conservation and promoting the saveONenergy programs. In 2011 IHDSL participated in 41 community events including sponsorships, educational forums and retail events.

ADMINISTRATIVE AND GENERAL EXPENSES

Administrative and general expenses include expenses incurred in connection with the general administration of the utility's operations. W ithin IHDSL, the following functional areas are considered to be part of general administration and, as such, all expenses incurred within these functional areas are accounted for as administrative and general expenses:

- Executive Management (5605);
- Finance and Administrative Services (5615)

Executive Salaries and Expenses: 5605

This account includes expenses for IHDS's President/CEO and IHDSL Board of Directors.

Management Salaries and Expenses: 5610

Management Salaries and Expense is comprised of: senior management for accounting and customer service departments. The accounting and customer service departments are responsible for the preparation of statutory, management and Board of Directors financial reporting in accordance with GAAP/IFRS; all daily accounting functions, including, billing, accounts payable, accounts receivable, and general accounting; treasury functions including cash management, risk management, accounting systems and internal control processes; preparation of budgets and forecasts; and supporting tax compliance. The department is also responsible for all regulatory reporting and compliance with applicable codes and legislation governing IHDSL, including development and preparation of rate filings, performance reporting, and compliance.

Expenses included in Management Salaries and Expenses category include salary and related payroll burdens associated with the Chief Financial Officer, and Vice President of Corporate Services.

Administrative Services: 5615

Administrative Services is comprised of several sub-accounts: Human Resources, Regulatory, Accounting/Finance, Corporate Administration and Personnel Administration. The Finance department is responsible for the preparation of statutory, management and Board of Directors financial reporting in accordance with GAAP; all daily accounting functions, including accounts payable, accounts receivable, and general accounting; treasury functions including cash management, risk management, accounting systems and internal control processes; preparation of consolidated budgets and forecasts; and supporting tax compliance. The department is also responsible for all regulatory reporting and compliance with applicable codes and legislation governing IHDSL, including development and preparation of rate filings, performance reporting, and compliance.

The Human Resources & Corporate Administration and Personnel Administration department is responsible for providing support services required to operate an effective corporation as well as human resource-related support services.

Expenses included in Administrative Services include salary and related payroll burdens associated with the aforementioned functions.

Outside Service Employed: 5630

Outside Services Employed include, but are not limited to, consulting and professional fees of accountants and auditors, actuaries, legal services, public relations counsel and tax consultants.

Employee Post-Retirement Benefits: 5645

Employee Post-Retirement Benefits include annual expenses for post-retirement benefits provided to eligible IHDSL employees in accordance with company policy and as provided in the collective bargaining agreement between IHDSL and its union. The annual expense and liability are determined in accordance with Section 3461 of the CICA Handbook and supported by an actuarial valuation that is completed every three years.

Regulatory Expenses: 5655

Regulatory Expenses include those expenses incurred in connection with Decisions and Orders on Cost Awards for hearings, proceedings, technical sessions, and other matters before the OEB or other regulatory bodies, including annual assessment fees paid to a regulatory body. Annual fees assessed by the OEB are included in this expenditure category.

Miscellaneous General Expense: 5665

Membership dues and other miscellaneous costs are included in this account. IHDSL is a member of the Electricity Distributors Association and the Cornerstone Hydro Electric Concepts (CHEC) Group. CHEC has a membership of 12 small LDCs, who have worked together on common issues which have been mutually beneficial to the members. These include Conditions of Service, Economic Evaluation process, Smart Meter procurement, RFP for Collection Agency services and Audit services, CDM programs, IESO and settlement issues, joint training sessions and International Financial Reporting Standards.

Maintenance of General Plant: 5675

Expenses under Maintenance of General Plant include all costs of operating the service centre and office building. These include items such as: building utility costs, maintenance & repairs to the office building, lawn care & snow removal, and burdened salaries for facilities personnel.

Electrical Safety Authority ("ESA"): 5680

Expenses under Electrical Safety Authority ("ESA") fees include all annual charges from the ESA as well as annual audit expenses.

OM&A DETAILED COSTS TABLES

The following tables provide details of OM&A costs per USoA number for the years 2009 to 2011 Actual under CGAAP, and forecast for the 2012 Bridge Year under CGAAP and MIFRS, and 2013 Test Year under MIFRS.

Table 4.6: Detailed Account by Account Operation Expenses

Account Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual[2]	2011 Actual[2]	Bridge Year 2012[3]	Bridge Year 2012[3]	Test Year 2013
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
Operations							
5005 Operation Supervision and Engineering	$ 94,914	$ 128,729	$ 142,878	$ 142,878	$ 188,345	$ 188,345	$ 199,285
5010 Load Dispatching	$ 8,118	$ 6,141	$ 10,772	$ 10,772	$ 10,700	$ 10,700	$ 11,050
5012 Station Buildings and Fixtures Expense	$ 43,110	$ 48,791	$ 40,852	$ 40,852	$ 45,000	$ 45,000	$ 47,400
5014 Transformer Station Equipment - Operation Labour							
5015 Transformer Station Equipment - Operation Supplies and Expenses							
5016 Distribution Station Equipment - Operation Labour	$ 6,999	$ 6,943	$ 6,632	$ 6,632	$ 6,900	$ 6,900	$ 7,100
5017 Distribution Station Equipment - Operation Supplies and Expenses	$ 1,026	$ 1,755	$ 2,685	$ 2,685	$ 2,800	$ 2,800	$ 2,900
5020 Overhead Distribution Lines and Feeders - Operation Labour	$ 69,027	$ 74,500	$ 96,661	$ 96,661	$ 107,000	$ 107,000	$ 109,100
5025 Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 36,414	$ 34,688	$ 21,151	$ 21,151	$ 24,100	$ 24,100	$ 25,050
5030 Overhead Sub-transmission Feeders - Operation	$ 1,501	$ 2,739	$ 3,457	$ 3,457	$ 3,700	$ 3,700	$ 3,850
5035 Overhead Distribution Transformers - Operation	$ 36	$ 308	$ 1,260	$ 1,260	$ 900	$ 900	$ 1,000
5040 Underground Distribution Lines and Feeders - Operation Labour	$ 23,923	$ 24,103	$ 40,890	$ 40,890	$ 35,000	$ 35,000	$ 36,100
5045 Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 2,814	$ 10,394	$ 19,559	$ 19,559	$ 21,400	$ 21,400	$ 23,650
5050 Underground Sub-transmission Feeders - Operation							
5055 Underground Distribution Transformers - Operation							
5060 Street Lighting and Signal System Expense							
5065 Meter Expense	$ 55,781	$ 77,690	$ 77,675	$ 77,675	$ 206,500	$ 206,500	$ 339,849
5070 Customer Premises - Operation Labour	$ 43,380	$ 43,122	$ 42,062	$ 42,062	$ 47,000	$ 47,000	$ 48,400
5075 Customer Premises - Operation Materials and Expenses	$ 3,842	$ 7,544	$ 13,553	$ 13,553	$ 14,250	$ 14,250	$ 14,800
5085 Miscellaneous Distribution Expenses	$ 300,796	$ 394,603	$ 420,151	$ 420,151	$ 438,100	$ 438,100	$ 546,628
5090 Underground Distribution Lines and Feeders - Rental Paid							
5095 Overhead Distribution Lines and Feeders - Rental Paid	$ 2,578	$ 8,103	$ 7,203	$ 7,203	$ 7,500	$ 7,500	$ 7,700
5096 Other Rent							
Total - Operations	$ 694,259	$ 870,153	$ 947,441	$ 947,441	$ 1,159,195	$ 1,159,195	$ 1,423,862

Table 4.7: Detailed Account by Account Maintenance Expenses

Account Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual[2]	2011 Actual[2]	Bridge Year 2012[3]	Bridge Year 2012[3]	Test Year 2013
Maintenance							
5105 Maintenance Supervision and Engineering	$ 16,047	$ 17,770	$ 16,605	$ 16,605	$ 18,900	$ 18,900	$ 19,550
5110 Maintenance of Buildings and Fixtures - Distribution Stations							
5112 Maintenance of Transformer Station Equipment							
5114 Maintenance of Distribution Station Equipment	$ 42,337	$ 53,377	$ 37,758	$ 37,758	$ 54,600	$ 54,600	$ 56,230
5120 Maintenance of Poles, Towers and Fixtures	$ 32,833	$ 2,423	$ 1,671	$ 1,671	$ 5,550	$ 5,550	$ 19,340
5125 Maintenance of Overhead Conductors and Devices	$ 55,600	$ 60,636	$ 47,742	$ 47,742	$ 72,950	$ 72,950	$ 101,000
5130 Maintenance of Overhead Services	$ 66,730	$ 52,512	$ 67,089	$ 67,089	$ 60,750	$ 60,750	$ 62,650
5135 Overhead Distribution Lines and Feeders - Right of Way	$ 177,192	$ 127,532	$ 184,235	$ 184,235	$ 215,100	$ 215,100	$ 222,650
5145 Maintenance of Underground Conduit							
5150 Maintenance of Underground Conductors and Devices	$ 3,716	$ 1,996	$ 2,587	$ 2,587	$ 4,750	$ 4,750	$ 5,050
5155 Maintenance of Underground Services	$ 81,414	$ 69,956	$ 80,843	$ 80,843	$ 96,850	$ 96,850	$ 99,850
5160 Maintenance of Line Transformers	$ 35,542	$ 17,149	$ 58,987	$ 58,987	$ 31,650	$ 31,650	$ 82,530
5165 Maintenance of Street Lighting and Signal Systems							
5170 Sentinel Lights - Labour							
5172 Sentinel Lights - Materials and Expenses							
5175 Maintenance of Meters	$ 33,351	$ 32,857	$ 31,356	$ 31,356	$ 40,700	$ 40,700	$ 44,800
5178 Customer Installations Expenses - Leased Property							
5195 Maintenance of Other Installations on Customer Premises							
Total - Maintenance	$ 544,762	$ 436,208	$ 528,873	$ 528,873	$ 601,800	$ 601,800	$ 713,650

Table 4.8: Detailed Account by Account Billing & Collecting Expenses

Account Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual[2]	2011 Actual[2]	Bridge Year 2012[3]	Bridge Year 2012[3]	Test Year 2013
Billing and Collecting							
5305 Supervision	$ 50,754	$ 55,307	$ 63,860	$ 63,860	$ 64,900	$ 64,900	$ 66,800
5310 Meter Reading Expense	$ 137,851	$ 125,935	$ 69,829	$ 69,829	$ 33,300	$ 33,300	$ 38,000
5315 Customer Billing	$ 352,201	$ 335,375	$ 376,323	$ 376,323	$ 384,600	$ 384,600	$ 480,600
5320 Collecting	$ 293,500	$ 268,080	$ 286,478	$ 286,478	$ 327,800	$ 327,800	$ 340,820
5325 Collecting - Cash Over and Short	$ 30	$ 138	$ 35	$ 35	$ 50	$ 50	$ 100
5330 Collection Charges							
5335 Bad Debt Expense	$ 87,724	$ 85,020	$ 67,044	$ 67,044	$ 75,000	$ 75,000	$ 100,000
5340 Miscellaneous Customer Accounts Expenses	$ 48,387	$ 52,889	$ 61,727	$ 61,727	$ 69,850	$ 69,850	$ 79,700
Total - Billing and Collecting	$ 970,447	$ 922,744	$ 925,296	$ 925,296	$ 955,500	$ 955,500	$ 1,106,020

Table 4.9: Detailed Account by Account Community Relations Expenses

Account Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual[2]	2011 Actual[2]	Bridge Year 2012[3]	Bridge Year 2012[3]	Test Year 2013
Community Relations							
5405 Supervision							
5410 Community Relations - Sundry	$ 7,572	$ 5,867	$ 15,137	$ 15,137	$ 14,400	$ 14,400	$ 19,400
5415 Energy Conservation	$ -	$ 41	$ 208	$ 208			
5420 Community Safety Program	$ 1,704	$ 1,000	$ -	$ -	$ 1,500	$ 1,500	$ 1,500
5425 Miscellaneous Customer Service and Informational Expenses	$ 1,550	$ 2,206	$ 2,547	$ 2,547	$ 2,500	$ 2,500	$ 3,000
5505 Supervision							
5510 Demonstrating and Selling Expense							
5515 Advertising Expenses							
5520 Miscellaneous Sales Expense							
Total - Community Relations	$ 10,826	$ 9,114	$ 17,892	$ 17,892	$ 18,400	$ 18,400	$ 23,900

Table 4.10: Detailed Account by Account General & Administrative Expenses

Account Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual[2]	2011 Actual[2]	Bridge Year 2012[3]	Bridge Year 2012[3]	Test Year 2013
Administrative and General Expenses							
5605 Executive Salaries and Expenses	$ 209,979	$ 209,923	$ 218,153	$ 218,153	$ 227,875	$ 227,875	$ 233,375
5610 Management Salaries and Expenses	$ 189,103	$ 201,551	$ 214,395	$ 214,395	$ 225,025	$ 225,025	$ 232,247
5615 General Administrative Salaries and Expenses	$ 486,302	$ 576,121	$ 673,158	$ 673,158	$ 699,800	$ 699,800	$ 849,125
5620 Office Supplies and Expenses	$ 67,522	$ 73,767	$ 86,725	$ 86,725	$ 94,000	$ 94,000	$ 107,000
5625 Administrative Expense Transferred - Credit							
5630 Outside Services Employed	$ 64,876	$ 93,488	$ 104,144	$ 104,144	$ 148,500	$ 148,500	$ 152,895
5635 Property Insurance	$ 39,448	$ 75,239	$ 57,252	$ 57,252	$ 59,470	$ 59,470	$ 61,254
5640 Injuries and Damages	$ 34,487	$ 30,319	$ 34,561	$ 34,561	$ 37,000	$ 37,000	$ 38,110
5645 OMERS Pensions and Benefits	$ 28,828	$ 3,555	$ 3,461	$ 3,461	$ 4,400	$ 4,400	$ 4,500
5646 Employee Pensions and OPEB							
5647 Employee Sick Leave							
5650 Franchise Requirements							
5655 Regulatory Expenses	$ 99,623	$ 44,657	$ 56,135	$ 56,135	$ 56,000	$ 56,000	$ 107,000
5660 General Advertising Expenses							
5665 Miscellaneous General Expenses	$ 91,366	$ 104,035	$ 105,153	$ 105,153	$ 116,395	$ 116,395	$ 114,884
5670 Rent	$ 755	$ 319	$ 335	$ 335	$ 600	$ 600	$ 750
5672 Lease Payment Charge							
5675 Maintenance of General Plant	$ 155,401	$ 198,768	$ 181,370	$ 181,370	$ 221,000	$ 221,000	$ 286,500
5680 Electrical Safety Authority Fees	$ 8,427	$ 8,627	$ 8,928	$ 8,928	$ 9,800	$ 9,800	$ 10,000
5681 Special Purpose Charge Expense		$ 49,901					
5685 Independent Electricity System Operator Fees and Penalties							
5695 OM&A Contra Account							
6205 Donations	$ 844	$ 1,718	$ 531	$ 531	$ 1,000	$ 1,000	$ 1,000
6205 Donations, Sub-account LEAP Funding			$ 32,483	$ 32,483			
Total - Administrative and General Expenses	$ 1,476,961	$ 1,671,988	$ 1,776,784	$ 1,776,784	$ 1,900,865	$ 1,900,865	$ 2,198,640

VARIANCE ANALYSIS ON OM&A COSTS:

IHDSL has provided a detailed OM&A expense analysis covering the periods from IHDSL's last cost of service application. An analysis of expense changes by cost driver is provided in Table 4.11 with explanations below.

Table 4.11: OM&A Cost Drivers

OM&A Cost Driver Table

OM&A	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis					
Opening Balance	$ 3,897,740	$ 3,696,411	$ 3,858,588	$ 4,195,755	$ 4,634,760
Cost Driver #1 - 3% inflation		$ 110,892	$ 115,758	$ 125,873	$ 139,043
Cost Driver #2 - Eng/Operations Internalization	-$ 174,800	-$ 193,602	-$ 301,710	-$ 94,856	$ 81,834
Cost Driver #3 - Meter/Smart meter costs	$ -	$ -	-$ 47,000	$ 155,800	$ 25,000
Cost Driver #4 - Payroll cost	-$ 91,500	$ 198,787	$ 563,119	$ 231,781	$ 436,225
Cost Driver #5 - Bad debts	$ 58,000	-$ 2,700	-$ 20,500	$ 8,000	$ 22,750
Cost Driver #6 - Admin services	$ 6,971	$ 48,800	$ 19,000	$ 12,407	$ 125,460
Cost Driver #7 - Annual leap program			$ 8,500		
Closing Balance	$ 3,696,411	$ 3,858,588	$ 4,195,755	$ 4,634,760	$ 5,465,072

Cost Driver 1 – 3% Inflation

OM&A expenses have an inflation rate of 3% per year, this includes a 3% wage adjustment in line with the current PWU contract.

Cost Driver 2 – Engineering/Operations Internalization

2009 actuals reflect a variance of (-$174,800) primarily due to favorable weather conditions and favorable market tenders.

2010 actuals reflects a variance of (-$193,602), the two primary contributors to this variance are (-$160,602) for the internalization of contract work and (-$33,000) due to favorable market tenders in account 5315 for tree trimming. Although the internalization of the line crew brought a reduction of costs in the maintenance accounts this has been offset by an increase in payroll costs. The following provides background information re IHDSL's internalization project.

2011 actuals reflect a variance of (-$301,710), 2011 reflects savings from the internalization of contract work in the amount of (-$381,710), tree trimming costs of $56,000 a nd vehicle depreciation of $24,000.

2012 Bridge Year forecasts a v ariance of (-$94,856), of which (-$111,156) is due to the internalization of contract work, (-$24,000) is due to the correction of vehicle depreciation and $40,300 for tree trimming.

2013 Bridge year forecasts a variance of $81,834. (-$33,626) is due to the internalization of contract work, $17,240 due to increase miscellaneous increases and $98,120 forecasted costs for IHDSL's Asset Management Maintenance Program. Details of the forecasted costs by account are following the Background for Internalizing Line Staff.

Background for Internalizing Line Staff

IHDSL has contracted out its line work since inception in 1993. At that time, the service territory assets were purchased from Ontario Hydro utilizing 100% debt. As a conscious effort to preserve cash, a public line construction tender was issued and the successful proponent, McG Poleline, supplied the skilled non-unionized labour, vehicles, equipment and tools at reasonable costs.

The IHDSL/McG Poleline relationship was successful from 1993 to 2008. During the winter of 2008, McG Poleline was sold to K-Line Maintenance (K-Line). With the most recent McG Poleline contract expiring June 30, 2008, a public line tender was initiated. K-Line had

successfully bid a two-year contract with IHDSL. There was an overall cost increase (2007 to 2010) of 38%, mainly due to bringing prices closer to market rates.

With the relatively high increases in line work, staff had undergone an exercise to analyze the cost-benefit for internalizing a core group of five linemen. The analysis quantified the cost benefit for internalizing line staff and a public tender (2010-2013) was issued that had two options, one was for full contract line services and the other one factored in the phasing of the internalization of five linemen and associated vehicles and equipment. The public tender for full contract line services had an increase of 16% while the other option of internalizing five line staff and associated vehicles and equipment produced a reduction of 11%. It was estimated that there would be $141k in annual cost savings by hiring five internal line staff and another $47k in savings by purchasing three line vehicles and associated equipment.

The tender option was chosen to internalize line staff and associated vehicles and equipment. The process was completed in mid-2011 so full cost savings could only be achieved in the second half of 2011.

IHDSL Asset Management Maintenance Program

The following descriptions identified the preventative maintain activities that have been incorporated into the overall IHDSL Asset Management Maintenance program:

Annual fault indicator testing

IHDSL has installed approximately 40 sets of radio communicated fault indicators in its 44,000 Volt sub-transmission system. These fault indicators have reached an age that warrants a new maintenance program to ensure their accuracy and reliability. These fault indicators have a compulsory role in assisting emergency switching procedures during fault conditions due to

storms, tree contacts, vehicular accidents and defective devices. The fault indicator will send back a signal pinpointing an area where the problem exists. Through the use of the IHDSL's SCADA system, faults can be remotely switched at any hour of the day or night. To ensure accuracy and reliability of the fault indicator, IHDSL requires an annual testing program where Line personnel would be triggering the fault indicator manually in the field while operational staff monitor the SCADA system. In past experience, fault indicator failures have occurred due to water egress, battery failure, loose connections and UV damage. This causes uncertainty in switching operations which directly affects customer reliability and statistical data (SAIFI, SAIDI). This program will improve fault performance. The annual maintenance cost of **$12,100.00** has been included in the **5125** account in the 2013 budget.

Arc Flash Clothing Exchange Program

In protecting workers from potential electrical arc flash and arc blast hazards present in their work environment, IHDSL will provide exposed workers with the appropriate protective clothing in accordance with CSA Standard-Z462. The Occupational Health and Safety 25.(2)(h) – states that, "*the employer shall take every precaution reasonable in the circumstances for the protection of a worker*". It has been determined that the most cost effective way to provide such protective clothing is through a protective clothing exchange program with a commercial laundering company. This will ensure that all garments worn meet the required standards, that they are cleaned & repaired to the required rated protection and to minimize the financial investment in meeting the safety needs of our workers. The annual maintenance cost of **$10,000.00** has been included in the **5085** account in the 2013 budget.

Distribution Switch Maintenance Program

With over 600 in-line and disconnect style switches in IHDSL's distribution territory, a proactive maintenance program does not exist to ensure efficient operation and prolonged life of the overhead switches in our system. IHDSL will establish a maintenance program to inspect,

operate, clean and lubricate an approximate 45 out of a total of 350 overhead distribution switches in our system per year. This program will ensure switches will be tested and operate properly when required to do so. The annual maintenance cost of **$12,900.00** has been included in the **5125** account in the 2013 budget.

Underground Transformer and Switch Gear Maintenance Program

Underground transformer inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Elbows and terminators of the Transformers and Switchgears are visually inspected according to the Minimum Inspection Requirements in the Distribution system Code (every 3 years Urban and every 6 years rural) by the infra-red scanning program. Underground Transformers and Switch Gears have their lids opened and all connections are inspected by the infra-red scanning process. Underground Transformers and Switch Gears are exposed to a variety of elements which can cause potential public safety hazards, equipment deterioration and operational challenges. In addition to line patrols and infra-red testing , a more in-depth maintenance program will create an opportunity to lubricate and operate infrequently used load break elbows and switches; repair and/or replace corroded connectors caused by acidic soil conditions and standing water; identify and correct any abnormal soil infiltration; inspect, repair or replace transformer grounding; re-fresh deteriorated nomenclature and identify any damage to the outside of the equipment caused by pedestrian, vehicular and municipal maintenance traffic. A program of this scope has not been budgeted before in the past however, with an Annual Underground Transformer and Switch Gear Maintenance Program, IHDSL would be able to proactively complete more thorough maintenance. The annual maintenance cost of **$49,780.00** has been included in the **5161** account in the 2013 budget.

Pole Maintenance Program

Pole inspection is a requirement under the Minimum Inspection Requirements of the Distribution System code. Every year IHDSL tests an approximate 1/8 of the 10,000 poles in its distribution territory. Poles that are found in need of replacement are capitalized, however poles that are tested and pass often are in the need of maintenance. Aproximately 200-215 poles per year receive comments back to IHDSL from the pole testers indicating deficiencies. Items such as slack or loose guy wires, guy strain insulators pulled apart or broken, guy guards out of position or missing, loose grounding connections and missing nomenclature are a few examples. A program of this scope has not been budgeted before in the past however with an Annual Pole Maintenance Program, IHDSL would be able to address the issues raised by our contractor and remediate potential hazards to the public and staff. The annual maintenance cost of **$13,440.00** has been included in the **5120** account in the 2013 budget.

Cost Driver 3 - Meter/Smart Meter Costs

Meter reading expenses in 2010 and 2011 were reduced by $47,000 and $36,000 respectively, as IHDSL transitioned to electronic meter reading in June 2011. In July 2011, IHDSL began Time of Use billing and submitted our Prudence Review Application to the Ontario Energy Board under Board File #EB-2011-0435. On May 3, 2012, in its Decision and Order, the Board approved all capital and OM&A costs relating to the smart meter infrastructure.

With the Decision and Order, costs related to AMI/MDMR functions were transferred to annual OM&A costs for a total of $191,800. The following table provides an estimate by function and vendor for AMI/MDMR costs.

Function	Vendor	Monthly	Annual	Type	Account
ODS	Kinetiq (Savage Data)	2,500	30,000	operations	5065
RNI	Sensus	6,750	81,000	operations	5065
audits/SLA/'sync b/u-annual contract	Util-assist		31,500	admin	5630
Broadband	Pt 2 Pt	192	2,300	operations	5065
Sensus Shared Test facilities	PowerStream		5,000	operations	5065
Collections	Olameter	2,000	24,000	b&c	5320
AMI security audit	Bell-Wurld Tech (currently)		15,000	admin	5630
Software maintenance	Northstar-Home Connect		3,000	admin	5675

Cost Driver 4 – Payroll Costs

2009's variance of (-$91,500) is attributed to a reduction of employee training, set up of post-retirement benefits and a delay in hiring the Regulatory Manager.

2010 variance of $198,787 is primarily attributable to hiring of the Regulatory Manager, re-allocation of maintenance expense to payroll expense resulting from the internalization of contract work.

2011 variance of $563,119 is attributable to the re-allocation of maintenance expense to payroll expense from the internalization of contract work and the hiring of the following positions,

- Professional Engineer 1 FTE
- GIS/Technician 1 FTE
- HR/Admin Assistant .5 FTE

The Engineering and GIS Technician positions were required for *Ontario Regulation 22-04* compliance and new distributed generation applications as allowed by the *Green Energy Act*. The HR/Admin position provided payroll support and admin support for the additional training requirements and increased HR demands.

2012 Bridge Year variance of $231,781 is primarily attributable to the first full year of payroll costs for the new hires in 2011 and increased employee training costs.

2013 Test Year – the primary driver for payroll costs is IHDSL's requirement for an additional 4.5 FTE. The justification for these 5 positions has been provided in the header **2013 Test Year OM&A Costs** within this Exhibit on page 5, Schedule 1. The positions requested are required due to incremental work processes as a result of the transition to IFRS, employee support back up and compliance with changes to the DSC, RSC, SSC and the RRR Filing Guide.

Cost Driver 5 – Bad Debts

Prior to 2010, as part of its Allowance for Doubtful Accounts calculation, IHDSL wrote off bad debt for uncollectable accounts in the preceding year. For example on December 31, 2009 accounts deemed uncollectable for 2007 were written off. This lag meant in some cases accounts were outstanding for between one and two years before they were written off. In 2010 a change in policy occurred advancing the write off date from one year to six months. The increase of $85,020 in 2010 was largely the result of a one-time occurrence of 18 months of bad debt being written off during this change in policy. In 2011, the reduction in bad debts was a combination of improved collections and a return to a 12 month period for write offs. The increase in the 2012 bridge year is reflective of the slow payments occurring during the later part of 2011 and early 2012.

Cost Driver 5 – Administrative Service

With the increase in FTE, administrative and support costs have increased accordingly, including internet, office, printing and stationary supplies. General plant for software maintenance has also increased due to new software requirements and licensing requirements.

The two main drivers are increase in General Plant software maintenance and increased Regulatory costs due to the complexity of the rate application process.

Variance Analysis by Account:

Consistent with the Ontario Energy Board Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 22 2012, IHDSL has provided variance analyses for the 2013 Test Year vs. 2009 Actual (last rebase year) and between the 2013 Test Year and 2011 Actual (Most Current Actual). IHDSL has reviewed the variance of each USoA account and provided explanations for variances exceeding a materiality threshold of $50,000. The variances are indicated in the following tables and an explanation of each variance is presented following the appropriate table.

Table 4.12 Operations Expenses – Account Variances

Account	Description	Last Board-approved Rebasing Year (2009 Year)	Most Current Actuals Year 2011	Test Year 2013	Test Year Versus Last Rebasing		Test Year Versus Most Current Actuals	
					Variance ($)	Percentage	Variance ($)	Percentage
Reporting Basis		CGAAP	CGAAP	MIFRS				
Operations								
5005	Operation Supervision and Engineering	$ 72,325	$ 142,878	$ 199,285	$ 126,960	175.54%	$ 56,407	39.48%
5010	Load Dispatching	$ 6,050	$ 10,772	$ 11,050	$ 5,000	82.64%	$ 278	2.58%
5012	Station Buildings and Fixtures Expense	$ 40,400	$ 40,852	$ 47,400	$ 7,000	17.33%	$ 6,548	16.03%
5014	Transformer Station Equipment - Operation Labour		$ -	$ -	$ -		$ -	
5015	Transformer Station Equipment - Operation Supplies and Expenses		$ -	$ -	$ -		$ -	
5016	Distribution Station Equipment - Operation Labour	$ 7,400	$ 6,632	$ 7,100	-$ 300	-4.05%	$ 468	7.06%
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ 2,000	$ 2,685	$ 2,900	$ 900	45.00%	$ 215	8.01%
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 40,850	$ 96,661	$ 109,100	$ 68,250	167.07%	$ 12,439	12.87%
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 36,600	$ 21,151	$ 25,050	-$ 11,550	-31.56%	$ 3,899	18.43%
5030	Overhead Sub-transmission Feeders - Operation	$ 3,250	$ 3,457	$ 3,850	$ 600	18.46%	$ 393	11.37%
5035	Overhead Distribution Transformers - Operation	$ 3,650	$ 1,260	$ 1,000	-$ 2,650	-72.60%	-$ 260	-20.63%
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 27,000	$ 40,890	$ 36,100	$ 9,100	33.70%	-$ 4,790	-11.71%
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 8,950	$ 19,559	$ 23,650	$ 14,700	164.25%	$ 4,091	20.92%
5050	Underground Sub-transmission Feeders - Operation		$ -	$ -	$ -		$ -	
5055	Underground Distribution Transformers - Operation	$ 250	$ -	$ -	-$ 250	-100.00%	$ -	
5060	Street Lighting and Signal System Expense		$ -	$ -	$ -		$ -	
5065	Meter Expense	$ 67,750	$ 77,675	$ 339,849	$ 272,099	401.62%	$ 262,174	337.53%
5070	Customer Premises - Operation Labour	$ 47,200	$ 42,062	$ 48,400	$ 1,200	2.54%	$ 6,338	15.07%
5075	Customer Premises - Operation Materials and Expenses	$ 9,500	$ 13,553	$ 14,800	$ 5,300	55.79%	$ 1,247	9.20%
5085	Miscellaneous Distribution Expenses	$ 401,700	$ 420,151	$ 546,628	$ 144,928	36.08%	$ 126,477	30.10%
5090	Underground Distribution Lines and Feeders - Rental Paid		$ -	$ -	$ -		$ -	
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ 3,700	$ 7,203	$ 7,700	$ 4,000	108.11%	$ 497	6.90%
5096	Other Rent				$ -		$ -	
Total - Operations		$ 778,575	$ 947,441	$ 1,423,862	$ 645,287	82.88%	$ 476,421	50.29%

2013 TEST YEAR vs. 2009 ACTUAL:

Operational Expenses

Account 5006

The variance in account 5006 in the 2013 Test Year compared to the last rebasing year is due to the hiring of a GIS Technician in April 2011 and an Engineering student for 3 terms in 2011 and 2012.

Account 5020 – Overhead Distribution Lines & Feeders

The variance in account 5020 in the 2013 Test Year compared to the last rebasing year is forecasted maintenance as a result of weather impacts.

Account 5065 – Meter Expense

Meter reading expenses in 2010 and 2011 were reduced by $47,000 and $36,000 respectively, as IHDSL transitioned to electronic meter reading in June 2011. In July 2011, IHDSL began Time of Use billing and submitted our Prudence Review Application to the Ontario Energy Board under Board File #EB-2011-0435. On May 3, 2012, in its Decision and Order, the Board approved all capital and OM&A costs relating to the smart meter infrastructure.

With the Decision and Order, costs related to AMI/MDMR functions were transferred to annual OM&A costs for a total of $191,800. The following table provides an estimate by function and vendor for AMI/MDMR costs.

Function	Vendor	Monthly	Annual	Type	Account
ODS	Kinetiq (Savage Data)	2,500	30,000	operations	5065
RNI	Sensus	6,750	81,000	operations	5065
audits/SLA/'sync b/u-annual contract	Util-assist		31,500	admin	5630
Broadband	Pt 2 Pt	192	2,300	operations	5065
Sensus Shared Test facilities	PowerStream		5,000	operations	5065
Collections	Olameter	2,000	24,000	b&c	5320
AMI security audit	Bell-Wurld Tech (currently)		15,000	admin	5630
Software maintenance	Northstar-Home Connect		3,000	admin	5675

Table 4.13 Maintenance Expenses – Account Variances

Account	Description	Last Board-approved Rebasing	Most Current Actuals Year 2011	Test Year	Test Year Versus Last		Test Year Versus Most	
					Variance ($)	Percentage Change (%)	Variance ($)	Percentage Change (%)
Reporting Basis		CGAAP	CGAAP	MIFRS				
Maintenance								
5105	Maintenance Supervision and Engineering	$ 11,950	$ 16,605	$ 19,550	$ 7,600	63.60%	$ 2,945	17.74%
5110	Maintenance of Buildings and Fixtures - Distribution Stations		$ -	$ -	$ -		$ -	
5112	Maintenance of Transformer Station Equipment		$ -	$ -	$ -		$ -	
5114	Maintenance of Distribution Station Equipment	$ 39,300	$ 37,758	$ 56,230	$ 16,930	43.08%	$ 18,472	48.92%
5120	Maintenance of Poles, Towers and Fixtures	$ 44,680	$ 1,671	$ 19,340	-$ 25,340	-56.71%	$ 17,669	1057.39%
5125	Maintenance of Overhead Conductors and Devices	$ 143,500	$ 47,742	$ 101,000	-$ 42,500	-29.62%	$ 53,258	111.55%
5130	Maintenance of Overhead Services	$ 67,700	$ 67,089	$ 62,650	-$ 5,050	-7.46%	-$ 4,439	-6.62%
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 188,100	$ 184,235	$ 222,650	$ 34,550	18.37%	$ 38,415	20.85%
5145	Maintenance of Underground Conduit		$ -	$ -	$ -		$ -	
5150	Maintenance of Underground Conductors and Devices	$ 13,050	$ 2,587	$ 5,050	-$ 8,000	-61.30%	$ 2,463	95.21%
5155	Maintenance of Underground Services	$ 64,550	$ 80,843	$ 99,850	$ 35,300	54.69%	$ 19,007	23.51%
5160	Maintenance of Line Transformers	$ 50,250	$ 58,987	$ 82,530	$ 32,280	64.24%	$ 23,543	39.91%
5165	Maintenance of Street Lighting and Signal Systems		$ -	$ -	$ -		$ -	
5170	Sentinel Lights - Labour		$ -	$ -	$ -		$ -	
5172	Sentinel Lights - Materials and Expenses		$ -	$ -	$ -		$ -	
5175	Maintenance of Meters	$ 34,000	$ 31,356	$ 44,800	$ 10,800	31.76%	$ 13,444	42.88%
5178	Customer Installations Expenses - Leased Property				$ -		$ -	
5195	Maintenance of Other Installations on Customer Premises				$ -		$ -	
Total - Maintenance		$ 657,080	$ 528,873	$ 713,650	$ 56,570	8.61%	$ 184,777	34.94%

2013 TEST YEAR vs. 2009 ACTUAL:

Maintenance Expenses

There are no expense variances greater than $50,000 when comparing the 2013 Test Year with the 2009 Actual expenses.

Table 4.13 Billing & Collecting Expenses – Account Variances

Account	Description	Last Board-approved Rebasing	Most Current Actuals Year 2011	Test Year	Test Year Versus Last		Test Year Versus Most	
					Variance ($)	Percentage Change (%)	Variance ($)	Percentage Change (%)
Reporting Basis		CGAAP	CGAAP	MIFRS				
Billing and Collecting								
5305	Supervision	$ 44,900	$ 63,860	$ 66,800	$ 21,900	48.78%	$ 2,940	4.60%
5310	Meter Reading Expense	$ 153,200	$ 69,829	$ 38,000	-$ 115,200	-75.20%	-$ 31,829	-45.58%
5315	Customer Billing	$ 383,950	$ 376,323	$ 480,600	$ 96,650	25.17%	$ 104,277	27.71%
5320	Collecting	$ 345,200	$ 286,478	$ 340,820	-$ 4,380	-1.27%	$ 54,342	18.97%
5325	Collecting - Cash Over and Short	$ 50	$ 35	$ 100	$ 50	100.00%	$ 65	185.71%
5330	Collection Charges		$ -	$ -	$ -		$ -	
5335	Bad Debt Expense	$ 30,000	$ 67,044	$ 100,000	$ 70,000	233.33%	$ 32,956	49.16%
5340	Miscellaneous Customer Accounts Expenses	$ 53,300	$ 61,727	$ 79,700	$ 26,400	49.53%	$ 17,973	29.12%
Total - Billing and Collecting		$ 1,010,600	$ 925,296	$ 1,106,020	$ 95,420	9.44%	$ 180,724	19.53%

2013 TEST YEAR vs. 2009 ACTUAL:

Billing & Collecting Expenses

Account 5315 – Customer Billing

The increase in the 2013 Test Year is directly attributable to the forecasted customer growth which is highlighted in Exhibit 2 and Exhibit 3.

Account 5335 – Bad Debt

Prior to 2010, as part of its Allowance for Doubtful Accounts calculation, IHDSL wrote off bad debt for uncollectable accounts in the preceding year. For example on December 31, 2009 accounts deemed uncollectable for 2007 were written off. This lag meant in some cases accounts were outstanding for between one and two years before they were written off. In 2010 a change in policy occurred advancing the write off date from one year to six months. The increase of $85,020 in 2010 was largely the result of a one-time occurrence of 18 months of bad debt being written off during this change in policy. In 2011, the reduction in bad debts was a combination of improved collections and a return to a 12 month period for write offs. The increase in the

2012 bridge year is reflective of the slow payments occurring during the later part of 2011 and early 2012.

Table 4.14 Community Relations Expenses – Account Variances

Account	Description	Last Board-approved Rebasing	Most Current Actuals Year 2011	Test Year	Test Year Versus Last		Test Year Versus Most	
					Variance ($)	Percentage Change (%)	Variance ($)	Percentage Change (%)
Reporting Basis		CGAAP	CGAAP	MIFRS				
Account	Description							
Community Relations								
5405	Supervision	$ -	$ -	$ -	$ -		$ -	
5410	Community Relations - Sundry	$ 8,100	$ 15,137	$ 19,400	$ 11,300	139.51%	$ 4,263	28.16%
5415	Energy Conservation	$ -	$ 208	$ -	$ -		-$ 208	-100.00%
5420	Community Safety Program	$ 1,000	$ -	$ 1,500	$ 500	50.00%	$ 1,500	
5425	Miscellaneous Customer Service and Informational Expenses	$ 2,600	$ 2,547	$ 3,000	$ 400	15.38%	$ 453	17.79%
5505	Supervision	$ -	$ -	$ -	$ -		$ -	
5510	Demonstrating and Selling Expense	$ -	$ -	$ -	$ -		$ -	
5515	Advertising Expenses	$ -	$ -	$ -	$ -		$ -	
5520	Miscellaneous Sales Expense	$ -	$ -	$ -	$ -		$ -	
Total - Community Relations		$ 11,700	$ 17,892	$ 23,900	$ 12,200	104.27%	$ 6,008	33.58%

2013 TEST YEAR vs. 2009 ACTUAL:

Community Relations

There are no expense variances greater than $50,000 when comparing the 2013 Test Year with the 2009 Actual expenses.

Table 4.1.5 - Administrative and General Expenses – Account Variances

Account	Description	Last Board-approved Rebasing	Most Current Actuals Year 2011	Test Year	Test Year Versus Last		Test Year Versus Most	
					Variance ($)	Percentage Change (%)	Variance ($)	Percentage Change (%)
Reporting Basis		CGAAP	CGAAP	MIFRS				
Administrative and General Expenses								
5605	Executive Salaries and Expenses	$ 214,350	$ 218,153	$ 233,375	$ 19,025	8.88%	$ 15,222	6.98%
5610	Management Salaries and Expenses	$ 165,525	$ 214,395	$ 232,247	$ 66,722	40.31%	$ 17,852	8.33%
5615	General Administrative Salaries and Expenses	$ 519,170	$ 673,158	$ 849,125	$ 329,955	63.55%	$ 175,967	26.14%
5620	Office Supplies and Expenses	$ 82,450	$ 86,725	$ 107,000	$ 24,550	29.78%	$ 20,275	23.38%
5625	Administrative Expense Transferred - Credit		$ -	$ -	$ -		$ -	
5630	Outside Services Employed	$ 56,800	$ 104,144	$ 152,895	$ 96,095	169.18%	$ 48,751	46.81%
5635	Property Insurance	$ 44,200	$ 57,252	$ 61,254	$ 17,054	38.58%	$ 4,002	6.99%
5640	Injuries and Damages	$ 40,600	$ 34,561	$ 38,110	-$ 2,490	-6.13%	$ 3,549	10.27%
5645	OMERS Pensions and Benefits	$ 7,516	$ 3,461	$ 4,500	-$ 3,016	-40.13%	$ 1,039	30.02%
5646	Employee Pensions and OPEB		$ -	$ -	$ -		$ -	
5647	Employee Sick Leave		$ -	$ -	$ -		$ -	
5650	Franchise Requirements		$ -	$ -	$ -		$ -	
5655	Regulatory Expenses	$ 90,690	$ 56,135	$ 107,000	$ 16,310	17.98%	$ 50,865	90.61%
5660	General Advertising Expenses		$ -	$ -	$ -		$ -	
5665	Miscellaneous General Expenses	$ 51,434	$ 105,153	$ 114,884	$ 63,450	123.36%	$ 9,731	9.25%
5670	Rent	$ 350	$ 335	$ 750	$ 400	114.29%	$ 415	123.88%
5672	Lease Payment Charge		$ -	$ -	$ -		$ -	
5675	Maintenance of General Plant	$ 150,600	$ 181,370	$ 286,500	$ 135,900	90.24%	$ 105,130	57.96%
5680	Electrical Safety Authority Fees	$ 16,100	$ 8,928	$ 10,000	-$ 6,100	-37.89%	$ 1,072	12.01%
5681	Special Purpose Charge Expense		$ -	$ -	$ -		$ -	
5685	Independent Electricity System Operator Fees and Penalties		$ -	$ -	$ -		$ -	
5695	OM&A Contra Account		$ -	$ -	$ -		$ -	
6205	Donations	$ 1,600	$ 531	$ 1,000	-$ 600	-37.50%	$ 469	88.32%
6205	Donations, Sub-account LEAP Funding	$ -	$ 32,483	$ -	$ -		-$ 32,483	-100.00%
Total - Administrative and General Expenses		$ 1,441,385	$ 1,776,784	$ 2,198,640	$ 757,255	52.54%	$ 421,856	23.74%
Total OM&A		$ 3,899,340	$ 4,196,286	$ 5,466,072	$ 1,566,732	40.18%	$ 1,269,786	30.26%

2013 TEST YEAR vs. 2009 ACTUAL:

TABLE 4.2.15: OPERATIONS:

Account 5615- General Administrative Salaries & Expenses

The increase in the 2013 Test Year compared to 2009 rebasing year is primarily due to additional 2.5 FTE requirements.

In 2013 our FTE is forecasted to increase by the following positions for account 5615,

- IFRS Analyst- Jan 1, 2013
- Part Time Regulatory Analyst – Jan 1, 2013
- Purchasing Analyst – Jan 1, 2014

The justification for these all positions has been provided in the header **2013 Test Year OM&A Costs** within this Exhibit on page 5, Schedule 1.

Account 5630 – Outside Services

The increase in 2013 Test Year compared to the 2009 rebasing year is due to increase in Audit, Consulting and Legal costs.

Account 5665 – Miscellaneous General Expense

The increase in the 2013 Test Year compared to 2009 rebasing is primarily based on an increase in Health and Safety costs due to the internalization of IHDSL's line crew and new hires. The costs have increased from $2,875 in 2009 to $13,700 in 2013. Secondary contributors are increases to postage/Purolator expenses and postage meter rental due to customer growth.

Account 5675 – Maintenance of General Plant

As the number of systems, applications, and FTE increase the maintenance of general plant will continue. The major contributing factors from the 2013 Test Year to the 2009 rebasing year is the following software/support applications that have contributed to the increase for a total of $62,000 beyond annual support and licensing.

- Teleworks - $14,000
- General Network Admin - $14,000
- ASI - $22,000

EMPLOYEE COMPENSATION, INCENTIVE PLAN EXPENSES, PENSION EXPENSE AND POST RETIREMENT BENEFITS:

Compensation/Performance System

Union

IHDSL's unionized staff is represented by the Power Workers Union. The current collective agreement expires July 6, 2013 and IHDSL will be entering formal negotiations prior to that date. The current agreement, which was entered into in May 2010, includes annual wage increases of 3.0% effective July 7, 2010, July 7, 2011 and July 7, 2012.

Executive/Management

Executive and Management compensation plan consists of salaries and benefits. Each position within the company has been placed on a pay scale which is reviewed annually by senior management and the Board of Directors' Compensation Committee. Each employee's position within their respective range is reviewed based on performance and an inflationary adjustment. Changes to senior management compensation, if any, are approved by the Board of Directors. IHDSL does not offer any incentive or bonus compensation.

Benefits

A comprehensive and competitive benefits package exists which includes medical insurance, life insurance, vacation and a company-sponsored retirement plan. The plans are designed to address the health and welfare needs of the employee population with similar plans for both union and management employees.

All full time staff participates in the OMERS pension plan.

All full time staff participates in Post-Retirement Benefits. The accrued expense is based on an actuarial valuation. The latest copy of the valuation has been provided as Appendix C.

Employee Compensation and Benefits:

The employee complement, compensation and benefit information is provided in Table 4.16 below.

Table 4.16 Employee Compensation2010 Compared to 2009

	Last Rebasing Year (2009 Board-Approved)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS
Number of Employees (FTEs including Part-Time)[1]						
Executive						
Management	8.0	9.0	10.0	10.5	11.5	11.5
Non-Union						
Union	18.3	17.8	22.5	23.8	24.8	29.0
Total	26.3	26.8	32.5	34.3	36.3	40.5
Number of Part-Time Employees						
Executive						
Management				0.5	0.5	0.5
Non-Union						
Union			0.5	0.5	0.5	1.0
Total	-	-	0.5	1.0	1.0	1.5
Total Salary and Wages						
Executive						
Management	763,988	753,181	884,166	995,530	1,162,162	1,217,027
Non-Union						
Union	944,616	857,886	964,139	1,349,452	1,533,214	1,916,707
Total	$ 1,708,604	$ 1,611,067	$ 1,848,304	$ 2,344,982	$ 2,695,376	$ 3,133,734
Current Benefits						
Executive						
Management	174,100	157,021	186,477	217,805	272,291	296,878
Non-Union						
Union	234,594	188,590	213,432	299,128	362,440	475,994
Total	$ 408,693	$ 345,611	$ 399,909	$ 516,933	$ 634,730	$ 772,872
Accrued Pension and Post-Retirement Benefits						
Executive						
Management	2,192	1,511	1,094	1,059	1,394	1,278
Non-Union						
Union	5,015	2,989	2,461	2,402	3,006	3,222
Total	$ 7,207	$ 4,500	$ 3,555	$ 3,461	$ 4,400	$ 4,500
Total Benefits (Current + Accrued)						
Executive	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ 176,292	$ 158,532	$ 187,571	$ 218,865	$ 273,685	$ 298,156
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ 239,608	$ 191,579	$ 215,893	$ 301,529	$ 365,446	$ 479,216
Total	$ 415,900	$ 350,111	$ 403,464	$ 520,394	$ 639,130	$ 777,372
Total Compensation (Salary, Wages, & Benefits)						
Executive	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ 940,280	$ 911,713	$ 1,071,736	$ 1,214,394	$ 1,435,847	$ 1,515,183
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ 1,184,225	$ 1,049,464	$ 1,180,032	$ 1,650,981	$ 1,898,660	$ 2,395,923
Total	$ 2,124,504	$ 1,961,178	$ 2,251,768	$ 2,865,376	$ 3,334,506	$ 3,911,106
Compensation - Average Yearly Base Wages						
Executive						
Management	90,994	79,303	82,879	88,270	94,710	99,290
Non-Union						
Union	51,500	48,159	42,159	53,483	58,458	63,129
Total						
Compensation - Average Yearly Overtime						
Executive						
Management	4,505	4,383	5,538	6,543	6,348	6,538
Non-Union						
Union	118	37	691	3,217	3,365	2,964
Total						
Compensation - Average Yearly Incentive Pay						
Executive						
Management						
Non-Union						
Union						
Total						
Compensation - Average Yearly Benefits						
Executive						
Management	22,036	17,447	18,648	20,743	23,677	25,815
Non-Union						
Union	13,093	10,595	9,486	12,568	14,614	16,414
Total						
Total Compensation	$ 2,124,504	$ 1,961,178	$ 2,251,768	$ 2,865,376	$ 3,334,506	$ 3,911,106
Total Compensation Capitalized (CGAAP)	$ 147,000	$ 135,014	$ 245,271	$ 474,840	$ 697,092	
Total Compensation Charged to OM&A (CGAAP)	$ 1,977,504.46	$ 1,826,163.51	$ 2,006,497.46	$ 2,390,535.53	$ 2,637,414.49	
Total Compensation Capitalized (MIFRS)				$ 474,840	$ 697,092	$ 792,446
Total Compensation Charged to OM&A (MIFRS)				$ 2,390,535.53	$ 2,637,414.49	$ 3,118,660.00

Management - +1.25

Cost - $85,417

IHDSL delayed hiring a Regulatory /CDM Manager from 2009 to 2010 for a cost of $75,000 additionally an Operational Engineer was hired for the last 2 months of 2010 at a cost of $10,417 for a total expense of $85,417.

Union - +5

Cost – $111,870

In 2010 IHDSL internalized contract maintenance functions. These functions were previously contracted out, thus creating a cost avoidance in maintenance expense.

2011 Compared to 2010

Management – 0

Cost - 0

No hires in 2011 but the full cost of the Operational Engineer is expensed for $95,833.

Union - +.7

Cost - $26,876

In 2011 IHDSL hired a part-time HR Admin Assistant for a cost of $8,438 and a GIS Technican who started in July for a cost of $18,438.

2012 Bridge Compared to 2011

Management - 0

Cost – 0

No new hires in 2012.

Union – +.5

Cost – $19,663

In 2012 IHDSL hired a Smart Grid Engineer in June for a cost of $19,663.

2013 Test Compared to 2012

Management – 0

Cost – 0

No management hires are forecasted for 2013.

Union - +4.5

Cost - $404,850

In 2013 our FTE is forecasted to increase by the following positions,

- IFRS/Accounting Analyst- Jan 1, 2013
- Meter Technician – Jan 1, 2013
- Part Time Regulatory Analyst – Jan 1, 2013
- Purchasing Analyst – Jan 1, 2014
- Customer Service Representative – Jan 1, 2014,

The justification for these 5 positions has been provided in the header **2013 Test Year OM&A Costs** within this Exhibit on page 5, Schedule 1.

OMERS 2013 Contribution Rates and Plan Changes Announced

On June 28, 2012, the OMERS Sponsors Corporation (SC) approved changes to the OMERS Primary Pension Plan (OMERS Plan) and Retirement Compensation Arrangement (RCA), contribution rate increases were set for 2013, the second increase as part of a three-year strategy announced in 2011; and

- The funding flexibility of the RCA was enhanced.
- The SC also made the decision to file the December 2011 OMERS Primary Plan valuation.

Contributions to the OMERS Plan are made by members and matched by employers. Along with investment earnings, contributions provide members with lifetime retirement income. Contribution rate changes are effective with the first full pay in 2013.

Contribution rates for normal retirement age 65 members

- On earnings up to CPP earnings limit*: 2012 is 7.4%; **2013 is 8.3%**
- On earnings over CPP earnings limit*: 2012 is 10.7%; **2013 is 12.8%**

Contribution rates for normal retirement age 60 members

- On earnings up to CPP earnings limit*: 2012 is 8.9%; **2013 is 9.4%**
- On earnings over CPP earnings limit*: 2012 is 14.1%; **2013 is 13.9%**

*CPP earnings limit (Year's Maximum Pensionable Earnings or YMPE) in 2012 is $50,100; the limit in 2013 will be higher. OMERS members pay a lower rate of contributions on earnings up to the YMPE because OMERS and the CPP are designed to work together to provide pension benefits.

PURCHASE OF PRODUCTS AND SERVICES FROM NON-AFFILIATES:

IHDSL purchases many services and products from third parties. Tables 2.26, 2.27 and 2.28 disclose the expenditures by vendor where the annual amount exceeded $50,000 per year, for the years 2009, 2010 and 2011, respectively.

A copy of IHDSL's procurement policy has been provided in Appendix B and IHDSL has followed this policy in the past and will continue to do so.

Tables 2.26 thru 2.28 contain the historical Non-Affiliate Supplier information including Vendor, total amount of goods or services purchased and the procurement method used.

Table 2.26: 2009 Non-Affiliate Suppliers

2009 Non Affilate Purchases

Vendor Name	Amount	Product or Service	Procurement Method
Aecon Utilities	1,014,046	Pole Line Construction	Tender
Automated Solutions Inc	51,100	GIS software development maintence	Market Rate
BDO Canada	79,603	Great Plains software support	Market Rate
Canada Post	92,615	Postage	Market Rate
Canadian Electrical Services	138,778	Transformers	Market Rate
Composite Power Group	141,755	Switchgear	Market Rate
Engineering Tech Support Services	112,960	Engineering services	Market Rate
Fines Ford Lincoln	81,670	Vehicles	Market Rate
Guelph Utility Pole Co	218,121	Poles	Market Rate
Harris	127,024	Software maintenance	Market Rate
HD Supply Utilities	407,454	Pole line materials/transformers/wire	Market Rate
K-Line	1,606,341	Pole line contruction	Tender
KTI LTD	1,212,179	Smart meters & tower	Tender
Lakeside Tree Experts	141,417	Tree trimming	Tender
Manulife	137,775	Benefit insurance	Market Rate
Moloney Electric Inc	57,748	Transformers	Market Rate
Noramco Wire & Cable	114,216	Conductor	Market Rate
Olameter Inc	231,565	Meter reading services	Market Rate
Omers	117,113	Pension	Market Rate
PC Applications	78,063	SCADA support services	Market Rate
S & C Electric Canada Ltd	431,971	Switchgear	Market Rate

Table 2.27: 2010 Non-Affiliate Suppliers

2010 Non Affilate Purchases

Vendor Name	Amount	Product or Service	Procurement Method
Aecon Utilities	365,324	Pole Line Construction	Tender
Bel Volt Sales Ltd	51,227	Pipeline hardware	Market Rate
BDO Canada	112,125	Great Plains software support	Market Rate
Canada Post	93,696	Postage	Market Rate
Engineering Tech Support Services	147,947	Engineering services	Market Rate
Guelph Utility Pole Co	280,460	Poles	Market Rate
Harris	70,636	Software maintenance	Market Rate
HD Supply Utilities	429,906	Pole line materials/transformers/wire	Market Rate
K-Line Maintenance	740,842	Pole Line Construction	Tender
KTI LTD	411,120	Smart meters	Tender
Lakeside Tree Experts	85,013	Tree trimming	Tender
Laprairie Incorporated	155,621	Switchgear	Market Rate
Manulife	140,027	Benefit insurance	Market Rate
Mearie Group	201,325	Liability & property insurance	Market Rate
Ministry of Finance	89,749	Special purpose charge	
Noramco Wire & Cable	159,452	Conductor	Market Rate
Olameter Inc	200,093	Meter reading services	Market Rate
Omers	139,572	Pension	Market Rate
Posi-Plus	257,100	Vehicles Aerial Devices	Tender
Sensus Canada	110,332	Smart meters and services	Tender
Shepherds Utility Equipment	80,053	Tools and supplies	Market Rate
Somerville	2,628,097	Pole Line Construction	Tender
Sturdy Power Lines Ltd	628,336	Pole Line Construction	Tender
Wajx Equipment	84,877	Vehicles Aerial Devices	Market Rate

Table 2.28: 2011 Non-Affiliate Suppliers

2011 Non Affilate Purchases

Vendor Name	Amount	Product or Service	Procurement Method
Aecon Utilities	223,615	Pole Line Construction	Tender
BDO Canada	56,705	Great Plains software support	Market Rate
Canada Post	106,193	Postage	Market Rate
Canada Power Products	127,607	Switchgear	Market Rate
Graham Partners	51,440	Legal service	Market Rate
Guelph Utility Pole Co	144,234	Poles	Market Rate
Harris	78,038	Software maintenance	Market Rate
HD Supply Utilities	448,592	Pole line materials/transformers/wire	Market Rate
Lineman's Testing Lab	54,443	Safety testing	Market Rate
Manulife	189,189	Benefit insurance	Market Rate
Mearie Group	67,959	Liability & property insurance	Market Rate
Noramco Wire & Cable	60,873	Conductor	Market Rate
Olameter Inc	110,125	Meter reading services	Market Rate
Omers	197,305	Pension	Market Rate
PC Applications	75,957	SCADA support services	Market Rate
Power Edge Systems Inc	82,384	Computer hardware	Market Rate
Sensus Canada	69,382	Smart meters	Tender
S&C Electric Canada Ltd	140,640	Switchgear	Market Rate
Somerville	691,384	Pole Line Construction	Tender
Sturdy Power Lines Ltd	1,240,589	Pole Line Construction	Tender
Valard Construction	156,523	Construction	Tender
Wajax Equipment	240,578	Vehicles Aerial Devices	Tender
Weller Tree Services	102,143	Tree trimming	Tender

DEPRECIATION, AMORTIZATION AND DEPLETION:

Amortization on capital assets is calculated as follows:

- IHDSL uses the pooling of assets for all fixed assets with the exception of Computer Equipment/Software, Automotive Equipment and Furniture & Equipment. Amortization is calculated on a straight line basis over the estimated remaining useful life of the assets at the end of the previous year plus 50% of the current year capital additions.

- IHDSL's amortization policy has been to take a half-year's amortization on capital additions during the current year. As per OEB guidelines, LDCs are required to use the half-year rule when accounting for amortization expense.

- Depreciation rates are in line with rates set out in the APH. These rates are reflected in the tables that follow.

- Table 4.2.28 below provides a summary of amortization expense for the years 2009 to 2011 Actual, 2012 Bridge Year (CGAAP and MIFRS) and 2013 Test Year (MIFRS).

Table 2.32 – Summary of Amortization Expense

The year-over-year fluctuations in amortization expense (as seen above) are natural based on capital additions, disposal of assets, and assets becoming fully depreciated. The increase for 2012 over 2011 is mainly due to the inclusion of Smart Meters in 2012's rate base.

IHDSL has provided detailed amortization expense calculations using the OEB's methodology and provided a reconciliation to IHDSL's Audited Financial Statement amortization amounts (where applicable) in Tables 2.33 through 2.37 below:

Appendix 2-CE
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2011 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2011 (a)	Less Fully Depreciated (b)		Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2011 Depreciation Expense (h) = (e) / (f)	2011 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (I)	Variance [2] (m) = (h) - (I)
1611	Computer Software (Formally known as Account 1925)	$ 1,032,751	$ 823,485	80%	$ 209,267	$ 73,245	$ 245,889	3.00	33.33%	$ 81,963.00	$ 81,963.00	$ -
1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1805	Land	$ 273,770			$ 273,770	$ -	$ 273,770			$ -	$ -	$ -
1806	Land rights	$ 988,464	$ 230,654	23%	$ 757,810	$ 1,981	$ 758,800	50.00	2.00%	$ 15,176.00	$ 15,176.00	$ 0.00
1808	Buildings	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1810	Leasehold Improvements	$ 86,252	$ -		$ 86,252	$ -	$ 86,252	25.00	4.00%	$ 3,450.08	$ 3,450.00	$ 0.08
1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 4,431,283	$ 1,376,999	31%	$ 3,054,285	$ 152,331	$ 3,130,450	25.00	4.00%	$ 125,218.00	$ 125,218.00	$ -
1825	Storage Battery Equipment	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 8,331,730	$ 99,685	1%	$ 8,232,045	$ 935,010	$ 8,699,550	25.00	4.00%	$ 347,982.00	$ 347,982.00	$ -
1835	Overhead Conductors & Devices	$ 12,001,819	$ 5,518,804	46%	$ 6,483,016	$1,491,019	$ 7,228,525	25.00	4.00%	$ 289,141.00	$ 289,141.00	$ -
1840	Underground Conduit	$ 1,810,440	$ 112,556	6%	$ 1,697,884	$ 225,131	$ 1,810,450	25.00	4.00%	$ 72,418.00	$ 72,418.00	-$ 0.00
1845	Underground Conductors & Devices	$ 11,561,168	$ 46,545	0%	$ 11,514,623	$ 251,455	$ 11,640,350	25.00	4.00%	$ 465,614.00	$ 465,614.00	$ 0.00
1850	Line Transformers	$ 8,135,538	$ 53,005	1%	$ 8,082,533	$ 487,484	$ 8,326,275	25.00	4.00%	$ 333,051.00	$ 333,051.00	$ -
1855	Services (Overhead & Underground)	$ 3,711,507	$ 2,228	0%	$ 3,709,279	$ 306,192	$ 3,862,375	25.00	4.00%	$ 154,495.00	$ 154,495.00	$ -
1860	Meters	$ 187,025	$ -	0%	$ 187,025	$ 10,308	$ 192,179	25.00	4.00%	$ 7,687.16	$ 27,067.00	-$ 19,379.84
1860	Meters (Smart Meters)	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1875	Street Lighting	$ 7,646		0%	$ 7,646	$ -	$ 7,646	25.00	4.00%	$ 305.84	$ 305.00	$ 0.84
1905	Land	$ 201,049		0%	$ 201,049	$ -	$ 201,049	-		$ -	$ -	$ -
1908	Buildings & Fixtures	$ 737,784		0%	$ 737,784	$ 1,847	$ 738,708	25.00	4.00%	$ 29,548.30	$ 29,548.00	$ 0.30
1910	Leasehold Improvements	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 294,399	$ 151,387	51%	$ 143,012	$ 14,256	$ 150,140	10.00	10.00%	$ 15,014.00	$ 15,014.00	$ -
1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 872,059	$ 565,158	65%	$ 306,901	$ 16,388	$ 315,095	5.00	20.00%	$ 63,019.00	$ 63,019.00	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1930	Transportation Equipment	$ 836,916	$ -	0%	$ 836,916	$ 297,131	$ 985,482	5.00	20.00%	$ 197,096.30	$ 220,718.00	-$ 23,621.70
1935	Stores Equipment	$ 30,118	$ 11,481	38%	$ 18,637	$ 1,706	$ 19,490	10.00	10.00%	$ 1,949.00	$ 1,949.00	$ -
1940	Tools, Shop & Garage Equipment	$ 469,385	$ 156,809	33%	$ 312,576	$ 58,448	$ 341,800	10.00	10.00%	$ 34,180.00	$ 34,180.00	$ -
1945	Measurement & Testing Equipment	$ 23,690	$ 3,844	16%	$ 19,847	$ 9,307	$ 24,500	10.00	10.00%	$ 2,450.00	$ 2,450.00	$ -
1950	Power Operated Equipment	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1955	Communications Equipment	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1980	System Supervisor Equipment	$ 1,324,906			$ 1,324,906	$ 82,487	$ 1,366,150	15.00	6.67%	$ 91,076.63	$ 91,077.00	-$ 0.37
1985	Miscellaneous Fixed Assets	$ -			$ -	$ -	$ -			$ -	$ -	$ -
1995	Contributions & Grants	-$ 7,193,539	-$ 188,568		-$ 7,004,972	-$ 521,407	-$ 7,265,675	25.00	4.00%	-$ 290,627.00	-$ 290,627.00	$ -
etc.					$ -		$ -			$ -		$ -
					$ -		$ -			$ -		$ -
	Total	$ 50,156,160	$ 8,964,071	18%	$ 41,192,089	$3,894,319	$ 43,139,249			$2,040,207.32	$ 2,083,208.00	-$ 43,000.68

Notes:

Appendix 2-CF
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2012 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2012 (a)	Less Fully Depreciated (b)		Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2012 Depreciation Expense (h) = (e) / (f)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 363,599	$ 162,914	-$ 660,571	$ 200,685	$ 282,150	$ 341,760	3.00	33.33%	$ 113,920.00	$ 113,920.00	$ -
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1805	Land	$ 273,770	$ -	$ -	$ 273,770	$ 465,000	$ 506,270	-	0.00%	$ -	$ -	$ -
1806	Land rights	$ 982,703	$ 239,103	$ 8,449	$ 743,600	$ -	$ 743,600	50.00	2.00%	$ 14,872.00	$ 14,872.00	$ 0.00
1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	$ 86,252	$ 3,452	$ 3,452	$ 82,800	$ -	$ 82,800	25.00	4.00%	$ 3,312.00	$ 3,312.00	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 4,358,561	$ 1,353,335	-$ 23,664	$ 3,005,226	$ 35,448	$ 3,022,950	25.00	4.00%	$ 120,918.00	$ 120,918.00	$ -
1825	Storage Battery Equipment	$ -	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 9,077,888	$ 726,325	$ 626,640	$ 8,351,564	$1,172,023	$ 8,937,575	25.00	4.00%	$ 357,503.00	$ 357,503.00	$ -
1835	Overhead Conductors & Devices	$13,192,946	$ 6,253,571	$ 734,767	$ 6,939,376	$1,314,249	$ 7,596,500	25.00	4.00%	$ 303,860.00	$ 303,860.00	$ -
1840	Underground Conduit	$ 2,035,571	$ 297,546	$ 184,991	$ 1,738,025	$ 37,200	$ 1,756,625	25.00	4.00%	$ 70,265.00	$ 70,265.00	-$ 0.00
1845	Underground Conductors & Devices	$11,721,156	$ 546,406	$ 499,861	$ 11,174,750	$ 454,700	$ 11,402,100	25.00	4.00%	$ 456,084.00	$ 456,084.00	$ 0.00
1850	Line Transformers	$ 8,602,786	$ 609,566	$ 556,561	$ 7,993,220	$ 545,110	$ 8,265,775	25.00	4.00%	$ 330,631.00	$ 330,631.00	$ -
1855	Services (Overhead & Underground)	$ 4,017,136	$ 309,264	$ 307,036	$ 3,707,873	$ 207,405	$ 3,811,575	25.00	4.00%	$ 152,463.00	$ 152,463.00	$ -
1860	Meters	$ 287,258	$ -	$ -	$ 287,258	$ -	$ 287,258	25.00	4.00%	$ 11,490.32	$ 11,490.32	$ -
1860	Meters (Smart Meters)	$ 2,162,281	$ -	$ -	$ 2,162,281	$ 74,240	$ 2,199,401	15.00	6.67%	$ 146,626.73	$ 146,621.68	$ 5.05
1875	Street Lighting	$ 7,646	$ 7,646	$ 7,646	$ -	$ -	$ -	25.00	4.00%	$ -	$ -	$ -
1905	Land	$ 201,049	$ -	$ -	$ 201,049	$ -	$ 201,049	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 739,631	$ -	$ -	$ 739,631	$2,025,000	$ 1,752,131	25.00	4.00%	$ 70,085.24	$ 28,866.00	$ 41,219.24
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 308,655	$ 196,045	$ 44,658	$ 112,610	$ 25,500	$ 125,360	10.00	10.00%	$ 12,536.00	$ 12,536.00	$ -
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 515,306	$ 263,231	-$ 301,927	$ 252,075	$ 122,500	$ 313,325	5.00	20.00%	$ 62,665.00	$ 62,665.00	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ 1,174,196		$ -	$ 1,174,196	$ -	$ 1,174,196	7.35	13.61%	$ 159,754.56	$ 159,800.00	-$ 45.44
1935	Stores Equipment	$ 31,824	$ 14,284	$ 2,803	$ 17,540	$ 4,000	$ 19,540	10.00	10.00%	$ 1,954.00	$ 1,954.00	$ -
1940	Tools, Shop & Garage Equipment	$ 487,684	$ 180,064	$ 23,255	$ 307,620	$ 27,000	$ 321,120	10.00	10.00%	$ 32,112.00	$ 32,112.00	$ -
1945	Measurement & Testing Equipment	$ 32,997	$ 10,937	$ 7,094	$ 22,060	$ 8,500	$ 26,310	10.00	10.00%	$ 2,631.00	$ 2,631.00	$ -
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 1,407,393	$ 132,313	$ 132,313	$ 1,275,080	$ 367,850	$ 1,459,005	15.00	6.67%	$ 97,267.00	$ 97,267.00	$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	-$ 7,714,946	-$ 739,898	-$ 551,331	-$ 6,975,048	-$1,083,954	-$ 7,517,025	25.00	4.00%	-$ 300,681.00	-$ 300,681.00	$ -
etc.					$ -		$ -		0.00%	$ -		$ -
					$ -		$ -		0.00%	$ -		$ -
	Total	$54,353,342	$ 10,566,102		$ 43,787,240	$6,083,921	$ 46,829,200			$ 2,220,268.86	$ 2,179,090.00	$ 41,178.86

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Appendix 2-CG
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2012 MIFRS

Account	Description	Opening NBV as at Jan 1, 2012 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2012 Depreciation Expense (k) = (j) + (h)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2012 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2012 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 119,195	$ 282,150	1.78	3.00	33.33%	$ 66,895	$ 47,025	$ 113,920	$ 113,920	-$ 0	$ 94,050	$ 32,550	$ 128,395
1612	Land Rights (Formally known as Account 1906)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1805	Land	$ 273,770	$ 465,000			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1806	Land rights	$ 424,717	$ -	28.56	50.00	2.00%	$ 14,872	$ -	$ 14,872	$ 14,872	$ 0	$ -	$ 297	$ 14,575
1808	Buildings	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ 51,752	$ -	15.63	25.00	4.00%	$ 3,312	$ -	$ 3,312	$ 3,312	$ 0	$ -		$ 3,312
1815	Transformer Station Equipment >50 kV	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 2,035,685	$ 35,448	22.51	40.00	2.50%	$ 90,435	$ 443	$ 90,878	$ 90,878	-$ 0	$ 886		$ 91,321
1825	Storage Battery Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 4,791,235	$ 1,172,023	27.54	45.00	2.22%	$ 173,990	$ 13,022	$ 187,013	$ 187,013	-$ 0	$ 26,045		$ 200,035
1835	Overhead Conductors & Devices	$ 5,716,025	$ 1,314,249	41.88	60.00	1.67%	$ 136,486	$ 10,952	$ 147,438	$ 147,438	-$ 0	$ 21,904		$ 158,390
1840	Underground Conduit	$ 1,547,804	$ 37,200	32.06	40.00	2.50%	$ 48,279	$ 465	$ 48,744	$ 48,744	$ 0	$ 930		$ 49,209
1845	Underground Conductors & Devices	$ 7,382,140	$ 454,700	23.78	40.00	2.50%	$ 310,409	$ 5,684	$ 316,093	$ 316,093	$ 0	$ 11,368		$ 321,777
1850	Line Transformers	$ 3,014,840	$ 545,110	15.09	40.00	2.50%	$ 199,830	$ 6,814	$ 206,644	$ 206,644	$ 0	$ 13,628		$ 213,458
1855	Services (Overhead & Underground)	$ 2,259,956	$ 207,405	29.09	50.00	2.00%	$ 77,677	$ 2,074	$ 79,751	$ 79,751	-$ 0	$ 4,148		$ 81,825
1860	Meters	$ 220,222	$ -	19.17	25.00	4.00%	$ 11,490	$ -	$ 11,490	$ 11,490	-$ 0	$ -		$ 11,490
1860	Meters (Smart Meters)	$ 1,834,786	$ 74,240	12.73	15.00	6.67%	$ 144,147	$ 2,475	$ 146,621	$ 146,622	-$ 0	$ 4,949		$ 149,096
1875	Street Lighting	$ 4,976	$ -		-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1905	Land	$ 201,049	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 465,719	$ 25,000	16.28	50.00	2.00%	$ 28,616	$ 250	$ 28,866	$ 28,866	-$ 0	$ 500		$ 29,116
1910	Leasehold Improvements	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 76,007	$ 25,500	6.75	10.00	10.00%	$ 11,261	$ 1,275	$ 12,536	$ 12,536	$ 0	$ 2,550		$ 13,811
1915	Office Furniture & Equipment (5 years)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 115,225	$ 122,500	2.29	5.00	20.00%	$ 50,415	$ 12,250	$ 62,665	$ 62,665	-$ 0	$ 24,500	$ 12,533	$ 62,382
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 714,062	$ -	4.47	5.00	20.00%	$ 159,800	$ -	$ 159,800	$ 159,800	$ 0	$ -		$ 159,800
1935	Stores Equipment	$ 13,652	$ 4,000	7.79	10.00	10.00%	$ 1,754	$ 200	$ 1,954	$ 1,954	-$ 0	$ 400		$ 2,154
1940	Tools, Shop & Garage Equipment	$ 299,447	$ 27,000	9.73	10.00	10.00%	$ 30,762	$ 1,350	$ 32,112	$ 32,112	$ 0	$ 2,700		$ 33,462
1945	Measurement & Testing Equipment	$ 18,771	$ 8,500	8.51	10.00	10.00%	$ 2,206	$ 425	$ 2,631	$ 2,631	-$ 0	$ 850		$ 3,056
1950	Power Operated Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 618,334	$ 367,850	7.27	15.00	6.67%	$ 85,005	$ 12,262	$ 97,267	$ 97,267	-$ 0	$ 24,523		$ 109,528
1985	Miscellaneous Fixed Assets	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 6,144,728	-$ 1,083,954	29.28	35.00	2.86%	-$ 209,897	-$ 15,485	-$ 225,382	-$ 225,382	$ 0	-$ 30,970		-$ 240,867
etc.						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
	Total	$ 26,054,641.00	$ 4,083,921.00				$ 1,437,744	$ 101,481	$ 1,539,226	$ 1,539,226	$ 0	$ 202,961	$ 45,380	$ 1,595,325

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Appendix 2-CH
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2013 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2013 Depreciation Expense [1] (h)=2012 Full Year Depreciation + ((d)*0.5)/(f)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	278,500	3.00	33.33%	$ 174,811	$ 174,811	$ 0
1612	Land Rights (Formally known as Account 1906)	-	-	0.00%	$ -	$ -	$ -
1805	Land	-	-	0.00%	$ -	$ -	$ -
1806	Land rights	-	-	0.00%	$ 14,575	$ 14,575	$ 0
1808	Buildings	-	-	0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	-	25.00	4.00%	$ 3,312	$ 3,312	$ 0
1815	Transformer Station Equipment >50 kV	-	-	0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	194,422	40.00	2.50%	$ 93,751	$ 93,752	-$ 1
1825	Storage Battery Equipment	-	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	918,153	45.00	2.22%	$ 210,237	$ 210,238	-$ 1
1835	Overhead Conductors & Devices	1,123,543	60.00	1.67%	$ 167,753	$ 167,753	-$ 0
1840	Underground Conduit	38,205	40.00	2.50%	$ 49,687	$ 49,686	$ 1
1845	Underground Conductors & Devices	157,573	40.00	2.50%	$ 323,747	$ 323,746	$ 1
1850	Line Transformers	649,500	40.00	2.50%	$ 221,577	$ 221,577	-$ 0
1855	Services (Overhead & Underground)	216,912	50.00	2.00%	$ 83,994	$ 83,994	-$ 0
1860	Meters	-	25.00	4.00%	$ 11,490	$ 11,490	$ 0
1860	Meters (Smart Meters)	116,170	15.00	6.67%	$ 152,968	$ 152,968	$ 0
1875	Street Lighting	-	-	0.00%	$ -	$ -	$ -
1905	Land	-	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	7,127,500	50.00	2.00%	$ 100,391	$ 100,391	-$ 0
1910	Leasehold Improvements	-	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	35,000	10.00	10.00%	$ 15,561	$ 15,561	$ 0
1915	Office Furniture & Equipment (5 years)	-	-	0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	128,000	5.00	20.00%	$ 75,182	$ 75,182	-$ 0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	-	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	-	-	0.00%	$ -	$ -	$ -
1930	Transportation Equipment	110,000	5.00	20.00%	$ 170,800	$ 170,800	$ 0
1935	Stores Equipment	4,200	10.00	10.00%	$ 2,364	$ 2,364	-$ 0
1940	Tools, Shop & Garage Equipment	20,000	10.00	10.00%	$ 34,462	$ 34,462	$ 0
1945	Measurement & Testing Equipment	19,000	10.00	10.00%	$ 4,006	$ 4,006	-$ 0
1950	Power Operated Equipment	-	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	-	-	0.00%	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	-	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	-	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	-	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	266,697	15.00	6.67%	$ 118,418	$ 118,418	$ 0
1985	Miscellaneous Fixed Assets	-	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	- 382,523	35.00	2.86%	-$ 246,332	-$ 246,332	$ 0
etc.				0.00%	$ -		$ -
				0.00%	$ -		$ -
	Total	$ 11,020,852			$ 1,782,754	$ 1,782,754	-$ 0
	Depreciation expense adjustment resulting from amortization of Account 1575				-$ 639,864		
	Total Depreciation expense to be included in the test year revenue requirement				**$ 1,142,890**		

Table 2.38 - Amortization Expense for 2013 Test Year (MIFRS)

Year 2013

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 645,749	$ 278,500		$ 924,249	-$ 352,902	-$ 174,811		-$ 527,713	$ 396,536
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ 738,770			$ 738,770	$ -			$ -	$ 738,770
CEC	1806	Land Rights		$ 982,703			$ 982,703	-$ 572,858	-$ 14,575		-$ 587,433	$ 395,270
47	1808	Buildings		$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ 86,252			$ 86,252	-$ 37,812	-$ 3,312		-$ 41,124	$ 45,128
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 4,394,009	$ 194,422		$ 4,588,431	-$ 2,413,754	-$ 93,752		-$ 2,507,506	$ 2,080,925
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 10,149,911	$ 918,153	-$ 105,000	$ 10,963,064	-$ 4,388,666	-$ 210,238	$ 89,250	-$ 4,509,654	$ 6,453,410
47	1835	Overhead Conductors & Devices		$ 14,357,195	$ 1,123,543	-$ 157,500	$ 15,323,238	-$ 7,496,859	-$ 167,753	$ 133,875	-$ 7,530,737	$ 7,792,501
47	1840	Underground Conduit		$ 2,072,771	$ 38,205		$ 2,110,976	-$ 536,511	-$ 49,686		-$ 586,197	$ 1,524,779
47	1845	Underground Conductors & Devices		$ 12,125,856	$ 157,573	-$ 52,500	$ 12,230,929	-$ 4,612,609	-$ 323,746	$ 44,625	-$ 4,891,730	$ 7,339,199
47	1850	Line Transformers		$ 9,137,896	$ 649,500	-$ 10,500	$ 9,776,896	-$ 5,786,090	-$ 221,577	$ 8,925	-$ 5,998,742	$ 3,778,154
47	1855	Services (Overhead & Underground)		$ 4,224,541	$ 216,912		$ 4,441,453	-$ 1,836,931	-$ 83,994		-$ 1,920,925	$ 2,520,528
47	1860	Meters		$ 287,258			$ 287,258	-$ 78,526	-$ 11,490		-$ 90,016	$ 197,242
47	1860	Meters (Smart Meters)		$ 2,236,521	$ 116,170		$ 2,352,691	-$ 474,117	-$ 152,968		-$ 627,085	$ 1,725,606
47	1875	Street Lighting		$ -			$ -	$ -			$ -	$ -
N/A	1905	Land		$ 201,049			$ 201,049	$ -			$ -	$ 201,049
47	1908	Buildings & Fixtures		$ 2,764,631	$ 5,127,500		$ 7,892,131	-$ 302,778	-$ 100,391		-$ 403,169	$ 7,488,962
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 334,155	$ 35,000		$ 369,155	-$ 245,184	-$ 15,561		-$ 260,745	$ 108,410
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 637,806	$ 128,000		$ 765,806	-$ 462,746	-$ 75,182		-$ 537,928	$ 227,878
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 1,174,196	$ 110,000		$ 1,284,196	-$ 619,934	-$ 170,800		-$ 790,734	$ 493,462
8	1935	Stores Equipment		$ 35,824	$ 4,200		$ 40,024	-$ 20,126	-$ 2,364		-$ 22,490	$ 17,534
8	1940	Tools, Shop & Garage Equipment		$ 514,684	$ 20,000		$ 534,684	-$ 220,349	-$ 34,462		-$ 254,811	$ 279,873
8	1945	Measurement & Testing Equipment		$ 41,497	$ 19,000		$ 60,497	-$ 16,857	-$ 4,006		-$ 20,863	$ 39,634
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ 1,775,243	$ 266,697		$ 2,041,940	-$ 886,326	-$ 118,418		-$ 1,004,744	$ 1,037,196
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 8,798,900	-$ 382,523		-$ 9,181,423	$ 1,795,600	$ 246,332		$ 2,041,932	-$ 7,139,491
	etc.			$ -			$ -				$ -	$ -
				$ -								
		Total		**$ 60,119,617**	**$ 9,020,852**	**-$ 325,500**	**$ 68,814,969**	**-$ 29,566,335**	**-$ 1,782,754**	**$ 276,675**	**-$ 31,072,414**	**$ 37,742,555**
												$ 37,817,555

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 170,800
Stranded Meters	
Net Depreciation	-$ 1,611,954

TAX CALCULATIONS:

Table 3.1 below provides a summary of 2009 Approved, the 2009, 2010, 2011 Actual, and the 2012 Bridge Year (CGAAP and MIFRS) and 2013 Test Year (MIFRS) income tax estimate using rates prescribed by the OEB in IHDSL's 2011 IRM rate decision and order. A copy of IHDSL's 2011 annual federal and provincial tax return has been provided as Appendix B to this exhibit.

Table 3.1 – Summary of Income & Capital Taxes 2009 to 2013

Description	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Test Year
Income Taxes – Current	464,016	431,580	395,850	367,231	25,788
Total Taxes	**464,016**	**431,580**	**395,850**	**367,231**	**25,788**

IHDSL's detailed tax calculations using the most recent tax rates are provided in Table 3.2.

Table 3.2 – Detailed Tax Calculations for 2009 to 2013

IHDSL Corporate Tax Rates		
Corporate Tax Rates for Tax Year:	2012 Bridge	2013 Test
Federal Income Tax	15.00%	15.00%
Ontario Income Tax	11.25%	10.25%
Combined Income Tax	26.25%	25.25%
Small Business Threshold	500,000	500,000
Federal Small Business Rate	11.00%	11.00%
Ontario Small Business Rate	4.50%	4.50%
Combined Small Business Rate	15.50%	15.50%
Small Business Credit	$33,750	$28,750

CAPITAL COST ALLOWANCE:

IHDSL is providing Capital Cost Allowance continuity schedules for the 2012 Bridge Year (Tables 3.3 & 3.4) and the 2013 Test Year (Tables 3.5 & 3.6) as follows:

Table 3.3 – 2012 CCA / UCC Continuity Schedule

CCA Continuity Schedule (2012)

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Proceeds of 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	14,160,463	0	0	14,160,463	0	0	14,160,463	0	14,160,463	4%	566,419	13,594,044
2	Distribution System - pre 1988		0	0	0	0	0	0	0	0	6%	0	0
6	Buildings - after 1990		0	0	0	0	0	0	0	0	10%	0	0
8	General Office/Stores Equip	733,538	0	0	733,538	65,000	0	798,538	32,500	766,038	20%	153,208	645,330
10	Computer Hardware/ Vehicles	679,501	0	0	679,501	122,500	0	802,001	61,250	740,751	30%	222,225	579,776
10.1	Certain Automobiles		0	0	0	0	0	0	0	0	30%	0	0
12	Computer Software	36,623	0	0	36,623	282,150	0	318,773	141,075	177,698	100%	177,698	141,075
3	Buildings - pre 1990		0	0	0	0	0	0	0	0	5%	0	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
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	5,592	0	0	5,592	0	0	5,592	0	5,592	45%	2,516	3,076
50	Computers & Systems Hardware acq'd post Mar 19/07	17,532	0	0	17,532	0	0	17,532	0	17,532	55%	9,643	7,889
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	15,678,237			15,678,237	5,149,271	310,000	20,517,508	2,574,636	17,942,873	8%	1,435,430	19,082,078
	SUB-TOTAL - UCC	**31,311,486**	**0**	**0**	**31,311,486**	**5,618,921**	**310,000**	**36,620,407**	**2,809,461**	**33,810,947**		**2,567,138**	**34,053,269**
CEC	Goodwill		0	0	0								
CEC	Land Rights	313,977	0	0	313,977								
CEC	FMV Bump-up		0	0	0								
	SUB-TOTAL - CEC	**313,977**	**0**	**0**	**313,977**								

Table 3.4 – 2012 CEC Continuity Schedule

Cumulative Eligible Capital Calculation 2012				
Cumulative Eligible Capital				313,977
Additions:				
Cost of Eligible Capital Property Acquired during the year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
			0	313,977
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				313,977
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	313,977
Cumulative Eligible Capital Balance				313,977
CEC Deduction	7%			21,978
Cumulative Eligible Capital - Closing Balance				291,999

Table 3.5 – 2013 CCA / UCC Continuity Schedule

CCA Continuity Schedule (2013)

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Proceeds of 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	13,594,044	0	0	13,594,044	0	0	13,594,044	0	13,594,044	4%	543,762	13,050,283
2	Distribution System - pre 1988	0	0	0	0	0	0	0	0	0	6%	0	0
6	Buildings - after 1990	0	0	0	0	0	0	0	0	0	10%	0	0
8	General Office/Stores Equip	645,330	0	0	645,330	78,200	0	723,530	39,100	684,430	20%	136,886	586,644
10	Computer Hardware/ Vehicles	579,776	0	0	579,776	238,000	0	817,776	119,000	698,776	30%	209,633	608,143
10.1	Certain Automobiles	0	0	0	0	0	0	0	0	0	30%	0	0
12	Computer Software	141,075	0	0	141,075	278,500	0	419,575	139,250	280,325	100%	280,325	139,250
3	Buildings - pre 1990	0	0	0	0	0	0	0	0	0	5%	0	0
		0	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	3,076	0	0	3,076	0	0	3,076	0	3,076	45%	1,384	1,692
50	Computers & Systems Hardware acq'd post Mar 19/07	7,889	0	0	7,889	0	0	7,889	0	7,889	55%	4,339	3,550
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	19,082,078			19,082,078	8,426,152	325,500	27,182,730	4,213,076	22,969,654	8%	1,837,572	25,345,158
	SUB-TOTAL - UCC	34,053,269	0	0	34,053,269	9,020,852	325,500	42,748,621	4,510,426	38,238,195		3,013,901	39,734,720
						0	0						
CEC	Goodwill	0	0	0	0								
CEC	Land Rights	0	0	0	0								
CEC	FMV Bump-up	0	0	0	0								
	SUB-TOTAL - CEC	0	0	0	0								

Table 3.6 - 2013 CEC Continuity Schedule

Cumulative Eligible Capital Calculation 2013

Cumulative Eligible Capital				291,999
Additions:				
Cost of Eligible Capital Property Acquired during the year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
			0	291,999
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				291,999
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	291,999
Cumulative Eligible Capital Balance				291,999
CEC Deduction	7%			20,440
Cumulative Eligible Capital - Closing Balance				271,559

MIFRS – IMPACT ON OM&A

Conversion to Modified International Financial Reporting Standards (MIFRS)

International Accounting Standard 16 (IAS 16) – Property, Plant and Equipment (PP&E), states the cost of an item of PP&E includes any costs that are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. IAS 16 does not define the term "directly attributable". The specific facts and circumstances surrounding the nature of the costs and the activity associated with it must be considered to determine if it is directly attributable to an item of PP&E. Where Canadian GAAP allowed for the capitalization of general and administrative overhead, MIFRS does not.

In order to allocate costs between operating expenses and capital expenses, IHDSL utilizes payroll and vehicle maintenance burdens.

In reviewing each of these burdens IHDSL has identified there are no changes to be made for capitalization under MIFRS.

MIFRS – IMPACT ON DEPRECIATION

IAS 16 requires each part of an item of PP&E with a cost that is significant in relation to the total cost of the time to be depreciated separately. In addition IAS 16 requires that entities perform a review of assets' useful lives, depreciation methods and residual values on an annual basis.

The Board commissioned a depreciation study to assist electricity distributors in their transition to IFRS. In the Report of the Board, Transition to International Financial Reporting Standards, (EB-2009-0408) the Board stated:

> "While utilities remain solely responsible for complying with financial reporting requirements, the Board notes that a generic depreciation study could assist utilities with IFRS compliance in addition to providing considerable regulatory benefits. The study should provide a good starting point for the determination of service lives for distribution assets that may be both acceptable to the Board and useful for financial reporting purposes. Distributors will remain responsible for review and updates of the service lives for their particular assets for financial reporting and regulatory requirements."

IHDSL has reviewed the useful life of its assets with the aid of the Asset Depreciation Study by Kinetrics (Kinetrics Report). Overall, the useful lives have been extended causing depreciation to be reduced in the 2013 Test year by $639,864.

As discussed previously, IHDSL retained BDO Dunwoody, LLP to provide assistance in the transition of financial records from CGAAP to IFRS which included the assignment of useful lives to the asset base.

The new levels of componentization were applied by IHDSL January 1, 2011, and the corresponding updated useful lives will be applied beginning January 1, 2012.

IHDSL has provided the Capital Cost Allowance continuity schedules for the 2012 Bridge Year (IFRS) under Tables 4.4 & 4.5, and the 2013 Test Year (IFRS) under Tables 4.6 & 4.7.

Table 4.4 – CCA Continuity Schedule 2012 (MIFRS)

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	25,442,024			25,442,024	0	0	25,442,024	0	25,442,024	0	1,017,681	24,424,343
2	Distribution System - pre 1988				0	0	0	0	0	0	0	0	0
6	Buildings (No footings below ground)				0	0	0	0	0	0	0	0	0
8	General Office/Stores Equip	1,150,803			1,150,803	58,000	89,504	1,119,299	29,000	1,090,299	0	218,060	901,239
10	Computer Hardware/ Vehicles	253,201			253,201	470,000	0	723,201	235,000	488,201	0	146,460	576,741
10.1	Certain Automobiles				0	0	0	0	0	0	0	0	0
12	Computer Software	0			0	27,000	0	27,000	13,500	13,500	1	13,500	13,500
3		2,684,222			2,684,222	0	0	2,684,222	0	2,684,222	0	134,211	2,550,011
					0	0	0	0	0	0		0	0
13 3	Lease # 3				0	0	0	0	0	0		0	0
13 4	Lease # 4				0	0	0	0	0	0		0	0
14	Franchise				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
43.1	Certain Energy-Efficient Electrical Generating Equipment				0	0	0	0	0	0	0	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	16,219			16,219	0	0	16,219	0	16,219	0	7,299	8,920
50	Computers & Systems Hardware acq'd post Mar 19/07	25,207			25,207	0	0	25,207	0	25,207	1	13,864	11,343
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				0	0	0	0	0	0	0	0	0
47	Distribution System - post 22-Feb-2005	24,364,877			24,364,877	2,811,043	0	27,175,920	1,405,522	25,770,399	0	2,061,632	25,114,288
	SUB-TOTAL - UCC	**53,936,553**	**0**	**0**	**53,936,553**	**3,366,043**	**89,504**	**57,213,092**	**1,683,022**	**55,530,070**		**3,612,706**	**53,600,385**
CEC	Goodwill		0	0	0								
CEC	Land Rights		0	0	0								
CEC	FMV Bump-up		0	0	0								
	SUB-TOTAL - CEC	**0**	**0**	**0**	**0**								

Table 4.5 – CEC Continuity Schedule 2012 (MIFRS)

Cumulative Eligible Capital Calculation				
Cumulative Eligible Capital				206,039
Additions:				
Cost of Eligible Capital Property Acquired during the year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
			0	206,039
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				206,039
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	206,039
Cumulative Eligible Capital Balance				206,039
CEC Deduction	7%			14,423
Cumulative Eligible Capital - Closing Balance				191,616

Table 4.6 – CCA Continuity Schedule 2013 (MIFRS)

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	24,424,343	0	0	24,424,343	0	0	24,424,343	0	24,424,343	4%	976,974	23,447,369
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	901,239	0	0	901,239	96,500	0	997,739	48,250	949,489	20%	189,898	807,841
10	Computer Hardware/ Vehicles	576,741	0	0	576,741	80,000	0	656,741	40,000	616,741	30%	185,022	471,718
10.1	Certain Automobiles	0	0	0	0	0	0	0	0	0	30%	0	0
12	Computer Software	13,500	0	0	13,500	142,500	0	156,000	71,250	84,750	100%	84,750	71,250
3		2,550,011	0	0	2,550,011	0	0	2,550,011	0	2,550,011	5%	127,501	2,422,510
		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	8,920	0	0	8,920	0	0	8,920	0	8,920	45%	4,014	4,906
50	Computers & Systems Hardware acq'd post Mar 19/07	11,343	0	0	11,343	0	0	11,343	0	11,343	55%	6,239	5,104
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	25,114,288			25,114,288	3,581,520	0	28,695,808	1,790,760	26,905,048	8%	2,152,404	26,543,404
	SUB-TOTAL - UCC	**53,600,385**	**0**	**0**	**53,600,385**	**3,900,520**	**0**	**57,500,906**	**1,950,260**	**55,550,646**		**3,726,801**	**53,774,105**
						-533,477	0						
CEC	Goodwill	0	0	0	0								
CEC	Land Rights	0	0	0	0								
CEC	FMV Bump-up	0	0	0	0								
	SUB-TOTAL - CEC	**0**	**0**	**0**	**0**								

Table 4.7 – CEC Continuity Schedule 2013 (MIFRS)

Cumulative Eligible Capital Calculation				
Cumulative Eligible Capital				191,616
Additions:				
Cost of Eligible Capital Property Acquired during the year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
			0	191,616
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				191,616
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	191,616
Cumulative Eligible Capital Balance				191,616
CEC Deduction	7%			13,413
Cumulative Eligible Capital - Closing Balance				178,203

APPENDIX A

IHDSL PURCHASING POLICY

Innisfil Hydro Distribution Systems Limited

POLICY AND PROCEDURE MANUAL

Procedure Number:	**TBD**	**Revision Number:**
Title:	**Purchasing Approval Policy**	
Issued by:	Finance	**Approved by:**
Date:	November 30, 2010	**Page: 1 of 2 pages**

PURPOSE AND APPLICABILITY

To prescribe the approval procedure for authorizing major expenditures for repairs, expenditures for tooling, inventory items, etc, legal fees, environmental costs, outside consultants and services, and leases. This policy applies to Innisfil Hydro Distribution Systems Limited and its subsidiaries "(The Company)".

POLICY STATEMENT

It is the policy of the Company that all capitalized and non-capitalized expenditures greater than $100,000 but in the plan, greater than $15,000 not in the plan and leases and contracts having a term longer than one year and a cost of over $75,000 must be approved by the Board of Directors. Leases for equipment must be supported by a lease versus buy analysis. All other expenses to be approved based on the criteria and levels set out below.

PROCEDURE AND RESPONSIBILITY

It is the joint responsibility of both the President and of the Chief Financial Officer to insure that proper approvals for all transactions are received. For transactions exceeding the above criteria, an expense request form (Exhibit A) must be submitted for approval with appropriate attachments explaining: 1) Reason for the proposed expenditure; 2) Detail of profit resulting from proposed expenditure; and 3) quotation comparison. Supplemental Expense Request should include costs incurred to date, projected costs for current Expense Request, and future costs to complete the entire project by major category.

Supplemental requests are to be prepared for each project as soon as it becomes evident that the cost of the project is likely to exceed the approved amount by more than 10%. The word "Supplement" is to be typed on the Expense Request form to distinguish it from a regular Expense Request. Approval will be in the same manner as the original Expense Request.

APPROVAL PROCEDURE & LEVELS

All requests for purchase shall be set up in the purchasing system as requisitions. Requisitions will be approved by the appropriate Manager, validated for appropriateness of expenditure and checked for account coding accuracy.

President or Directors or CFO	Approval of purchase orders not to exceed $15,000
President & Directors or CFO	Approval of purchase orders not to exceed $15,000-$50,000 and minimum 3 quotes
President & Directors or CFO	Approval of purchase orders over $50,000-$75,000 & 3 quotes in writing
Board of Directors	Approval of Capital expenditure and expense projects in excess of $100,000 in plan, exceeding 25% of plan or $15,000 if not in plan

Rental of equipment does not require a purchase order at the time of issue but does require a work order to be associated. The work order will contain the account coding and the invoice will be approved at the time it is received. Work order number must be recorded on third party documentation.

RESPONSIBILITY OF ACCOUNTS PAYABLE

1. Examine purchase order for the appropriate electronic signature(s) of approval.

2. Review receiving documents for matching to invoiced amounts.

3. Code expenses to the correct account classification as per purchase order.

4. Enter the Expense Report into computer system and subsequently control the cheque printing, matching, signing, and delivery of the cheque.

5. Invoices received in the Accounts Payable department which are not in accordance with this policy will return to the appropriate individual for the required adjustment and/or approval.

APPENDIX B

2011 FEDERAL & ONTARIO TAX RETURNS

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2012-12-31

Business number 89242 2817 RC0001

PLEASE RETAIN THIS COPY FOR YOUR FILES

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Revenue Canada. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. A cheque or money order should be made payable to the Receiver General. Payment may be made by cheque or money order payable to the Receiver General either to an authorized financial institution or filed with **the appropriate remittance voucher to the following address:**

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Instalments paid	Cumulative difference	Instalments payable
2012-01-31	27,387			27,387
2012-02-29	27,387			27,387
2012-03-31	27,387			27,387
2012-04-30	27,387			27,387
2012-05-31	27,387			27,387
2012-06-30	27,387			27,387
2012-07-31	27,387			27,387
2012-08-31	27,387			27,387
2012-09-30	27,387			27,387
2012-10-31	27,387			27,387
2012-11-30	27,387			27,387
2012-12-31	27,376			27,376
Total	328,633			328,633

Canada Revenue Agency / Agence du revenu du Canada

Code 1101

SCIENTIFIC RESEARCH AND EXPERIMENTAL DEVELOPMENT (SR&ED) EXPENDITURES CLAIM

Use this form:

- to provide technical information on your SR&ED projects;
- to calculate your SR&ED expenditures; and
- to calculate your qualified SR&ED expenditures for investment tax credits (ITC).

To claim an ITC, use either:

- Schedule T2SCH31, *Investment Tax Credit – Corporations*, or
- Form T2038(IND), *Investment Tax Credit (Individuals)*.

The information requested in this form and documents supporting your expenditures are prescribed information.

Your SR&ED claim must be filed within 12 months of the filing due date of your income tax return.

To help you fill out this form, use the T4088, *Guide to Form T661*, which is available on our Web site: **www.cra.gc.ca/sred**.

Part 1 – General information

010 Name of claimant INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	Enter one of the following: 89242 2817 RC0001 Business Number (BN) Social Insurance Number (SIN)
Tax year From: 2011-01-01 (Year Month Day) To: 2011-12-31 (Year Month Day)	
050 Total number of projects you are claiming this tax year: 2	

100 Contact person for the financial information LAURIE ANN COOLEDGE	**105** Telephone number/extension (705) 431-4321	**110** Fax number
115 Contact person for the technical information LAURIE ANN COOLEDGE	**120** Telephone number/extension (705) 431-4321	**125** Fax number

151 If this claim is filed for a partnership, was Form T5013 filed? . . . . . 1 ☐ Yes 2 ☐ No

If you answered **no** to line 151, complete lines 153, 156 and 157.

153 Name of the partners	**156** %	**157** BN or SIN
1		
2		
3		
4		
5		

Part 2 - Project information

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A - Project identification

200 Project title (and identification code if applicable)

See schedule

Part 3 – Calculation of SR&ED expenditures

What did you spend on your SR&ED projects?

Section A – Select the method to calculate the SR&ED expenditures

I elect (choose) to use the following method to calculate my SR&ED expenditures and related investment tax credits (ITC) for this tax year.
I understand that my election is irrevocable (cannot be changed) for this tax year.

160 [X] I elect to use the proxy method
(Enter "0" on line 360. Complete Part 5 and you do not need to track any expenditure incurred for overhead)

162 [ ] I choose to use the traditional method
(Enter "0" on line 355. Complete line 360, and track any expenditure incurred for overhead)

Section B – Calculation of allowable SR&ED expenditures (to the nearest dollar)

• SR&ED portion of salary or wages of employees directly engaged in the SR&ED:			
a) Employees other than specified employees for work performed in Canada	300	+	40,892
b) Specified employees for work performed in Canada	305	+	
Subtotal (add lines 300 and 305)	306	=	40,892
c) Employees other than specified employees for work performed outside Canada (subject to limitations – see guide)	307	+	
d) Specified employees for work performed outside Canada (subject to limitations – see guide)	309	+	
• Salary or wages identified on line 315 in prior years that were paid in this tax year	310	+	
• Salary or wages incurred in the year but not paid within 180 days of the tax year end 315			
• Cost of materials consumed in performing SR&ED	320	+	
• Cost of materials transformed in performing SR&ED	325	+	
• Contract expenditures for SR&ED performed on your behalf:			
a) Arm's length contracts	340	+	291,464
b) Non-arm's length contracts	345	+	
• Lease costs of equipment used:			
a) All or substantially all (90% of the time or more) for SR&ED	350	+	
b) Primarily (more than 50% of the time but less than 90%) for SR&ED. (Enter 50% of lease costs if you use the proxy method or enter "0" if you use the traditional method)	355	+	
• Overhead and other expenditures (enter "0" if you use the proxy method)	360	+	
• Third-party payments (complete Form T1263*)	370	+	
Total current SR&ED expenditures (add lines 306 to 370; do not add line 315) (Corporations need to adjust line 118 of schedule T2SCH1)	380	=	332,356
• **Capital Expenditures** (see guide for what qualifies for SR&ED) (Do not include these capital expenditures on schedule T2SCH8)	390	+	
Total allowable SR&ED expenditures (add lines 380 and 390)	400	=	332,356

Section C – Calculation of pool of deductible SR&ED expenditures (to the nearest dollar)

Amount from line 400	420		332,356
Deduct			
• provincial government assistance for expenditures included on line 400	429	–	14,956
• other government assistance for expenditures included on line 400	431	–	
• non-government assistance for expenditures included on line 400	432	–	
• SR&ED ITCs applied and/or refunded in the prior year (see guide)	435	–	75,903
• sale of SR&ED capital assets and other deductions	440	–	
Subtotal (line 420 minus lines 429 to 440)	442	=	241,497
Add			
• repayments of government and non-government assistance that previously reduced the SR&ED expenditure pool	445	+	
• prior year's pool balance of deductible SR&ED expenditures (from line 470 of prior year T661)	450	+	
• SR&ED expenditure pool transfer from amalgamation or wind-up	452	+	
• amount of SR&ED ITC recaptured in the prior year	453	+	
Amount available for deduction (add lines 442 to 453) (enter positive amount only, include negative amount in income)	455	=	241,497
• Deduction claimed in the year (Corporations should enter this amount on line 411 of schedule T2SCH1)	460	–	241,497
Pool balance of deductible SR&ED expenditures to be carried forward to future years (line 455 minus 460)	470	=	

* Form T1263, *Third-Party Payments for Scientific Research and Experimental Development (SR&ED)*

Part 4 – Calculation of qualified SR&ED expenditures for investment tax credit (ITC) purposes

The resulting amount is used to calculate your refundable and/or non refundable ITC.

Enter the breakdown between current and capital expenditures (to the nearest dollar)

		Current Expenditures		Capital Expenditures
Total expenditures for SR&ED (from line 380 and 390)	492	332,356	496	
Add				
• payment of prior years' unpaid amounts (other than salary or wages)	500 +			
• prescribed proxy amount (complete Part 5) (Enter "0" if you use the traditional method)	502 +	26,013		
• expenditures on shared-use equipment (see guide)			504 +	
• qualified expenditures transferred to you (complete Form T1146**)	508 +		510 +	
Subtotal (add lines 492 to 508, and add lines 496 to 510)	511 =	358,369	512 =	
Deduct				
• provincial government assistance	513 –	16,127	514 –	
• other government assistance	515 –		516 –	
• non-government assistance and contract payments	517 –		518 –	
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	520 –			
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	528 –			
• prescribed expenditures not allowed by regulations (see guide)	530 –		532 –	
• other deductions (see guide)	533 –		535 –	
• non-arm's length transactions				
– assistance allocated to you (complete Form T1145*)	538 –		540 –	
– expenditures for non-arm's length SR&ED contracts (from line 345)	541 –			
– adjustments to purchases (limited to costs) of goods and services from non-arm's length suppliers (see guide)	542 –		543 –	
– qualified expenditures you transferred (complete Form T1146**)	544 –		546 –	
Subtotal (line 511 minus lines 513 to 544 and line 512 minus lines 514 to 546)	557 =	342,242	558 =	
Qualified SR&ED expenditures (add lines 557 and 558)			559 =	342,242
Add				
• repayments of assistance and contract payments made in the year			560 +	
Total qualified SR&ED expenditures for ITC purposes (add lines 559 and 560)			570 =	342,242

* Form T1145, *Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

Part 5 – Calculation of prescribed proxy amount (PPA)

A notional amount representing your overhead and other expenditures.

This part calculates the PPA to enter on line 502 in Part 4. Do not complete this part if you have chosen to use the traditional method in Part 3 (line 162). You can only claim a PPA if you elected to use the proxy method for the year in Part 3 (line 160).

Special rules apply for specified employees. Calculate your salary base in Section A and the PPA in section B.

Section A – Salary base

Salary or wages of employees other than specified employees (from line 300 and 307)	810	+	40,892
Deduct			
Bonuses, remuneration based on profits, and taxable benefits that were included on line 810	812	–	872
Subtotal (line 810 minus 812)	814	=	40,020

Salary or wages of specified employees

850 Column 1	852 Column 2	854 Column 3	856 Column 4	858 Column 5	860 Column 6
Name of Specified Employee	Total salary or wages for the year (SR&ED and non-SR&ED) excluding bonuses, remuneration based on profits, and taxable benefits (to the nearest dollar)	% of time spent on SR&ED (maximum 75%)	Amount in column 2 multiplied by percentage in column 3	2,5 x A x B/365 A = Year's maximum pensionable earnings B = Number of days employed in tax year	Amount in column 4 or 5, whichever amount is less

(Enter total of column 6 on line 816) — 816 +

Salary base (total of lines 814 and 816) — 818 = 40,020

Section B – Prescribed proxy amount (PPA)

Enter 65% of the salary base (line 818 x 65%) — 820 = 26,013

Enter the amount from line 820 on line 502 in Part 4 unless the overall cap on PPA applies to you.

(See the guide for explanation and example of the overall cap on PPA)

Part 6 – Project costs

Information requested in this part must be provided for **all** SR&ED projects claimed in the year.
Expenditures should be recorded and allocated on a project basis.

750 Project title or identification code	752 Salary or wages in the tax year (Total of lines 306 to 309)	754 Cost of materials in the tax year (Total of lines 320 and 325)	756 Contract expenditures for SR&ED performed on your behalf in the tax year (Total of lines 340 and 345)
1. Advanced Structural Engineering Techniques for Undergrour	27,651		237,138
2. Advanced Power and Communication Techniques	13,241		54,326
Total	40,892		291,464

Part 7 – Additional information

Expenditures for SR&ED performed by you in Canada (line 400 minus lines 307, 309, 340, 345, and 370) 605 40,892

From the total you entered on line 605, estimate the percentage of distribution of the sources of funds for SR&ED performed within your organization.

		Canadian (%)		Foreign (%)
Internal	600	100.000		
Parent companies, subsidiaries, and affiliated companies	602		604	
Federal grants (do not include funds or tax credits from SR&ED tax incentives)	606			
Federal contracts	608			
Provincial funding	610			
SR&ED contract work performed for other companies on their behalf	612		614	
Other funding (e.g., universities, foreign governments)	616		618	

Enter the number of SR&ED personnel in full-time equivalents (FTE):

Scientists and engineers	632	
Technologists and technicians	634	2
Managers and administrators	636	
Other technical supporting staff	638	

Part 8 – Claim checklist

To ensure your claim is complete, make sure you have:

1. used the current version of this form X
2. entered the method you have chosen for reporting your SR&ED expenditures in Section A of Part 3 X
3. completed Part 2 for each project X
4. filed a completed Schedule T2SCH31 or Form T2038(IND) to claim ITCs on your qualified SR&ED expenditures X
5. filed a completed Form T1145*, T1146**, T1174*** and/or T1263**** including any required attachments, if applicable X

To expedite the processing of your claim, make sure you have:

1. completed Form T2, *Corporation Income Tax Return* or Form T1, *Income Tax and Benefit Return* X
2. filed the appropriate provincial and/or territorial tax credit forms, if applicable X
3. retained documents to support the SR&ED expenditures you claimed X
4. checked boxes 231 and 232 on page 2 of your T2 return to indicate attachment of Form T661 and Schedule T2SCH31 X

* Form T1145, *Agreement ta Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement ta Transfer Qualified Expenditures Incurred In Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

*** Form T1174, *Agreement Between Associated Corporations to Allocate Salary or Wages of Specified Employees for Scientific Research and Experimental Development (SR&ED)*

**** Form T1263, *Third-Party Payments for Scientific Research and Experimental Development (SR&ED)*

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Part 9 – Certification

I certify that I have examined the information provided on this form and on the attachments and it is true, correct, and complete.

165 LAURIE ANN COOLEDGE
Name of authorized signing officer of the corporation, or individual

Signature

170 2012-06-28
Date

175 Grant Thornton LLP
Name of person/firm who completed this form

Part 2 - Project information (continued)

Project number 1

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

Advanced Structural Engineering Techniques for Underground P

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2010-01 (Year Month)	2011-11 (Year Month)	2.01.03 Municipal and structural engineering

Project claim history

208 1 [X] Continuation of a previously claimed project **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

The work was carried out (check any that apply)

223 1 [ ] In a laboratory

224 1 [ ] In a dedicated research facility

226 1 [X] In a commercial plant or facility

228 1 [X] Others, specify **229** Town of Innisfill

Purpose of the work

230 1 [X] To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 [ ] For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 [ ]	**236** 1 [X]
The improvement of existing	**237** 1 [ ]	**238** 1 [X]

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

1. The technological objective of this project was the development of new
2. techniques for design of high strength structures for underground power
3. distribution systems.
4.
5. Innisfil Hydro has developed highly specialized techniques involving deep
6. excavation to by-pass storms and water mains; detours construction under
7. buried/abandoned culvers and around undocumented pipe systems; relocation of
8. utility trenches due to unmapped field obstructions; construction of fiber
9. optic duct systems; and substation trench structures for electrical power
10. systems. This project was driven by the high accuracy design goals for
11. underground power distribution systems to achieve high reliability structural
12. integrity and durability within the dimensioning and field mapping constraints
13. of existing non-uniform civil, and other utilities (gas, communication,
14. sewers) structures. Conventional design methods for the underground power
15. distribution systems have failed to achieve the high structural integrity due
16. to the extensive interactions with already constructed underground civil, gas,
17. and communication infrastructures that results in weakened joint structures,
18. uneven particle distribution, and soil porosity and inconsistency. The new
19. techniques had not been attempted previously due to the challenges with the
20. design of core civil structures (ducts, trenches) that needed to be developed
21. for strength, high consistency, and durability within the overall development

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

area of Innisfil Hydro's underground power distribution system structure.

We gained knowledge on how to develop high strength high integrity underground trenches, detour constructions, ducts structures and underground power distribution structural system components (vaults, equipment bases, culverts and pipes) with high consistency for underground power distribution systems and applications including:

- We designed the deep excavation techniques to by-pass the storm and water mains and detour methods for trench construction under buried/abandoned culvers and undocumented pipe systems overcoming constraints of uneven particle distribution and limited soil consistency. For instances of encountering the unmapped private civil septic structures (tile beds, septic systems) we developed new trench methodologies. We designed new trench isolation techniques for trench development within the power substation perimeter from the extensive underground fault grounding grids and connecting metal rod systems. The new design techniques allowed achieving our design goals for high strength structures for high reliability underground power distribution systems developed by Innisfil Hydro.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

There was no available knowledge of the efficient high accuracy methodology for new structural designs overcoming the variances in the existing power distribution underground structures. The existing, new and upgraded ground structures were not existent on any municipal mapping systems resulting in highly variable ground and structural conditions. The undocumented underground civil structure systems caused the extensive detours and relocations of utility trenches and required development of the new trench systems.

- The first challenge was encountered with the unmapped storm and water mains systems as the initial attempt to detour the underground power distribution system failed due to the existing storm and water ground structures and proximity of the underground street light pass-thru formations that resulted in dimensional changes to the channel wall structures. Development work continued to improve the detour technique for running trenches under buried/abandoned culvers and undocumented pipe systems. We were uncertain if testing the ground for voids and soil components porosity could indicate any structural non-uniformity affecting the required trench development. There were significant concerns with the existing storm and water mains system material characteristics and strength due to the aged and weakened joint structures and water mains components. The constraints of the limited soil consistency and uneven particle distribution had to be overcome during the iterative experimentation phase.

The team intended to develop a new trench development methodology to address unexpected and unmapped civil septic system structures. We were uncertain if the variability of the existing tile bed structures and the septic systems walls with diminished material strength characteristics across the structure would cause the possibility of the groundwater leakage impacting the reliability of underground power distribution system development.

We intended to design a new method for connecting the substation power supply with the outside perimeter security systems and power components installations. The existing substation structural engineering techniques allowed for an uncontrolled layout of wiring connections from the surrounding protection fence to the power supply at the centre of a substation. During the preliminary trench development, the presence of an extensive undersurface grounding grid system designed for the high voltage fault clearing complicated the trench construction and required developing the isolation techniques between the new trenches and grounding grid system. There was no existing

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? *(Maximum 50 lines)*

38. method for the proposed structural trench design work within the power
39. substation perimeter.
40.
41.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) *(Maximum 100 lines)*

1. In fiscal 2011, we began the development of the first attempt at the new
2. detour technique for the underground power distribution system. The design
3. work began when the team encountered existing underground water mains and
4. storm structures. The complicated factor was the close proximity of the
5. street light pass-thru formations. There were significant concerns with
6. whether these aged civil infrastructure constraints could impact the
7. development of the new detour techniques. The team had to ensure that the
8. existing civil infrastructures could be retained and secured within the
9. limitations of the reduced structural integrity and diminished material
10. strength characteristics. The team performed the in-situ engineering analysis
11. including the soil compaction testing, crushed particle analysis and washed
12. sieve analysis. There were concerns with whether the development of the new
13. deep excavation and trench detour techniques could proceed without the
14. constraints of the limited soil consistency and uneven particle distribution.
15. The initial prototype of a trench detour was investigated for inconsistencies
16. in the trench uniformity and structural errors. The new technique was
17. developed to ensure the high accuracy of the excavation structure and dust
18. abatement process to ensure the high consistency with civil infrastructure
19. modifications required then for the underground power distribution system
20. development.
21. We investigated the instances when the development of the underground power
22. system was impacted by unexpected and unmapped civil septic structures. There
23. were concerns that the encountered tile bed arrangements could cause the
24. potential groundwater leak into our trench development structures. The
25. initial material structure tests indicated that the extensive tile bed
26. dimensions were impacting the strength of its structure characteristics and
27. own ability to remain intact. Several iterations of tests began on the
28. performance of the septic system structure to address the perceived unstable
29. septic tile bed arrangements before the trench development could continue
30. further.
31. We began the development of new trenching techniques for substation electrical
32. systems connecting the outside perimeter security systems and the centrally
33. located substation power supply. The team analyzed servicing requirements of
34. the new proposed development to understand the most reliable connection layout
35. plans and new implementation approaches. The study was performed in-situ and
36. the analysis of the existing wiring connection layout for the connections
37. determined that the trench alternative with the piping conduits could be a
38. viable option for the new infrastructure design. There were significant
39. concerns that efficiency of clearing thunder strikes and overcurrent faults
40. through the exposed copper grounding lead connections with the underground
41. expansive grid system could be impacted by any additional trench development.
42. The initial constraint we encountered with the trench development activities
43. was an underground complex network of vertical grounding metal rods and plates
44. located under the gravel surface in different horizontal planes. Their
45. discovered layouts did not agree with any anticipated underground grounding
46. grid layouts, location depths and rod and plate connections. There were also
47. concerns with the proximity of the trench development to the grounding grid;
48. ultimately the isolation issue had to be addressed. The location variances of
49. the underground grounding grid caused the team to deviate from the preliminary
50. design and earlier developed trench development layout, and imposed additional
51. space requirement of the increased distance between the high voltage clearing

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

grid connections and the low voltage electrical installation. The complete redesign was necessary as the different grounding connection pathways were not contained in one horizontal plane creating the structural underground obstructions for our trench development. Through experimentation we developed a new multi-plane trench development design approach to accommodate the unexpected obstacles of multiple rod locations and multi-level ground grid positions in order to account for the required isolation ground distance clearance.

Through fiscal 2011, we built several prototype designs and developed a variety of deep excavation, duct remediation, detour, relocation of utility trenches, construction of fiber optic duct systems and substation trenching techniques. By mid November, we met the design goals for the underground power distribution systems to achieve high reliability structural integrity and durability within the dimensioning and field mapping constraints of existing non-uniform civil and other utilities structures, and not uniform underground grounding grid space limitations.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 [X] Employee directly involved in the project

254 Name: Wade Morris

255 1 [ ] Other employee of the company

256 Name:

257 1 [ ] External consultant

258 Name:

259 Firm:

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	**261** Qualifications/experience and position title
1	Wade Morris	VP of Engineering&Operations; C.Tech., C.I.M; 20+ years power industry experience
2	Christopher Latouf	Certified Electrical Technician; 10+ years power industry experience
3	Matthew Cousins	Certified Electrical Technician; 10+ years power industry experience

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [X] Yes 2 [ ] No

If you answered **yes** to line 267, complete lines 268 and 269.

268	Names of individuals or companies	269 BN
1	Hydro Vacuum Systems	80687 5290 RC0001
2	Sturdy Power Lines Ltd.	11429 0935 RC0001
3	Robert B. Somerville Co. Limited	83807 4359 RC0001
4	Terraprobe Inc.	10517 9949 RC0001
5	Cable Master Inc.	13731 8721 RC0001
6	Engineering Technical Support Services	81432 6146 RC0001
7	Aecon Utilities	88720 1887 RC0001
8	HGR Graham Partners LLP	12225 4311 RC0001
9	H.F. Smith Lumber Inc.	81583 2340 RC0001
10	CDW Canada	87814 6000 RC0001
11	Ideal Supply Company Ltd	10244 8511 RC0001
12	Faris Excavating Ltd	86470 7955 RC0001
13	Cornerstone	13226 2346 RC0001
14		

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	1	[X]	Project planning documents	276 1 [X]	Progress reports, minutes of project meetings
271	1	[X]	Records of resources allocated to the project, time sheets	277 1 [ ]	Test protocols, test data, analysis of test results, conclusions
272	1	[ ]	Design of experiments	278 1 [ ]	Photographs and videos
273	1	[X]	Project records, laboratory notebooks	279 1 [ ]	Samples, prototypes, scrap or other artefacts
274	1	[ ]	Design, system architecture and source code	280 1 [X]	Contracts
275	1	[ ]	Records of trial runs	281 1 [X]	Others, specify 282 Invoices, Emails

Part 2 - Project information (continued)

Project number **2**

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

Advanced Power and Communication Techniques

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2011-03 (Year Month)	2011-12 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [ ] Continuation of a previously claimed project **210** 1 [X] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

The work was carried out (check any that apply)

223 1 [ ] In a laboratory **226** 1 [X] In a commercial plant or facility

224 1 [ ] In a dedicated research facility **228** 1 [X] Others, specify **229** Town of Innisfill

Purpose of the work

230 1 [X] To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 [ ] For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 [ ]	**236** 1 [ ]
The improvement of existing	**237** 1 [X]	**238** 1 [X]

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

1. The technological objective of this project was the development of advanced
2. power engineering techniques for the design of power engineering component
3. networks (transformer tap changers, automatic reclosers, Scada mate switches,)
4. to achieve the increased interoperability within power distribution system and
5. high accuracy operational reliability.
6.
7. Innisfil Hydro has developed the specialized power engineering techniques for
8. high voltage power distribution industrial components. This project was
9. driven by the design goals for modern power distribution structures including
10. advanced methods and mechanisms for improving the design of highly reliable
11. engineering component networks and communication means for the high accuracy
12. voltage control, voltage regulation, short circuit fault clearing, recovery
13. management system, network auto-sectionalizing and switching control.
14. Conventional techniques for the development of the power engineering
15. techniques for power distribution components have failed to achieve highly
16. reliable fault and outage clearing capability. The manual voltage regulation
17. techniques were still required for the transformer bank and load shifting
18. operations. The automatic remotely controlled power distribution component
19. interoperability and control had not been attempted previously due to
20. challenges with the unstable communication network and reactive management of
21. the power grid components.

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

We gained knowledge on how to develop the power engineering techniques to ensure the high accuracy interoperability and control capability between the remote locations of the power engineering components (transformers, automatic reclosers, Scada mate switches) and centrally located control system.

- We designed new voltage regulation techniques for the transformer tap changer development to ensure reliable remotely controlled capability for transformer bank operations, while at the same time achieving our design goals for low risk of unbalanced bus voltage conditions. We developed an understanding of intermittent connection interruptions in our communication network resulting in the low quality signals and unstable control of our power distribution components.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

There was no available knowledge of the behaviour and characteristics of the intelligent power distribution component networks operating in the field areas with observed high level of signal interference while communicating with the remote recloser, switch or transformer bank substation locations. The existing techniques had significant limitations the needed to be overcome, including:

- The team intended to develop new techniques for the design of transformer bank operation for high precision remotely controlled tap changer adjustments. We were uncertain if the new remotely controlled tap changer adjustments operation can be performed reliably to eliminate the risk of unwanted current flowing between the transformer bank secondary winding during unbalanced bus voltage conditions. The initial prototype of the remotely controlled transformer tap changer regulation design failed due to the unreliable method of detecting a tab position in the tab changer configuration. The subsequent challenge we encountered was in development of high reliability communication networks to eliminate the low quality communication signals resulting in the intermittent connection interruptions. There were concerns that the interference with adjacent networks frequency bands, ground surface obstructions and inconsistencies in the land surface levels would result in the communication failures and prevent achieving the reliable operability of the crucial power distribution components in the field. During initial testing of the communication network the remote recloser and switch operation failed due to low signal strength ratio.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

We began the development of the first attempt at a prototype of an intelligent power distribution component network in fiscal 2011. The design work began including the design of control structures for the system of existing automatic reclosers, switches and substations. There were significant concerns with whether the power distribution component networks could achieve high accuracy interoperability and control capability between the remote locations of the power engineering components and centrally located control system.

We began the development of new techniques for the design of transformer bank operation for high precision remotely controlled tap changer adjustments. The analysis led to the design of the on-site monitoring module for sensing tab voltages, recording tap changer positions and signaling the detailed information for the necessary voltage adjustments to the remote control system. The technological challenge was to develop a reliable method to detect a tab position in the tab changer configuration. The voltage monitoring module prototype utilized a math variable approach to calculate the detected instances of tap changer operations. The developed counting

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

algorithm increased the variable every time the tap went up, and decreased the variable if the tap went down. Testing with this first approach showed that errors in counting accuracy continued and changes were made in an attempt to improve the accuracy. The design changes included the development of the de-bouncing algorithm, which required monitoring of the relay closure times. We observed that the relay closure interval was in the range of 3 seconds. Further testing with adjusting the relay closure time (debounce time) to 1 second did not reveal any improvements. Ultimately, the inaccuracies in detecting tap changer positions resulted in a failure of remote attempts to balance the voltage on the common bus for transformers secondary windings. Through experimentation we learned that the failure could be addressed by developing the new counter-based tab change measuring technique. The verification testing revealed higher accuracy readings and this newly developed approach was accepted as the future standard operating procedure.

We began to build the components of the power distribution component network structure with the modern wireless communication enabled automatic reclosers and Scada mate switches. Initial testing of the prototype network began in an attempt to overcome the unstable intermittent responses of the wireless network components to the control commands while observing significant inconsistencies in the wireless signal coverage. Several iterations of tests began on the performance of communication with the new reclosers and switches at the various remote locations. Testing with initial design showed that unknown errors prevented the reclosers and switches to respond to the CLOSE command and transmit the relevant data. Through experimentation we learned that collected fault logs data was corrupted and changed the default settings on the Scada switches. Initial design changes were made based on the verification of collected data to improve the initial design. At the end of June 2011, further design changes were made to improve the reliability of the wireless communication and overcome low quality wireless signal constraints. The control testing of switch connections and setups commenced in August 2011. The observed improvement in checking percentage of the CLOSED ON SWITCH operation reached 106.8%, and was achieved after tightening the switch communication conduit connections. In September 2011, the team encountered further challenges with radio screens for the new Scada mate switches. The analysis revealed that advanced radio screen changes were required to enable new switches' proper operation with the communication protocol, and ultimately the new revised radio screens were developed. In November 2011, the team prototyped the new control module for Scada mate switches and developed the fault indicator control component to work with a specific type of wireless radio receivers. Design changes were made to improve the communication signal strength ratio observed to be 6dBmW below the acceptable limit.

Through fiscal 2011, we built several prototype designs and developed the specialized power distribution component network and communication techniques for high voltage power distribution industrial components. By the end of December, we met the design goals for modern power distribution structures to achieve the increased interoperability within power distribution system and high accuracy operational reliability, including advanced methods and mechanisms for improving the design of communication networks, high reliability and accuracy of transferred information and recovery management after the fault events.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

3.

4.

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

1.

2.

3.

4.

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 [X] Employee directly involved in the project

254 Name: Wade Morris

255 1 [ ] Other employee of the company

256 Name:

257 1 [ ] External consultant

258 Name:

259 Firm:

List the key individuals directly involved in the project and indicate their qualifications/experience.

260	Names	**261** Qualifications/experience and position title
1	Wade Morris	VP of Engineering&Operations; C.Tech., C.I.M; 20+ years power industry expe
2	Robert Real	Certified Electrical Technician; 10+ years power industry experience
3	Peter Stephens	Certified Electrical Technician; 10+ years power industry experience

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [X] Yes 2 [ ] No

If you answered **yes** to line 267, complete lines 268 and 269.

268	Names of individuals or companies	**269** BN
1	Hydro Vacuum Systems	80687 5290 RC0001
2	Sturdy Power Lines Ltd.	11429 0935 RC0001
3	PC Applications	13669 0856 RC0001
4	Power Systems Utility Services (1993) Inc.	88575 9860 RC0001
5	Faris Excavating Ltd	86470 7955 RC0001
6	R.B. Enterprises	10629 7674 RC0001
7	Wamco Waterorks	10162 6026 RC0001
8	Lafarge North America	10293 0856 RC0001
9		

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270 1 [X] Project planning documents

271 1 [X] Records of resources allocated to the project, time sheets

272 1 [ ] Design of experiments

273 1 [X] Project records, laboratory notebooks

274 1 [ ] Design, system architecture and source code

275 1 [ ] Records of trial runs

276 1 [X] Progress reports, minutes of project meetings

277 1 [X] Test protocols, test data, analysis of test results, conclusions

278 1 [ ] Photographs and videos

279 1 [ ] Samples, prototypes, scrap or other artefacts

280 1 [X] Contracts

281 1 [X] Others, specify **282** Invoices, Emails

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

055 **Do not use this area**

Identification

Business Number (BN) 001 89242 2817 RC0001

Corporation's name
002 INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED

Address of head office
Has this address changed since the last time we were notified? . . . . . 010 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 011 to 018.)
011 2073 COMMERCE PARK DR
012

City	Province, territory, or state
015 INNISFIL	016 ON
Country (other than Canada)	**Postal code/Zip code**
017	018 L9S 4A2

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . . 020 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 021 to 028.)
021 c/o
022 2073 COMMERCE PARK DR
023

City	Province, territory, or state
025 INNISFIL	026 ON
Country (other than Canada)	**Postal code/Zip code**
027	028 L9S 4A2

Location of books and records
Has the location of books and records changed since the last time we were notified? . . . . . 030 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 031 to 038.)
031 2073 COMMERCE PARK DR
032

City	Province,territory, or state
035 INNISFIL	036 ON
Country (other than Canada)	**Postal code/Zip code**
037	038 L9S 4A2

040 Type of corporation at the end of the tax year

1 ☒ Canadian-controlled private corporation (CCPC)
2 ☐ Other private corporation
3 ☐ Public corporation
4 ☐ Corporation controlled by a public corporation
5 ☐ Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 _____ YYYY MM DD

To which tax year does this return apply?

Tax year start	Tax year-end
060 2011-01-01	061 2011-12-31
YYYY MM DD	YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . . 063 1 Yes ☐ 2 No ☒

If **yes**, provide the date control was acquired . . . . . 065 _____ YYYY MM DD

Is the date on line 061 a deemed tax year-end according to:
subparagraph 88(2)(a)(iv)? . . . . . 064 1 Yes ☐ 2 No ☒
subsection 249(3.1)? . . . . . 066 1 Yes ☐ 2 No ☒

Is the corporation a professional corporation that is a member of a partnership? . . . . . 067 1 Yes ☐ 2 No ☒

Is this the first year of filing after:
Incorporation? . . . . . 070 1 Yes ☐ 2 No ☒
Amalgamation? . . . . . 071 1 Yes ☐ 2 No ☒
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . . 072 1 Yes ☐ 2 No ☒
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . . 076 1 Yes ☐ 2 No ☒

Is this the final return up to dissolution? . . . . . 078 1 Yes ☐ 2 No ☒

If an election was made under section 261, state the functional currency used . . . . . 079 _____

Is the corporation a resident of Canada?
080 1 Yes ☒ 2 No ☐ If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081 _____

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . . 082 1 Yes ☐ 2 No ☒
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 ☐ Exempt under paragraph 149(1)(e) or (l)
2 ☐ Exempt under paragraph 149(1)(j)
3 ☐ Exempt under paragraph 149(1)(t)
4 ☐ Exempt under other paragraphs of section 149

Do not use this area

095 _____ 096 _____

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213	X	13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	1 Yes	2 No X
Is the corporation inactive?	280	1 Yes	2 No X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution US

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricity Distributor	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes	2 No X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes	2 No X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	1 Yes	2 No
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible	294		YYYY MM DD
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295	1 Yes	2 No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		1,591,372	A
Deduct: Charitable donations from Schedule 2	311	290		
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal		290 ▶	290	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			1,591,082	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		1,591,082	
Income exempt under paragraph 149(1)(t)	370			
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			1,591,082	Z

* This amount is equal to 3.2 times the Part VI.1 tax payable at line 724 on page 8. Use 3.5 for tax years ending after 2011.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . . 400 1,591,372 A

Taxable income from line 360 on page 3, **minus** 100/28* 3.37312 of the amount on line 632** on page 7, **minus** 1/(0.38 - X***) 3.77358 times the amount on line 636**** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . . 405 1,591,082 B

Business limit (see notes 1 and 2 below) . . . . . 410 500,000 C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x 415 ***** 40,047 / 11,250 D = ... 1,779,867 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . 425 F

Small business deduction

Amount A, B, C, or F, whichever is the least x 17 % = ... 430 G

Enter amount G on line 1 on page 7.

* 10/3 for tax years ending before November 1, 2011. The result of the multiplication by line 632 has to be pro-rated based on the number of days in the tax year that are in each period: before November 1, 2011, and after October 31, 2011.

** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

*** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

**** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3*			1,591,082 A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27			B
Amount QQ from Part 13 of Schedule 27			C
Personal service business income**	432		D
Amount used to calculate the credit union deduction from Schedule 17			E
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			F
Aggregate investment income from line 440 on page 6***			G
Total of amounts B to G		▶	H
Amount A **minus** amount H (if negative, enter "0")			1,591,082 I

Amount I	1,591,082	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year		x	9 %	=	J
Amount I	1,591,082	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year		x	10 %	=	K
Amount I	1,591,082	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	365 / 365	x	11.5 %	=	182,974 L
Amount I	1,591,082	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year		x	13 %	=	M

General tax reduction for Canadian-controlled private corporations – Total of amounts J to M . . . . . 182,974 N
Enter amount N on line 638 on page 7.

* For tax years ending after October 31, 2011, line 360 or amount Z, whichever applies.

** For tax years beginning after October 31, 2011.

*** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)			O
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27			P
Amount QQ from Part 13 of Schedule 27			Q
Personal service business income*	434		R
Amount used to calculate the credit union deduction from Schedule 17			S
Total of amounts P to S		▶	T
Amount O **minus** amount T (if negative, enter "0")			U

Amount U		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year		x	9 %	=	V
Amount U		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year		x	10 %	=	W
Amount U		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	365 / 365	x	11.5 %	=	X
Amount U		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year		x	13 %	=	Y

General tax reduction – Total of amounts V to Y . . . . . Z
Enter amount Z on line 639 on page 7.

* For tax years beginning after October 31, 2011.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 ..... 440 _____ x 26 2 / 3 % = ... _____ A

Foreign non-business income tax credit from line 632 on page 7 ..... _____

Deduct:

Foreign investment income from Schedule 7 ..... 445 _____ x 9 1 / 3 % = _____
(if negative, enter "0") _____ ▶ _____ B

Amount A **minus** amount B (if negative, enter "0") ..... _____ C

Taxable income from line 360 on page 3 1,591,082

Deduct:

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least ..... _____

Foreign non-business income tax credit from line 632 on page 7 ... _____ x 25/9* 25 / 9 = _____

Foreign business income tax credit from line 636 on page 7 ..... _____ x 1(0.38 - X**) 3.77358 = _____

_____ ▶ _____

1,591,082

x 26 2 / 3 % = 424,289 D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) ..... 194,081 E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least ..... 450 _____ F

* 100/35 for tax years beginning after October 31, 2011.

** General rate reduction percentage for the tax year. It has to be pro-rated.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year ..... 460 _____

Deduct: Dividend refund for the previous tax year ..... 465 _____

_____ ▶ _____ G

Add the total of:

Refundable portion of Part I tax from line 450 above ..... _____

Total Part IV tax payable from Schedule 3 ..... _____

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation ..... 480 _____

_____ ▶ _____ H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H ..... 485 _____

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 ..... 625,000 x 1 / 3 208,333 I

Refundable dividend tax on hand at the end of the tax year from line 485 above ..... _____ J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 on page 8) .....

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 % 550 604,611 A

Recapture of investment tax credit from Schedule 31 . . . . . 602 B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6 i

Taxable income from line 360 on page 3 1,591,082

Deduct:

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . .

Net amount . . . . . 1,591,082 ▶ 1,591,082 ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . . 604 C

Subtotal (**add** lines A to C) 604,611 D

Deduct:

Small business deduction from line 430 on page 4 1

Federal tax abatement 608 159,108

Manufacturing and processing profits deduction from Schedule 27 616

Investment corporation deduction 620

Taxed capital gains 624

Additional deduction – credit unions from Schedule 17 628

Federal foreign non-business income tax credit from Schedule 21 632

Federal foreign business income tax credit from Schedule 21 636

General tax reduction for CCPCs from amount N on page 5 . . . . . 638 182,974

General tax reduction from amount Z on page 5 639

Federal logging tax credit from Schedule 21 640

Federal qualifying environmental trust tax credit 648

Investment tax credit from Schedule 31 . . . . . 652 68,448

Subtotal 410,530 ▶ 410,530 E

Part I tax payable – Line D **minus** line E . . . . . 194,081 F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	194,081	
Part II surtax payable from Schedule 46	708		
Part III.1 tax payable from Schedule 55	710		
Part IV tax payable from Schedule 3	712		
Part IV.1 tax payable from Schedule 43	716		
Part VI tax payable from Schedule 38	720		
Part VI.1 tax payable from Schedule 43	724		
Part XIII.1 tax payable from Schedule 92	727		
Part XIV tax payable from Schedule 20	728		
Total federal tax			194,081

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	108,836	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765		
		108,836 ▶	108,836
Total tax payable	770		302,917 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from page 6	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	856,220	
Total credits	890	856,220 ▶	856,220 B

Refund code 894 1 Overpayment 553,303

Balance (line A **minus** line B) -553,303

If the result is negative, you have an **overpayment.**
If the result is positive, you have a **balance unpaid.**
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, 950 COOLEDGE (Last name in block letters) 951 LAURIE ANN (First name in block letters) 954 Treasurer (Position, office, or rank),
am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2012-06-28 (Date (yyyy/mm/dd)) Signature of the authorized signing officer of the corporation 956 (705) 431-4321 (Telephone number)

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes ☒ 2 No ☐

958 Name in block letters 959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Privacy Act, Personal Information Bank number CRA PPU 047

Schedule of Instalment Remittances

Name of corporation contact
Telephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Installments made during 2010 taxation year	856,220
	payment in 2011	
	payment made AYE	

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 856,220 **A**

Total instalments credited to the taxation year per T9 856,220 **B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	7,040,179	8,041,237
	Total tangible capital assets	2008	+	52,269,147	50,156,157
	Total accumulated amortization of tangible capital assets	2009	–	27,938,672	27,555,402
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	4,325,669	4,624,599
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	35,696,323	35,266,591
Liabilities					
	Total current liabilities	3139	+	11,181,847	12,742,982
	Total long-term liabilities	3450	+	8,358,525	6,853,518
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	19,540,372	19,596,500
Shareholder equity					
	Total shareholder equity (mandatory field)	3620	+	16,155,951	15,670,091
	Total liabilities and shareholder equity	3640	=	35,696,323	35,266,591
Retained earnings					
	Retained earnings/deficit – end (mandatory field)	3849	=	4,747,887	4,262,027

* Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

Income statement information

Description	GIFI

Operating name	0001	
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
Income statement information					
	Total sales of goods and services	8089	+	29,203,939	27,946,138
	Cost of sales	8518	–	21,570,056	20,393,170
	Gross profit/loss	8519	=	7,633,883	7,552,968
	Cost of sales	8518	+	21,570,056	20,393,170
	Total operating expenses	9367	+	6,773,895	6,443,859
	Total expenses (mandatory field)	9368	=	28,343,951	26,837,029
	Total revenue (mandatory field)	8299	+	29,748,211	28,384,441
	Total expenses (mandatory field)	9368	–	28,343,951	26,837,029
	Net non-farming income	9369	=	1,404,260	1,547,412
Farming income statement information					
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	1,404,260	1,547,412
	Total other comprehensive income	9998	=		
Extraordinary items and income (linked to Schedule 140)					
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	437,400	825,000
	Future (deferred) income tax provision	9995	–	-144,000	-198,000
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	1,110,860	920,412

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Revenue

SCHEDULE 125

Form identifier 8299

Account	Description	GIFI		Current year	Prior year
	* Trade sales of goods and services	8000	+	29,203,939	27,946,138
	Total sales of goods and services	8089	=	29,203,939	27,946,138
Investment revenue					
	Interest from other Canadian sources	8094		490,943	36,839
	Investment revenue		+	490,943	36,839
Other revenue					
	* Other revenue	8230		53,329	401,464
	Other revenue		+	53,329	401,464
	Total revenue	8299	=	29,748,211	28,384,441

* Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Cost of Sales

SCHEDULE 125

Form identifier 8518

Account	Description	GIFI	Current year	Prior year
	* Purchases/cost of materials	8320 +	21,570,056	20,393,170
	Cost of sales	8518 =	21,570,056	20,393,170

* Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Operating Expenses

SCHEDULE 125

Form identifier 9367

Account	Description	GIFI		Current year	Prior year
Advertising and promotion					
	Meals and entertainment	8523		12,082	10,053
	Advertising and promotion		+	12,082	10,053
	* Amortization of tangible assets	8670	+	1,894,236	1,965,295
Interest and bank charges					
	Interest on long-term debt	8714		672,042	546,512
	Interest and bank charges		+	672,042	546,512
Office expenses					
	* Office expenses	8810		1,806,007	1,702,947
	Office expenses		+	1,806,007	1,702,947
Other expenses					
	* Other expenses	9270		1,464,232	1,296,309
	Selling expenses	9273		925,296	922,743
	Other expenses		+	2,389,528	2,219,052
	Total operating expenses	9367	=	6,773,895	6,443,859

* Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 141

NOTES CHECKLIST

Name of corporation	Business Number	Tax year-end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation?	095	1 Yes	X	2 No	
Is the accountant connected* with the corporation?	097	1 Yes		2 No	X

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note: If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report	1	X
Completed a review engagement report	2	
Conducted a compilation engagement	3	

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation?	099	1 Yes		2 No	X

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client)	1	
Prepared the tax return and the financial information contained therein (financial statements have not been prepared)	2	

Were notes to the financial statements prepared?	101	1 Yes	X	2 No	

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes?	104	1 Yes		2 No	X
Is re-evaluation of asset information mentioned in the notes?	105	1 Yes		2 No	X
Is contingent liability information mentioned in the notes?	106	1 Yes	X	2 No	
Is information regarding commitments mentioned in the notes?	107	1 Yes	X	2 No	

Does the corporation have investments in joint venture(s) or partnership(s)?	108	1 Yes		2 No	X

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . 200 1 Yes ☐ 2 No ☒

If **yes**, enter the amount recognized:		**In net income** Increase (decrease)		**In OCI** Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year? . . . . . 250 1 Yes ☐ 2 No ☒

Did the corporation apply hedge accounting during the tax year? . . . . . 255 1 Yes ☐ 2 No ☒

Did the corporation discontinue hedge accounting during the tax year? . . . . . 260 1 Yes ☐ 2 No ☒

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . 265 1 Yes ☐ 2 No ☒

If **yes**, you have to maintain a separate reconciliation.

T2 BAR CODE RETURN

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BN: 89242 2817 RC 0001

Tax Year Start: 2011-01-01

Tax Year End: 2011-12-31

Innisfil Hydro Distribution Systems Limited

Notes to the Financial Statements

December 31, 2011

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, bank indebtedness, short term investments, (maturity of 3 months or less), and bank balances.

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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 revenue for the period based on customer's usage since the last meter-reading date to the end of the period. Unbilled revenue is recognized for customer usage not billed at December 31, 2011.

Other revenue, including miscellaneous service revenues and miscellaneous non-operating income are recognized as services are rendered. Other revenue, relating to late payment charges, pole rentals and interest revenue are recognized as they are earned and measurable. Scientific research and development tax credits (SRED) are recognized in other revenue when they have been applied for and are measurable.

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. Costs include all acquisition costs incurred in bringing inventory to its present location and condition. Net realizable value is the estimated selling price in the ordinary cost of business less any applicable selling expenses. The Company classifies rebates received from vendors as a reduction to the cost of inventory. Amount of inventory expensed during the year was $11,747 (2010 - $16,408).

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Innisfil Hydro Distribution Systems Limited

Notes to the Financial Statements

December 31, 2011

2. Summary of significant accounting policies (Continued)

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, 2011 are disclosed in Note 8.

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.

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Amortization

Property and equipment are recorded at cost less accumulated amortization. Property and equipment that is under construction in process (CIP) is not amortized until it is ready for use.

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

Land rights	50	years
Building and fixtures	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 or intangible assets are sold, the cost of the asset and the related accumulated amortization is removed from the accounts, when identifiable 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 when it is identifiable.

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Innisfil Hydro Distribution Systems Limited

Notes to the Financial Statements

December 31, 2011

2. Summary of significant accounting policies (Continued)

Property and equipment 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 property and equipment 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 property and equipment.

Some of the Company's assets may have asset retirement obligations. As the Company expects to use the majority of its property and equipment 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.

Intangible assets

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Intangible assets represent computer applications software and land rights. These assets are carried at cost net of accumulated amortization.

Corporate income and capital taxes

The Company uses the liability method of tax allocation for accounting for income. Under the liability method of tax allocation, temporary differences arising from the difference between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax liabilities or assets. Future income tax liabilities or assets are measured using the substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse. A valuation allowance is recognized to the extent the recoverability of future income tax assets are not considered more likely than not.

Under the Electricity Act, 1998, the Company is required to make payments in lieu of corporate taxes to the 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.

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial

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statements and the reported amounts of revenues and expenses during the reporting period. These estimates and assumptions are based on management's historical experience, best knowledge of current events and actions that the Company may undertake in the future. Significant accounting estimates include allowance for doubtful accounts, unbilled revenue, inventory obsolescence, regulatory assets and liabilities and estimated useful lives of property and equipment. Actual results could differ from those estimates.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2011

2. Summary of significant accounting policies (Continued)

Financial instruments, hedges, and comprehensive income

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

" Cash and deposits at the Company have been classified as "held for trading". GIC investments included and cash and cash equivalents are classified as "held to maturity". They are initially measured at fair value and the gains and losses resulting from the revaluation at fair value at the end of each period are recognized in net income.

" Receivables are classified under "loans and receivables". They are recorded at cost, which, upon their initial measurement, is equal to their fair value. Subsequent measurements of receivables are recorded at amortized

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cost which usually corresponds to the amount initially recorded less any allowance for doubtful accounts.

" Payables and accruals, bank indebtedness and long term debt are classified as "other financial liabilities". They are initially measured at fair value and the gains and losses resulting from their subsequent measurement at amortized cost, at the end of each period, are recognized in net income.

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 Company's cash is held at a major institution. The long term debt has fixed interest rates. The bank indebtedness has interest at a floating rate which gives rise to a risk that its income (loss) and cash flows may be adversely affected by changes to interest rates. The Company manages its liquidity risk to ensure access to sufficient funds meet their needs. The fair value of these financial instruments approximates their carrying values, unless otherwise noted.

3. Future accounting pronouncements

International Financial Reporting Standards

The CICA has announced that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. The Canadian Accounting Standards Board (AcSB) subsequently released a ruling that qualifying entities with rate-regulated activities have

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the option to defer their adoption of IFRS until annual periods beginning on or after January 1, 2013. The Company has elected to adopt IFRS effective January 1, 2012.

IFRS will require increased financial statement disclosure. Although IFRS uses a conceptual framework similar to Canadian generally accepted accounting principles, there will be some differences in accounting policies that will need to be addressed. The Company is currently in the process of implementing its plan for the adoption of IFRS.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2011

4. Related party transactions 2011 2010

The Company had the following related party transactions:

Innisfil Energy Services Limited ("IESL") - affiliated company controlled by shareholder

Services billed	$ 8,652	$ 5,258

The Corporation of The Town of Innisfil ("Town") - shareholder

Interest expensed on debentures	$ 374,888	$ 455,574
Electrical services billed	2,123,914	1,862,558

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Professional services billed	-	9,600
Dividends paid	625,000	625,000
Municipal taxes	54,061	55,720
Other expenses	81,883	57,859
Contributed capital work billed		857,783

2,482,667

Balances outstanding at December 31:

Due to IESL	$ 8,512	$ -
Accrued interest, due to the Town	89,359	106,811
Note and debenture payable to the Town (Note 11)		3,666,000

4,382,000

Dividend payable to the Town, included in payables		312,500

156,250

Due from the Town, included in receivables		322,075

1,603,800

Due to the Town, included in payables	7,372	8,004

During the year, the Company provided financial, management and accounting services to IESL in the amount of $8,652 (2010 - $5,258). These transactions have been recorded in these financial statements at the carrying amounts, which were equal to their 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, $8,512, in payables, was due to IESL.

The Company provides electricity and services to the Town. These transactions

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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 $2,400,023 (2010 - $2,017,772), professional services in the amount of $nil (2010 - $9,600) and contributed capital of $857,783 (2010 - $2,482,667). At the end of the year, $322,075 (2010 - $1,603,800) was due for these services. During the year, the Company paid municipal taxes $54,061 (2010 - $55,720) and other expenses of $81,883 (2010 - $57,859) to the Town.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2011

5. Property and equipment 2011 2010

	Cost	Accumulated Amortization	Net Book Value	Net Book Value
Land	$ 474,819	$ -	$ 474,819	$ 474,819
Building and fixtures	739,632	273,912	465,720	493,421
Distribution station	4,358,561	2,322,875		

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2,035,686 2,017,979

Distribution system 49,028,643 24,039,688

24,988,955 23,213,202

System supervisory equipment 1,407,393 789,058

618,335 638,838

Other equipment 2,035,356 913,420

1,121,936 1,023,612

Computer hardware 515,305 400,081

115,224 157,591

CIP 110,616 - 110,616

-

Contributions in aid of construction (7,714,947)

(1,570,219) (6,144,728) (5,913,948)

$ 50,955,378 $ 27,168,815 $

23,786,563 $ 22,105,514

The amortization for property and equipment for the year was $1,984,467 (2010 - $1,938,289).

6. Intangible assets 2011 2010

	Cost	Accumulated Amortization	Net Book Value	Net Book Value
Land rights	$ 982,703	$ 557,986	$ 424,717	$ 445,653
Computer software	331,066	211,871		

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119,195		128,415		
	$	1,313,769	$ 769,857	$
543,912	$	574,068		

The amortization for intangible assets for the year was $97,139 (2010 - $117,661).

7. Long term investment

The long term investment is recorded at cost and consists of 16,894 preferred shares of a private company that mainly provides settlement services to the electric utilities of Ontario.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
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8. Regulatory assets and liabilities

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

	2011	2010
Regulatory assets		

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Regulatory assets approved for recovery	$ (8,150)	$ 494,780
Smart meters	2,153,227	2,143,559
Other	418,871	250,712
	$ 2,563,948	$ 2,889,051

Regulatory liabilities

Other	$ 96,899	$ 58,248
Retail settlement variance accounts	886,919	733,618
	$ 983,818	$ 791,866

Regulatory assets approved for recovery

On March 28, 2011, the OEB issued a decision on the disposition of Group I (RARA I and RARA II) regulatory asset recovery accounts into the regulatory asset recovery accounts 2010. In this decision the OEB approved the Group I accounts to be disposed of at the December 31, 2009 value including a projected interest amount up until April 30, 2011.

The OEB ordered the disposition of the Group I account balances over a one year period through the rates. All Group I accounts were transferred to the regulatory asset recovery 2011 accounts by June 30, 2011.

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. The RARA II includes

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retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest.

On April 26, 2009, the OEB announced its decision regarding the Company's OEB cost assessment, pension contribution, LV variance account, and accrued interest balances accumulated as of December 31, 2007. The OEB ordered that the approved balances be recovered on a straight-line basis over a four year period from May 1, 2009 to April 30, 2013. In the absence of rate regulation, the net effect on earnings would have increased by $502,931 (2010 - decrease of $140,426).

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
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8. Regulatory assets and liabilities (Continued)

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. To date amounts up to December 31, 2010 have been approved for recovery.

The Company has accumulated a net liability since this time. In the absence of rate regulation, the net effect on earnings would have increase by $153,301

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(2010 - $1,351,961).

Smart meters

In support of the Province of Ontario's decision to install smart meters throughout Ontario by 2010, the Company launched its smart meter installation program during the year and replaced approximately 100% of the meters as at December 31, 2010.

In connection with its smart meter initiatives, the Corporation has incurred costs amounting to $2,151,271 for the year ended December 31, 2011 (2010 - $1,975,232). These expenditures would otherwise have been recorded as property, plant and equipment under Canadian GAAP for unregulated businesses.

Smart meter amortization expense of $189,061 was deferred which otherwise would have been charged to amortization expense under Canadian GAAP for unregulated businesses (2010 - $101,425).

The smart meter customer revenues collected, stranded meters and other expenses were included in regulatory assets. In the absence of rate regulation, the net effect on earnings would have increased by $12,252 (2010 - decrease of $57,903).

Other regulatory assets and liabilities

These accounts include certain amounts deferred as required by OEB guidelines, including costs incurred to date for compliance with international financial reporting standards (IFRS) of $289,466 (2010 - $108,487). In the absence of

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rate regulation, the net effect on earnings would have decreased by $129,509 (2010 - $167,465).

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
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9. Bank indebtedness

The Company has a bank letter of credit outstanding for $938,146 (2010 - $938,146), as described in Note 13. The letter of credit bears interest at the prime rate of a Canadian chartered bank less .25% per annum.

The Company has bank indebtedness of $1,037,015 (2010 - $3,525,117), out of $4,000,000 credit limit. 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 and bears interest at the prime rate.

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Tax Year End: 2011-12-31

10. Short term debt

The Company has short term indebtedness with Toronto Dominion Bank of $4,000,000 (2010 - 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. The facility also bears interest at the prime rate, with no fixed term of repayment.

11. Long term debt

	2011	2010
Debentures payable to the Town	$ 3,666,000	$ 4,382,000
Term loan	2,029,825	2,096,644
Infrastructure Ontario Loan	2,500,000	-
	8,195,825	6,478,644
Less: current portion	1,026,314	785,000
	$ 7,169,511	$ 5,693,644

The debentures are payable to the Town and bear interest at various rates ranging from 9.5% to 9.75%. Principal payments are due annually on March 31 until 2015.

The term loan, due October 2030, is at a fixed interest rate of 4.53% until October 2020 and is secured by a general security agreement conveying first fixed and floating charges over the property, assets, rights and interests of the Company.

T2 BAR CODE RETURN

Name: INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED

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Tax Year End: 2011-12-31

The Infrastructure Ontario Debenture was converted from a construction loan to pay for the Smart Meter Initiative. The long term debt bears interest at 3.91% with semi-annual payments in February and August until 2026.

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

2012	1,026,314
2013	1,110,797
2014	1,203,179
2015	1,291,718
2016	250,198

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2011

12. Capital stock 2011 2010

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

13. Contingent liability

T2 BAR CODE RETURN

Name: INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED

BN: 89242 2817 RC 0001
Tax Year Start: 2011-01-01
Tax Year End: 2011-12-31

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, 2011, the Company provided prudential support using bank letters of credit of $938,146 (2010 - $938,146).

14. Other revenue

	2011	2010
Late payment charges	$ 104,841	$ 111,120
Interest	53,329	36,839
Pole rentals	157,442	161,381
Loss on disposal	(126,618)	-
SRED revenue	153,377	-
Miscellaneous service revenues	123,934	98,671
Miscellaneous non-operating income	77,967	30,292
	$ 544,272	$ 438,303

T2 BAR CODE RETURN

Name: INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED

BN: 89242 2817 RC 0001
Tax Year Start: 2011-01-01
Tax Year End: 2011-12-31

Innisfil Hydro Distribution Systems Limited
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15. Employee future benefits

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 7.4% to 10.7% of employee contributory earnings, depending upon the level of earnings. As a result, the Company made contributions in 2011 totalling $197,301 for the current service (2010 - $139,572).

Early retirement employee benefits

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. A liability has been setup for $36,192 (2010 - $32,383).

T2 BAR CODE RETURN

Name: INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED

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Tax Year Start: 2011-01-01
Tax Year End: 2011-12-31

16. 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.

Future taxes

Future income taxes are provided for temporary differences. The significant components of the Company's deductible (taxable) timing differences at year end are as follows:

	2011	2010
Future income tax asset:		
Property and equipment and intangibles	$ 1,740,000	$ 1,635,000
Future income tax asset (liability):		
Regulatory assets	$ 22,000	$ (17,000)
Provision for PILS:		
Current	$ 437,400	$ 825,000
Future (recovery)	(144,000)	(198,000)
	$ 293,400	$ 627,000

T2 BAR CODE RETURN

Name: INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED

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Tax Year End: 2011-12-31

Innisfil Hydro Distribution Systems Limited

Notes to the Financial Statements

December 31, 2011

17. Supplemental cash flow information 2011 2010

Change in non-cash operating working capital

Receivables	$ 904,515	$ (1,388,360)
Unbilled	537,895	(308,970)
Due to related party	(9,078)	(3,406)
Inventory	(138)	(106,642)
Payment in lieu of taxes	(531,573)	(14,126)
Prepaids	2,755	(88,224)
Payables and accruals	(779,051)	1,292,755
Customer credit balances and deposits	(62,426)	(198,439)
	$ 62,899	$ (815,412)

Supplemental cash flow information

Interest received	$ 53,329	$ 36,839
Interest paid	$ 652,535	$ 562,218
Payments in lieu of taxes paid	$ 774,030	$

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Name: INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED

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Tax Year Start: 2011-01-01
Tax Year End: 2011-12-31

828,379

18. 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 $24,000,000 per occurrence.

Innisfil Hydro Distribution Systems Limited
Notes to the Financial Statements
December 31, 2011

19. Capital disclosures

The Company's objectives when managing capital are:

o to safeguard the entity's ability to continue as a going concern, so that it can continue to provide returns for shareholders and benefits for other stakeholders, and

o to provide an adequate return to shareholders commensurately with the level of risk.

The Company sets the amount of capital in proportion to risk. The Company manages the capital structure and makes adjustments to it in the light of

T2 BAR CODE RETURN

Name: INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED

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changes in economic conditions and the risk characteristics of the underlying assets. In order to maintain or adjust the capital structure, the Company may adjust the amount of dividends paid to shareholders or return capital to shareholders, issue new shares, or sell assets to reduce debt. The Company is subject to quarterly reporting and bank review of its minimum interest coverage ratio of 1.2 to 1, and maximum debt to capitalization ratio of .6 to 1, in relation to the bank indebtedness. The Company is subject to annual from Infrastructure Ontario of its minimum debt service coverage ratio of 1 to 1, a maximum debt to capital ratio of 0.75 to 1, and a minimum current ratio of 1.1 to 1, in relation to the Infrastructure Ontario debenture.
Consistent with others in the industry, the Company monitors capital on the basis of the debt-to-equity ratio. This ratio is calculated as short and long term debt divided by equity. Short term debt is calculated as current notes and loans payable, as shown on the balance sheet. Long term debt is calculated as total long term debt, as shown on the balance sheet. Equity comprises all components of equity, share capital, development charges transferred to equity, and retained earnings.

20. Amortization of property and equipment and intangible assets

The amortization of property and equipment and intangible assets amounted to $2,081,606 (2010 - $2,055,950). The statement of earnings reflects $1,894,236 (2010 - $1,965,295) because the transportation and communication equipment amortization has been allocated to operations where the equipment was used. Amortization of $110,734 (2010 - $54,597) was mainly recorded as distribution expenses and $76,636 (2010 - $36,058) was recorded as capital expenditures and capitalized in property and equipment.

T2 BAR CODE RETURN

Name: INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED

BN: 89242 2817 RC 0001
Tax Year Start: 2011-01-01
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21. Comparative figures

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

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form Identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

Assets – lines 1000 to 2599

1060	5,867,834	1066	421,969	1120	428,004
1481	22,000	1484	300,372	1599	7,040,179
1600	474,819	1601	982,703	1602	-557,986
1680	739,632	1681	-273,912	1740	45,672,266
1741	-24,792,344	1774	2,364,371	1775	-1,401,010
1785	2,035,356	1786	-913,420	2008	52,269,147
2009	-27,938,672	2244	21,721	2420	2,563,948
2421	1,740,000	2589	4,325,669	2599	35,696,323

Liabilities – lines 2600 to 3499

2600	1,037,014	2620	4,372,280	2700	4,000,000
2860	97,871	2920	1,026,314	2961	648,368
3139	11,181,847	3140	7,169,511	3320	1,189,014
3450	8,358,525	3499	19,540,372		

Shareholder equity – lines 3500 to 3640

3500	10,852,444	3540	555,620	3600	4,747,887
3620	16,155,951	3640	35,696,323		

Retained earnings – lines 3660 to 3849

3660	4,262,027	3680	1,110,860	3700	-625,000
3849	4,747,887				

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

Description

Sequence number 0003 01

Revenue – lines 8000 to 8299

8000	29,203,939	8089	29,203,939	8094	490,943
8230	53,329	8299	29,748,211		

Cost of sales – lines 8300 to 8519

8320	21,570,056	8518	21,570,056	8519	7,633,883

Operating expenses – lines 8520 to 9369

8523	12,082	8670	1,894,236	8714	672,042
8810	1,806,007	9270	1,464,232	9273	925,296
9367	6,773,895	9368	28,343,951	9369	1,404,260

Farming revenue – lines 9370 to 9659

9659	0

Farming expenses – lines 9660 to 9899

9898	0

Extraordinary items and taxes – lines 9970 to 9999

9970	1,404,260	9990	437,400	9995	-144,000
9999	1,110,860				

Canada Revenue Agency | Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end (Year Month Day)
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				1,110,860 A
Add:				
Provision for income taxes – current		101	437,400	
Provision for income taxes – deferred		102	-144,000	
Interest and penalties on taxes		103	80	
Amortization of tangible assets		104	1,894,236	
Loss on disposal of assets		111	126,618	
Charitable donations and gifts from Schedule 2		112	290	
Scientific research expenditures deducted per financial statements		118	332,356	
Non-deductible meals and entertainment expenses		121	6,041	
Other reserves on lines 270 and 275 from Schedule 13		125	65,441	
Reserves from financial statements – balance at the end of the year		126	81,910	
	Subtotal of additions		2,800,372 ▶	2,800,372
Other additions:				
Miscellaneous other additions:				
600 Recovery of smart meter costs through rates 12(1)(x)		290	351,736	
603 Par. 12 (1)(x) contributions capitalized on F/S	521,407			
Inducement - ITA 12(1)x)	1,090			
Total	522,497	293	522,497	
604 Co-operative Education Tax Credit Claimed	13,524			
Apprenticeship tax credits	12,192			
Total	25,716	294	25,716	
	Subtotal of other additions	199	899,949 ▶	899,949
	Total additions	500	3,700,321 ▶	3,700,321
Deduct:				
Capital cost allowance from Schedule 8		403	2,279,128	
Cumulative eligible capital deduction from Schedule 10		405	23,633	
SR&ED expenditures claimed in the year from Form T661 (line 460)		411	241,497	
	Subtotal of deductions		2,544,258 ▶	2,544,258
Other deductions:				
Miscellaneous other deductions:				
700 Ss. 13(7.4) election re Contributions in aid of construction		390	521,407	
701 refund of previous tax interest paid		391	767	
703 SRED Revenue Accrued for Accounting	153,377			
Total	153,377	393	153,377	
704				
Total		394		
	Subtotal of other deductions	499	675,551 ▶	675,551
	Total deductions	510	3,219,809 ▶	3,219,809
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				1,591,372

T2 SCH 1 E (10)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 2

CHARITABLE DONATIONS AND GIFTS

Name of corporation	Business Number	Tax year-end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

- For use by corporations to claim any of the following:
  - charitable donations;
  - gifts to Canada, a province, or a territory;
  - gifts of certified cultural property;
  - gifts of certified ecologically sensitive land; or
  - additional deduction for gifts of medicine.
- The donations and gifts are eligible for a five-year carryforward.
- Use this schedule to show a credit transfer following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the *Income Tax Act*.
- For donations and gifts made after March 22, 2004, subsection 110.1(1.2) of the *Income Tax Act* provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- Under proposed changes, the eligible amount of a charitable gift is the amount by which the fair market value of the gift exceeds the amount of an advantage, if any, for the gift.
- Under proposed changes, a gift of medicine made after March 18, 2007, to qualifying organizations for activities outside of Canada, may be eligible for an additional deduction if the gift is an eligible medical gift. This additional deduction is calculated in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return.*
- For more information, see the *T2 Corporation – Income Tax Guide.*

Part 1 – Charitable donations

Charity/Recipient: VARIOUS — Amount ($100 or more only): 290

Subtotal: 290

Add: Total donations of less than $100 each:

Total donations in current tax year: 290

		Federal	Québec	Alberta
Charitable donations at the end of the previous tax year				
Deduct: Charitable donations expired after five tax years*	239			
Charitable donations at the beginning of the tax year	240			
Add:				
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250			
Total current-year charitable donations made (enter this amount on line 112 of Schedule 1)	210 290			
Subtotal (line 250 **plus** line 210)		290	290	290
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)	255			
Total charitable donations available		290 A	290	290
Deduct: Amount applied against taxable income (cannot be more than amount K in Part 2) (enter this amount on line 311 of the T2 return)	260	290	290	290
Charitable donations closing balance	280			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2010-12-31			
2nd prior year	2009-12-31			
3rd prior year	2008-12-31			
4th prior year	2007-12-31			
5th prior year	2006-12-31			
6th prior year*	2005-12-31			
7th prior year	2004-12-31			
8th prior year	2003-12-31			
9th prior year	2002-12-31			
10th prior year	2001-12-31			
11th prior year	2000-12-31			
12th prior year				
13th prior year				
14th prior year				
15th prior year				
16th prior year				
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*	0000-02-29			
Total (to line A)				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 2 – Calculation of the maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 % ..... 1,193,529 B

Taxable capital gains arising in respect of gifts of capital property included in Part 1** ..... 225 C

Taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01) ..... 227 D

The amount of the recapture of capital cost allowance in respect of charitable gifts 230

Proceeds of disposition, less outlays and expenses** ..... E

Capital cost** ..... F

Amount E or F, whichever is less 235

Amount on line 230 or 235, whichever is less ..... G

Subtotal (**add** amounts C, D, and G) H

Amount H **multiplied** by 25 % I

Subtotal (amount B **plus** amount I) 1,193,529 J

Maximum allowable deduction for charitable donations (enter amount A from Part 1, amount J, or net income for tax purposes, whichever is less) ..... 290 K

* For credit unions, this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts to Canada, a province, or a territory

Gifts to Canada, a province, or a territory at the end of the previous tax year			
Deduct: Gifts to Canada, a province, or a territory expired after five tax years	339		
Gifts to Canada, a province, or a territory at the beginning of the tax year	340		▶
Add: Gifts to Canada, a province, or a territory transferred on an amalgamation or the windup of a subsidiary	350		
Total current-year gifts made to Canada, a province, or a territory*	310		
		Subtotal (line 350 **plus** line 310)	
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	355		
Total gifts to Canada, a province, or a territory available			
Deduct: Amount applied against taxable income (enter this amount on line 312 of the T2 return).	360		
Gifts to Canada, a province, or a territory closing balance	380		

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

Part 4 – Gifts of certified cultural property

		Federal	Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year				
Deduct: Gifts of certified cultural property expired after five tax years*	439			
Gifts of certified cultural property at the beginning of the tax year	440			
Add: Gifts of certified cultural property transferred on an amalgamation or the windup of a subsidiary	450			
Total current-year gifts of certified cultural property	410			
Subtotal (line 450 **plus** line 410)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	455			
Total gifts of certified cultural property available				
Deduct: Amount applied against taxable income (enter this amount on line 313 of the T2 return)	460			
Gifts of certified cultural property closing balance	480			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2010-12-31			
2nd prior year	2009-12-31			
3rd prior year	2008-12-31			
4th prior year	2007-12-31			
5th prior year	2006-12-31			
6th prior year*	2005-12-31			
7th prior year	2004-12-31			
8th prior year	2003-12-31			
9th prior year	2002-12-31			
10th prior year	2001-12-31			
11th prior year	2000-12-31			
12th prior year				
13th prior year				
14th prior year				
15th prior year				
16th prior year				
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*	0000-02-29			
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 5 – Gifts of certified ecologically sensitive land

		Federal	Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year				
Deduct: Gifts of certified ecologically sensitive land expired after five tax years*	539			
Gifts of certified ecologically sensitive land at the beginning of the tax year	540			
Add: Gifts of certified ecologically sensitive land transferred on an amalgamation or the windup of a subsidiary	550			
Total current-year gifts of certified ecologically sensitive land	510			
Subtotal (line 550 **plus** line 510)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	555			
Total gifts of certified ecologically sensitive land available				
Deduct: Amount applied against taxable income (enter this amount on line 314 of the T2 return)	560			
Gifts of certified ecologically sensitive land closing balance	580			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Year of origin:		Federal	Québec	Alberta
1st prior year	2010-12-31			
2nd prior year	2009-12-31			
3rd prior year	2008-12-31			
4th prior year	2007-12-31			
5th prior year	2006-12-31			
6th prior year*	2005-12-31			
7th prior year	2004-12-31			
8th prior year	2003-12-31			
9th prior year	2002-12-31			
10th prior year	2001-12-31			
11th prior year	2000-12-31			
12th prior year				
13th prior year				
14th prior year				
15th prior year				
16th prior year				
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*	0000-02-29			
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 6 – Additional deduction for gifts of medicine

		Federal	Québec	Alberta
Additional deduction for gifts of medicine at the end of the previous tax year				
Deduct: Additional deduction for gifts of medicine expired after five tax years	639			
Additional deduction for gifts of medicine at the beginning of the tax year	640			
Add: Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650			
Additional deduction for gifts of medicine for the current year:				
Proceeds of disposition	602	1	1	1
Cost of gifts of medicine	601	2	2	2
Subtotal (line 1 **minus** line 2)		3	3	3
Line 3 **multiplied** by 50 %		4	4	4
Eligible amount of gifts	600	5	5	5

Federal

A _____ x (B _____ / C) = Additional deduction for gifts of medicine for the current year **610** _____

Québec

A _____ x (B _____ / C) = Additional deduction for gifts of medicine for the current year _____

Alberta

A _____ x (B _____ / C) = Additional deduction for gifts of medicine for the current year _____

where:

A is the **lesser** of line 2 and line 4

B is the eligible amount of gifts (line 600)

C is the proceeds of disposition (line 602)

Subtotal (line 650 **plus** line 610)				
Deduct: Adjustment for an acquisition of control	655			
Total additional deduction for gifts of medicine available				
Deduct: Amount applied against taxable income (enter this amount on line 315 of the T2 return)	660			
Additional deduction for gifts of medicine closing balance	680			

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2010-12-31			
2nd prior year	2009-12-31			
3rd prior year	2008-12-31			
4th prior year	2007-12-31			
5th prior year	2006-12-31			
6th prior year*	2005-12-31			
Total				

* These donations expired in the current year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2010-12-31	
2nd prior year	2009-12-31	
3rd prior year	2008-12-31	
4th prior year	2007-12-31	
5th prior year	2006-12-31	
6th prior year*	2005-12-31	
7th prior year	2004-12-31	
8th prior year	2003-12-31	
9th prior year	2002-12-31	
10th prior year	2001-12-31	
11th prior year	2000-12-31	
12th prior year		
13th prior year		
14th prior year		
15th prior year		
16th prior year		
17th prior year		
18th prior year		
19th prior year		
20th prior year		
21st prior year*		
Total	0000-02-29	

* These gifts expired in the current year.

T2 SCH 2 E (07)

Canada

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DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year-end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act*.
- A recipient corporation is connected with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- "X" under column A if dividend received from a foreign source (connected corporation only).
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

Do not include dividends received from foreign non-affiliates.

		Complete if payer corporation is connected			
Name of payer corporation (from which the corporation received the dividend) 200	A	B Enter 1 if payer corporation is connected 205	C Business Number of connected corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD 220	E Non-taxable dividend under section 83 230
Total (enter on line 402 of Schedule 1)					

Note: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation.

			Complete if payer corporation is connected		
F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)* 240	F1 Eligible dividends (included in column F)	F2	G Total taxable dividends paid by connected payer corporation (for tax year in column D) 250	H Dividend refund of the connected payer corporation (for tax year in column D)** 260	I Part IV tax before deductions F x 1 / 3 *** 270
					J
Total (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)					

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

*** For dividends received from connected corporations: Part IV tax = $\frac{\text{Column F x Column H}}{\text{Column G}}$

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1) . . . . . _____

Deduct:

Part IV.I tax payable on dividends subject to Part IV tax . . . . . 320 _____

Subtotal _____

Deduct:

Current-year non-capital loss claimed to reduce Part IV tax . . . . . 330 _____

Non-capital losses from previous years claimed to reduce Part IV tax . . . . . 335 _____

Current-year farm loss claimed to reduce Part IV tax . . . . . 340 _____

Farm losses from previous years claimed to reduce Part IV tax . . . . . 345 _____

Total losses applied against Part IV tax _____ x 1 / 3 = _____

Part IV tax payable (enter amount on line 712 of the T2 return) . . . . . 360 _____

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

	A Name of connected recipient corporation 400	B Business Number 410	C Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD 420	D Taxable dividends paid to connected corporations 430	D1 Eligible dividends (included in column D)
1	Town of Innisfil	12194 7188 RC0001	2011-12-31	625,000	

Note

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation.

Total 625,000

Total taxable dividends paid in the tax year to other than connected corporations . . . . . 450 _____

Eligible dividends (included in line 450) . . . . . 450a _____

Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column D above **plus** line 450) 460 625,000

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above) 625,000

Other dividends paid in the tax year (total of 510 to 540) . . . . . _____

Total dividends paid in the tax year 500 625,000

Deduct:

Dividends paid out of capital dividend account . . . . . 510 _____

Capital gains dividends . . . . . 520 _____

Dividends paid on shares described in subsection 129(1.2) . . . . . 530 _____

Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year . . . . . 540 _____

Subtotal _____ ▶ _____

Total taxable dividends paid in the tax year that qualify for a dividend refund 625,000

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SCHEDULE 4

CORPORATION LOSS CONTINUITY AND APPLICATION

Name of corporation	Business number	Tax year-end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending (TYE) before that time is deductible in computing taxable income in a TYE after that time. Also, no amount of capital loss incurred in a TYE after that time is deductible in computing taxable income of a TYE before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide*.
- File one completed copy of this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- Parts, sections, subsections, paragraphs, and subparagraphs mentioned in this schedule refer to the Act.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes . . . . . 1,591,372 A

Deduct: (increase a loss)

Net capital losses deducted in the year (enter as a positive amount) . . . . . a

Taxable dividends deductible under sections 112, 113(1), or subsection 138(6) . . . . . b

Amount of Part VI.1 tax deductible c

Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2) . . . . . d

Subtotal (total of amounts a to d) ▶ B

Subtotal (amount A **minus** amount B; if positive, enter "0") C

Deduct: (increase a loss)

Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions . . . . . D

Subtotal (amount C **minus** amount D) E

Add: (decrease a loss)

Current-year farm loss (whichever is less: the net loss from farming or fishing included in the income, or the non-capital loss before deducting the farm loss. Enter amount F on line 310) . . . . . F

Current-year non-capital loss (amount E **plus** amount F; if positive, enter "0"; if negative, enter amount G on line 110 as a positive) . G

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year . . . . . e

Deduct: Non-capital loss expired* . . . . . 100 f

Non-capital losses at the beginning of the tax year (amount e **minus** amount f) . . . . . 102 ▶ H

Add:

Non-capital losses transferred on an amalgamation or the wind-up of a subsidiary corporation . 105 g

Current-year non-capital loss (amount G above) . . . . . 110 h

Subtotal (amount g **plus** amount h) ▶ I

Subtotal (amount H **plus** amount I) J

* A non-capital loss expires as follows:

- after **7** tax years if it arose in a tax year ending before March 23, 2004;
- after **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss as follows:

- after **7** tax years if it arose in a tax year ending before March 23, 2004; and
- after **10** tax years if it arose in a tax year ending after March 22, 2004.

Part 1 – Non-capital losses (continued)

Amount J from page 1 _____

Deduct:

Other adjustments (includes adjustments for an acquisition of control)	150		i
Section 80 – Adjustments for forgiven amounts	140		j
Subsection 111(10) – Adjustments for fuel tax rebate			j.1
Non-capital losses of previous tax years applied in the current tax year (enter on line 331 of the T2 Return)	130		k
Current and previous year non-capital losses applied against current-year taxable dividends subject to Part IV tax (enter on lines 330 and 335 of Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*, respectively)	135		l
Subtotal (total of amounts i to l)		▶	K
Non-capital losses before any request for a carryback (amount J **minus** amount K)			L

Deduct – Request to carry back non-capital loss to:

First previous tax year to reduce taxable income	901		m
Second previous tax year to reduce taxable income	902		n
Third previous tax year to reduce taxable income	903		o
First previous tax year to reduce taxable dividends subject to Part IV tax	911		p
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		q
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		r
Total of requests to carry back non-capital losses to previous tax years (total of amounts m to r)		▶	M
Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M)	180		N

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200		a
Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	205		b
Subtotal (amount a **plus** amount b)		▶	A

Deduct:

Other adjustments (includes adjustments for an acquisition of control)	250		c
Section 80 – Adjustments for forgiven amounts	240		d
Subtotal (amount c **plus** amount d)		▶	B
Subtotal (amount A **minus** amount B)			C
Add: Current-year capital loss (from the calculation on Schedule 6)	210		D
Unused non-capital losses that expired in the tax year*			e
Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year**			f
Enter amount e or f, whichever is less	215		
ABILs expired as non-capital loss: line 215 **divided** by 0.500000	220		E
Subtotal (total of amounts C to E)			F

Note

If there has been an amalgamation or a windup of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary. Add all these amounts and enter the total on line 220 above.

* If the losses were incurred in a tax year ending before March 23, 2004, enter the losses from the 8th previous tax year. If the losses were incurred in a tax year ending after March 22, 2004, and before 2006, enter the losses from the 11th previous tax year. Enter the losses from the 21st previous tax year if the losses were incurred in a tax year ending after 2005. Enter the part that was not used in previous years and the current year on line e.

** If the losses were incurred in a tax year ending before March 23, 2004, enter the losses from the 8th previous tax year. If the losses were incurred in a tax year ending after March 22, 2004, enter the losses from the 11th previous tax year. Enter the full amount on line f.

Part 2 – Capital losses (continued)

Amount F from page 2 _____

Deduct: Capital losses from previous tax years applied against the current-year net capital gain (see Note 1) ..... 225 _____ G

Capital losses before any request for a carryback (amount F **minus** amount G) _____ H

Deduct – Request to carry back capital loss to (see Note 2):

	Capital gain (100%)		Amount carried back (100%)	
First previous tax year	_____	951	_____	g
Second previous tax year	16,656	952	_____	h
Third previous tax year	_____	953	_____	i
Subtotal (total of amounts g to i)			_____ ▶	_____ I

Closing balance of capital losses to be carried forward to future tax years (amount H **minus** amount I) 280 _____ J

Note 1

To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the purpose of current-year tax, enter the amount from line 225 **multiplied** by 50% on line 332 of the T2 return.

Note 2

On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, **multiply** this amount by the 50% inclusion rate.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year ..... _____ a

Deduct: Farm loss expired* ..... 300 _____ b

Farm losses at the beginning of the tax year (amount a **minus** amount b) ..... 302 _____ ▶ _____ A

Add:

Farm losses transferred on the amalgamation or the windup of a subsidiary corporation ..... 305 _____ c

Current-year farm loss ..... 310 _____ d

Subtotal (amount c **plus** amount d) _____ ▶ _____ B

Subtotal (amount A **plus** amount B) _____ C

Deduct:

Other adjustments (includes adjustments for an acquisition of control) ..... 350 _____ e

Section 80 – Adjustments for forgiven amounts ..... 340 _____ f

Farm losses of previous tax years applied in the current tax year (enter on line 334 of the T2 Return) ..... 330 _____ g

Current and previous year farm losses applied against current-year taxable dividends subject to Part IV tax (enter on lines 340 and 345 of Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*, respectively) ..... 335 _____ h

Subtotal (total of amounts e to h) _____ ▶ _____ D

Farm losses before any request for a carryback (amount C **minus** amount D) _____ E

Deduct – Request to carry back farm loss to:

First previous tax year to reduce taxable income ..... 921 _____ i

Second previous tax year to reduce taxable income ..... 922 _____ j

Third previous tax year to reduce taxable income ..... 923 _____ k

First previous tax year to reduce taxable dividends subject to Part IV tax ..... 931 _____ l

Second previous tax year to reduce taxable dividends subject to Part IV tax ..... 932 _____ m

Third previous tax year to reduce taxable dividends subject to Part IV tax ..... 933 _____ n

Subtotal (total of amounts i to n) _____ ▶ _____ F

Closing balance of farm losses to be carried forward to future tax years (amount E **minus** amount F) 380 _____ G

* A farm loss expires as follows:

- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business . . . . . 485 _____ A

Minus the deductible farm loss:

(amount A above _____ – $2,500) **divided** by 2 = _____ a

Amount a or $ 6,250 , whichever is less . . . . . _____ ▶ _____ b

2,500 c

Subtotal (amount b **plus** amount c) 2,500 ▶ 2,500 B

Current-year restricted farm loss (amount A **minus** amount B; enter amount C on line 410) _____ C

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year . . . . . _____ d

Deduct: Restricted farm loss expired* . . . . . 400 _____ e

Restricted farm losses at the beginning of the tax year (amount d **minus** amount e) . . . . . 402 _____ ▶ _____ D

Add:

Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation . . . . . 405 _____ f

Current-year restricted farm loss (enter on line 233 of Schedule 1) . . . . . 410 _____ g

Subtotal (amount f **plus** amount g) _____ ▶ _____ E

Subtotal (amount D **plus** amount E) _____ F

Deduct:

Restricted farm losses from previous tax years applied against current farming income (enter on line 333 of the T2 Return) . . . . . 430 _____ h

Section 80 – Adjustments for forgiven amounts . . . . . 440 _____ i

Other adjustments . . . . . 450 _____ j

Subtotal (total of amounts h to j) _____ ▶ _____ G

Restricted farm losses before any request for a carryback (amount F **minus** amount G) _____ H

Deduct – Request to carry back restricted farm loss to:

First previous tax year to reduce farming income . . . . . 941 _____ k

Second previous tax year to reduce farming income . . . . . 942 _____ l

Third previous tax year to reduce farming income . . . . . 943 _____ m

Subtotal (total of amounts k to m) _____ ▶ _____ I

Closing balance of restricted farm losses to be carried forward to future tax years (amount H **minus** amount I) 480 _____ J

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

* A restricted farm loss expires as follows:

- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Part 5 – Listed personal property losses

Continuité des pertes sur des biens meubles déterminés et demande de report rétrospectif

Listed personal property losses at the end of the previous tax year			a
Deduct: Listed personal property loss expired after seven tax years	500		b
Listed personal property losses at the beginning of the tax year (amount a **minus** amount b)	502	▶	A
Add: Current-year listed personal property loss (from Schedule 6)	510		B
Subtotal (amount A **plus** amount B)			C
Deduct:			
Previous year personal property losses applied in the current tax year against listed personal property gains (enter on line 655 of Schedule 6)	530		c
Other adjustments	550		d
Subtotal (amount c **plus** amount d)		▶	D
Listed personal property losses remaining before any request for a carryback (amount C **minus** amount D)			E
Deduct – Request to carry back listed personal property loss to:			
First previous tax year to reduce listed personal property gains	961		e
Second previous tax year to reduce listed personal property gains	962		f
Third previous tax year to reduce listed personal property gains	963		g
Subtotal (total of amounts e to g)		▶	F
Closing balance of listed personal property losses to be carried forward to future tax years (amount E **minus** amount F)	580		G

Part 7 – Limited partnership losses

Current-year limited partnership losses

	1 Partnership identifier 600	2 Tax year ending YYYY/MM/DD 602	3 Corporation's share of limited partnership loss 604	4 Corporation's at-risk amount 606	5 Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses 608	6 Column 4 **minus** column 5 (if negative, enter "0")	7 Current-year limited partnership losses (column 3 **minus** 6) 620
1	Enerconnect	2011-12-31					

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from previous tax years that may be applied in the current year

	1 Partnership identifier 630	2 Tax year ending YYYY/MM/DD 632	3 Limited partnership losses at the end of the previous tax year 634	4 Corporation's at-risk amount 636	5 Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses 638	6 Column 4 **minus** column 5 (If negative, enter "0")	7 Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6) 650
1	Enerconnect	2011-12-31					

Continuity of limited partnership losses that can be carried forward to future tax years

	1 Partnership identifier 660	2 Limited partnership losses at the end of the previous tax year 662	3 Limited partnership losses transferred on an amalgamation or the windup of a subsidiary 664	4 Current-year limited partnership losses (from column 620) 670	5 Limited partnership losses applied in the current year (cannot be more than column 650) 675	6 Current year limited partnership losses closing balance to be carried forward to future years (662 + 664 + 670 – 675) 680
1	Enerconnect					

Total (enter this amount on line 335 of the T2 return)

Note

If you have any current–or previous–year losses, enter your partnership identifier on line 600, 630, or 660.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . . 190 Yes ☐

Further to a winding-up of a subsidiary, the portion of a non-capital loss, restricted farm loss, farm loss, or limited partnership loss from a wholly-owned subsidiary is deemed to be the loss of a parent from its tax year starting after the commencement of the winding-up.

Note

This election is only applicable for wind-ups under 88(1) that are reported on Schedule 24, *First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent*, and the deemed provision is only for the tax years that start after the commencement of the wind-up.

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TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

SCHEDULE 5

Corporation's name	Business Number	Tax year-end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations*.
- For more information, see the *T2 Corporation – Income Tax Guide*.
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☐	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, *or* **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
1,591,082		1,591,082	150,679

Ontario basic income tax (from Schedule 500) 270 186,919

Deduct: Ontario small business deduction (from schedule 500) 402 36,240

Subtotal 150,679 ▶ 150,679 A6

Add:

Surtax re Ontario small business deduction (from Schedule 500) 272
Ontario additional tax re Crown royalties (from Schedule 504) 274
Ontario transitional tax debits (from Schedule 506) 276
Recapture of Ontario research and development tax credit (from Schedule 508) 277

Subtotal ▶ B6

Subtotal (amount A6 **plus** amount B6) 150,679 C6

Deduct:

Ontario resource tax credit (from Schedule 504) 404
Ontario tax credit for manufacturing and processing (from Schedule 502) 406
Ontario foreign tax credit (from Schedule 21) 408
Ontario credit union tax reduction (from Schedule 500) 410
Ontario transitional tax credits (from Schedule 506) 414
Ontario political contributions tax credit (from Schedule 525) 415

Subtotal ▶ D6

Subtotal (amount C6 **minus** amount D6) (if negative, enter "0") 150,679 E6

Deduct: Ontario research and development tax credit (from Schedule 508) 416 16,127

Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0") 134,552 F6

Deduct: Ontario corporate minimum tax credit (from schedule 510) 418

Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0") 134,552 G6

Add:

Ontario corporate minimum tax (from Schedule 510) 278
Ontario special additional tax on life insurance corporations (from Schedule 512) 280
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies) 282

Subtotal ▶ H6

Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6) 134,552 I6

Deduct:

Ontario qualifying environmental trust tax credit 450
Ontario co-operative education tax credit (from Schedule 550) 452 13,524
Ontario apprenticeship training tax credit (from Schedule 552) 454 12,192
Ontario computer animation and special effects tax credit (from Schedule 554) 456
Ontario film and television tax credit (from Schedule 556) 458
Ontario production services tax credit (from Schedule 558) 460
Ontario interactive digital media tax credit (from Schedule 560) 462
Ontario sound recording tax credit (from Schedule 562) 464
Ontario book publishing tax credit (from Schedule 564) 466
Ontario innovation tax credit (from Schedule 566) 468
Ontario business-research institute tax credit (from Schedule 568) 470
Other Ontario tax credits . . . . . .

Subtotal 25,716 ▶ 25,716 J6

Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) 290 108,836 K6
(if a credit, enter a negative amount) Include this amount on line 255.

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	255	108,836

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1		14,750,482			0		14,750,482	4	0	0	590,019	14,160,463
2.	8		729,943	166,204		0	83,102	813,045	20	0	0	162,609	733,538
3.	10		609,913	297,131		0	148,566	758,478	30	0	0	227,543	679,501
4.	12		23,844	73,245		0	36,623	60,466	100	0	0	60,466	36,623
5.	45	Computer Equipment and Softwa	10,167			0		10,167	45	0	0	4,575	5,592
6.	47	Electrical Energy Distribution Equ	13,661,840	3,328,197		89,297	1,619,450	15,281,290	8	0	0	1,222,503	15,678,237
7.	50	Computer Equipment Acquired A	12,557	16,388		0	8,194	20,751	55	0	0	11,413	17,532
8.	47	WIP		110,615		0	55,308	55,307	8	0	0		110,615
		Totals	29,798,746	3,991,780		89,297	1,951,243	31,749,986				2,279,128	31,422,101

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (11)

Canada

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		3,991,780	
Additions for tax purposes – Schedule 8 leasehold improvements	+		
Operating leases capitalized for book purposes	+		
Capital gain deferred	+		
Recapture deferred	+		
Deductible expenses capitalized for book purposes – Schedule 1	+		
Smart meter additions for tax purposes	+	-65,463	
Total additions per books	=	3,926,317 ▶	3,926,317
Proceeds up to original cost – Schedule 8 regular classes		89,297	
Proceeds up to original cost – Schedule 8 leasehold improvements	+		
Proceeds in excess of original cost – capital gain	+		
Recapture deferred – as above	+		
Capital gain deferred – as above	+		
Pre V-day appreciation	+		
reg asset amortization in expense accounts for stranded m.	+	31,745	
Total proceeds per books	=	121,042 ▶	121,042
Depreciation and amortization per accounts – Schedule 1			– 1,894,236
Loss on disposal of fixed assets per accounts			– 126,618
Gain on disposal of fixed assets per accounts			+
Net change per tax return			= 1,784,421

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		23,430,939
Opening net book value	–	21,759,111
Net change per financial statements	=	1,671,828

If the amounts from the tax return and the financial statements differ, explain why below.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	Innisfil Energy Services Limited		86556 4595 RC0001	3					
2.	Town of Innisfil		NR	1					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide.*
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") 200 341,931 A

Add:
Cost of eligible capital property acquired during the taxation year 222 1,981
Other adjustments 226
Subtotal (line 222 plus line 226) 1,981 x 3 / 4 = 1,486 B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . 228 x 1 / 2 = C

amount B minus amount C (if negative, enter "0") 1,486 ▶ 1,486 D

Amount transferred on amalgamation or wind-up of subsidiary . . . . . 224 E

Subtotal (add amounts A, D, and E) 230 343,417 F

Deduct:
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . . 242 7,742 G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . . . 244 H

Other adjustments . . . . . 246 I

(add amounts G,H, and I) 7,742 x 3 / 4 = 248 5,807 J

Cumulative eligible capital balance (amount F minus amount J) . . . . . 337,610 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business 249

amount K 337,610

less amount from line 249

Current year deduction . . . . . 337,610 x 7.00 % = 250 23,633 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 23,633 ▶ 23,633 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . 300 313,977 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)				N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988	400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)	401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3	
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	406		4	
Line 3 minus line 4 (if negative, enter "0")		▶	5	
Total of lines 1, 2 and 5			6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7	
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8	
Subtotal (line 7 plus line 8)	409	▶	9	
Line 6 minus line 9 (if negative, enter "0")		▶		O
Line N minus line O (if negative, enter "0")				P
		Line 5 _____ x 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")				R
		Amount R _____ x 2 / 3 =		S
Amount N or amount O, whichever is less				T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)	410			

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SCHEDULE 13

CONTINUITY OF RESERVES

Name of corporation	Business number	Tax year end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.
- File one completed copy of this schedule with the corporation's *T2 Corporation Income Tax Return.*
- For more information, see the *T2 Corporation Income Tax Guide.*

Part 1 – Capital gains reserves

	Description of property 001	Balance at the beginning of the year $ 002	Transfer on an amalgamation or the wind-up of a subsidiary $ 003	Add $	Deduct $	Balance at the end of the year $ 004
1						
	Totals	008	009			010

The amount from line 008 **plus** the amount from line 009 should be entered on line 880 of Schedule 6, *Summary of Dispositions of Capital Property.* The amount from line 010 should be entered on line 885 of Schedule 6.

Part 2 – Other reserves

Description	Balance at the beginning of the year $	Transfer on an amalgamation or the wind-up of a subsidiary $	Add $	Deduct $	Balance at the end of the year $
Reserve for doubtful debts ☐	110	115			120
Reserve for undelivered goods and services not rendered ☐	130	135			140
Reserve for prepaid rent ☐	150	155			160
Reserve for refundable containers ☐	190	195			200
Reserve for unpaid amounts ☐	210	215			220
Other tax reserves ☐	230 65,441	235		65,441	240
Totals	270 65,441	275		65,441	280

Enter "X" in the column above if the tax reserve has also been reported on the corporation's financial statements. This allows offsetting entries on Schedule 1, resulting in a zero effect on net income for tax purposes.

The amount from line 270 **plus** the amount from line 275 should be entered on line 125 of Schedule 1, *Net Income (Loss) for Income Tax Purposes,* as an addition. The amount from line 280 should be entered on line 413 of Schedule 1 as a deduction.

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	reversal of settlement variance			81,910		81,910
2						
	Reserves from Part 2 of Schedule 13					
	Totals			81,910		81,910

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . 025 — Year Month Day

Enter the calendar year to which the agreement applies . . . . . 050 — Year: 2011

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . 075 — 1 Yes ☐ 2 No ☒

	1 Names of associated corporations 100	2 Business Number of associated corporations 200	3 Asso-ciation code 300	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400
1	INNISFIL HYDRO DISTRIBUTION SYSTEMS LIN	89242 2817 RC0001	1	500,000	100.0000	500,000
2	Innisfil Energy Services Limited	86556 4595 RC0001	4			
3	Town of Innisfil	NR	4			
				Total	100.0000	500,000 A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

T2 SCH 23 (09)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 31

INVESTMENT TAX CREDIT – CORPORATIONS

General information

1. For use by a corporation that during a tax year:
   - earned an investment tax credit (ITC);
   - is claiming a deduction against its Part I tax payable;
   - is claiming a refund of credit earned during the current tax year;
   - is claiming a carryforward of credit from previous tax years;
   - is transferring a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act;*
   - is requesting a credit carryback; or
   - is subject to a recapture of ITC.
2. References to parts, sections, and subsections on this schedule are from the federal *Income Tax Act* and the federal *Income Tax Regulations*. References to interpretation bulletins and information circulars are to the latest versions.
3. The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
4. Investments or expenditures, as defined in subsection 127(9) and Part XLVI of the federal *Income Tax Regulations*, that earn the ITC are:
   - qualified property (Parts 4 to 7);
   - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). Complete and file Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
   - pre-production mining expenditures (Parts 18 to 20);
   - apprenticeship job creation expenditures (Parts 21 to 23); and
   - child care spaces expenditures (Parts 24 to 28).
5. Attach a completed copy of this schedule with the *T2 Corporation Income Tax Return.*
6. For more information on ITCs, see the section called "Investment Tax Credit" in the *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates*, and its related Special Release. Also, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures.*
7. For information on SR&ED, see Interpretation Bulletin IT-151 (**consolidated**), *Scientific Research and Experimental Development Expenditures*; Information Circular 86-4, *Scientific Research and Experimental Development*; Brochure RC4472, *Overview of the Scientific Research and Experimental Development Program (SR&ED) Tax Incentive Program*; Brochure RC4467, *Support for your R&D in Canada* and T4088, *Guide to Form T661 Scientific Research and Experimental Development (SR&ED) Expenditures Claim.*

Detailed information

1. For the purpose of this schedule, **"investment"** means:
   The capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
2. An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
3. Property acquired has to be "available for use" before a claim for an ITC can be made.
4. Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which the expenditures or capital costs were incurred.
5. Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITC's is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 of the Act is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068-1, 2010 Supplement to the 2006 T4068, Guide for the T5013 Partnership Information Return.
6. For SR&ED expenditures, the expression "in Canada" includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.

Name of corporation	Business Number	Tax year-end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

Part 1 – Investments, expenditures and percentages

	Specified percentage
Investments	
Qualified property acquired primarily for use in Newfoundland and Labrador, Prince Edward Island, Nova Scotia, New Brunswick, the Gaspé Peninsula, or a prescribed offshore region	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate.	
If you are a corporation that is not a CCPC that incurred qualified expenditures for SR&ED in any area in Canada	20 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures	10 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? **101** 1 Yes ☐ 2 No ☒

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and the taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? **102** 1 Yes ☐ 2 No ☒

Contributions to agricultural organizations for SR&ED **103** _____

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations*. Enter contributions on line 350 of Part 8.

QUALIFIED PROPERTY

Part 4 – Eligible investments for qualified property from the current tax year

	CCA* class number 105	Description of investment 110	Date available for use 115	Location used (province or territory) 120	Amount of investment 125
1.					

* CCA: capital cost allowance

Total investment – enter in formula on line 240 in Part 5

Part 5 – Calculation of current-year credit and account balances – ITC from investments in qualified property

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations 210

Credit expired 215

Subtotal ▶

ITC at the beginning of the tax year 220

Add:

Credit transferred on amalgamation or wind-up of subsidiary 230

ITC from repayment of assistance 235

Total current-year credit: total of column 125 _____ x 10 % = 240

Credit allocated from a partnership 250

Subtotal ▶

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B1 in Part 30) 260

Credit carried back to the previous year(s) (from Part 6) A

Credit transferred to offset Part VII tax liability 280

Subtotal ▶

Credit balance before refund B

Deduct:

Refund of credit claimed on investments from qualified property (from Part 7) 310

ITC closing balance of investments from qualified property 320

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day		
1st previous tax year				Credit to be applied	901
2nd previous tax year				Credit to be applied	902
3rd previous tax year				Credit to be applied	903

Total (enter on line A in Part 5)

Part 7 – Calculation of refund for qualifying corporations on investments from qualified property

Current-year ITCs (total of lines 240 and 250 in Part 5) C

Credit balance before refund (amount B from Part 5) D

Refund (40 % of amount C or D, whichever is less) E

Enter amount E or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures

Current expenditures (from line 557 on Form T661)	342,242		
Add:			
Contributions to agricultural organizations for SR&ED*			
Current expenditures (including contributions to agricultural organizations for SR&ED at line 103 in Part 3)* (from line 557 on Form T661)	342,242 ▶	350	342,242
Capital expenditures (from line 558 on Form T661)		360	
Repayments made in the year (from line 560 on Form T661)		370	
Total (this must equal the amount from line 570 on Form T661)*		380	342,242

* Do not file form T661 if you are only claiming contributions made to agricultural organizations for SR&ED.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC.

Note: A CCPC that calculates SR&ED expenditure limit, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? 385 1 Yes [X] 2 No [ ]

Complete lines 390 and 398, if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied). 390

Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million. 398

* If either of the tax years referred to at line 390 is less than 51 weeks, multiply the taxable income by the following result: 365 divided by the number of days in these tax years.

Part 10 – Calculation of SR&ED expenditure limit for a CCPC

For stand-alone corporations:

Calculation 1A: Tax year ends before January 1, 2010.

[($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . . _____

Calculation 1: Tax year starts after December 31, 2009.

[($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . . _____

Calculation 2: Tax year straddles January 1, 2010.

EE + [(FF **minus** EE) x (GG **divided by** HH)] where, ... _____

EE = [($7,000,000 **minus** (10**A**)) x (($40,000,000 **minus B**) **divided by** $40,000,000)];

FF = [($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];

GG = number of days **in** the tax year after December 31, 2009;

HH = number of days in the tax year.

Amount A **408** _____ Amount B **409** _____

A = the greater of:

- $400,000; and
- your taxable income for the last tax year* ending in the previous calendar year (tax years ending in 2008) (prior to any loss carry-backs applied).

B = the taxable capital employed in Canada for the last tax year ending in the previous calendar year (tax years ending in 2008) minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million.

* If any of the tax years referred to in **A** above are less than 51 weeks, gross up the taxable incomes for those tax years by the ratio that 365 is of the number of days in those tax years. Use these grossed up amounts when calculating the expenditure limit.

Enter the amount from Calculation 1A, 1 or 2, whichever is applicable _____ G*

For associated corporations:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 . . . . . **400** _____ H*

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Line G or H _____ x $\frac{\text{Number of days in the tax year}}{365}$ 365 = ... _____ I

Your SR&ED expenditure limit for the year (enter the amount from line G, H, or I, whichever applies) . . . . . **410** _____

* Amount G or H cannot be more than $3,000,000.

Part 11 – Calculation of investment tax credits on SR&ED expenditures

Enter whichever is less: current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10)*	420		x	35 % =		J
Line 350 minus line 410 (if negative, enter "0")	430	342,242	x	20 % =	68,448	K
Line 410 minus line 350 (if negative, enter "0")			L			
Enter whichever is less: capital expenditures (line 360 from Part 8) or line L above*	440		x	35 % =		M
Line 360 minus line L (if negative, enter "0")	450		x	20 % =		N

Repayments (amount from line 370 in Part 8)

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

460		x	35 % =		
480		x	20 % =		
			Total	▶	O

Current-year SR&ED ITC (total of lines J, K, M, N, and O; enter on line 540 in Part 12) 68,448

* For corporations that are not CCPCs, enter "0" on lines J and M.

Part 12 – Calculation of current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year				
Deduct:				
Credit deemed as a remittance of co-op corporations	510			
Credit expired	515			
		Subtotal	▶	
ITC at the beginning of the tax year	520			
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	530			
Total current-year credit	540	68,448		
Credit allocated from a partnership	550			
		Subtotal	68,448 ▶	68,448
Total credit available				68,448
Deduct:				
Credit deducted from Part I tax (enter on line B2 in Part 30)	560	68,448		
Credit carried back to the previous year(s) (from Part 13)			P	
Credit transferred to offset Part VII tax liability	580			
		Subtotal	68,448 ▶	68,448
Credit balance before refund				Q
Deduct:				
Refund of credit claimed on expenditures of SR&ED (from Part 14 or 15, whichever applies)	610			
ITC closing balance on SR&ED	620			

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	
				Total (enter on line P in Part 12)		

Part 14 – Calculation of refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . 650 1 Yes ☐ 2 No ☒

Credit balance before refund (amount Q from Part 12) . . . . . R

Current-year ITC (lines 540 plus 550 from Part 12 **minus** line O from Part 11) . . . . . S

Refundable credits (amount R or S, whichever is less)* . . . . . T

Amount J from Part 11 . . . . . U

Subtract: Amount T or U, whichever is less V

Net amount (if negative, enter "0") . . . . . W

Amount W _____ x 40 % X

Add: Amount V . . . . . Y

Refund of ITC (amounts X **plus** Y – enter this, or a lesser amount, on line 610 in Part 12) . . . . . Z

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC on line Z.

Part 15 – Calculation of refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined in Part 2.

Credit balance before refund (amount Q from Part 12) . . . . . AA

Amount J from Part 11 . . . . . BB

Subtract: Amount AA or BB, whichever is less CC

Net amount (if negative, enter "0") . . . . . DD

Amount M from Part 11 . . . . . EE

Amount DD or EE, whichever is less _____ x 40 % . . . . . FF

Add : Amount CC above . . . . . GG

Refund of ITC (amounts FF **plus** GG) . . . . . HH

Enter HH, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

RECAPTURE – SR&ED

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

	Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter this amount on line LL in Part 17) _____ LL

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at line JJ in Part 16.

	A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**
1.			

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line JJ below.

	D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred **750**	F Amount from column D or E, whichever is less
1.			

Subtotal (enter this amount on line MM in Part 17) _____ JJ

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line KK below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line NN in Part 17) **760** _____ KK

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from line II in Part 16		LL
Recaptured ITC for calculation 2 from line JJ in Part 16 above		MM
Recaptured ITC for calculation 3 from line KK in Part 16 above		NN
Total recapture of SR&ED investment tax credit – Add lines LL, MM and NN Enter amount OO at line A1 in Part 29.		OO

PRE-PRODUCTION MINING

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

	List of minerals 800
1.	

For each of the minerals reported in column 800 above, identify each project, mineral title, and mining division where title is registered. If there is no mineral title, identify the project and mining division only.

	Project name 805	Mineral title 806	Mining division 807
1.			

Pre-production mining expenditures *

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810	PP
Geological, geophysical, or geochemical surveys	811	QQ
Drilling by rotary, diamond, percussion, or other methods	812	RR
Trenching, digging test pits, and preliminary sampling	813	SS

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820	TT
Sinking a mine shaft, constructing an adit, or other underground entry	821	UU

Other pre-production mining expenditures incurred in the tax year:

	Description 825	Amount 826
1.		

Add amounts at column 826 ▶ VV

Total pre-production mining expenditures (add amounts PP to VV) 830

Deduct: Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above 832

Excess (line 830 minus line 832) (if negative, enter "0") WW

Add: Repayments of government and non-government assistance 835 XX

Pre-production mining expenditures (amount WW plus amount XX) YY

* A pre-production mining expenditure is defined under subsection 127(9).

Part 19 – Calculation of current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations 841

Credit expired 845

Subtotal

ITC at the beginning of the tax year 850

Add:

Credit transferred on amalgamation or wind-up of subsidiary 860

Expenditures from line YY in Part 18: 870 _____ x 10 % = 880

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B3 in Part 30) 885

Credit carried back to the previous year(s) (from Part 20) _____ CCC

Subtotal

ITC closing balance from pre-production mining expenditures 890

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day
1st previous tax year			
2nd previous tax year			
3rd previous tax year			

Credit to be applied 921

Credit to be applied 922

Credit to be applied 923

Total (enter on line CCC in Part 19)

APPRENTICESHIP JOB CREATION

Part 21 – Calculation of total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice. Attach additional schedules if more space is needed.

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
1.					

Total current-year credit (enter at line 640)

* Net of any other government or non-government assistance received or to be received.

Part 22 – Calculation of current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year			
Deduct:			
Credit deemed as a remittance of co-op corporations	612		
Credit expired after 20 tax years	615		
Subtotal		▶	
ITC at the beginning of the tax year	625		
Add:			
Credit transferred on amalgamation or wind-up of subsidiary	630		
ITC from repayment of assistance	635		
Total current-year credit (total of column 605)	640		
Credit allocated from a partnership	655		
Subtotal		▶	
Total credit available			
Deduct:			
Credit deducted from Part I tax (enter on line B4 in Part 30)	660		
Credit carried back to the previous year(s) (from Part 23)		DDD	
Subtotal		▶	
ITC closing balance from apprenticeship job creation expenditures	690		

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	931	
2nd previous tax year				Credit to be applied	932	
3rd previous tax year				Credit to be applied	933	
				Total (enter on line DDD in Part 22)		

CHILD CARE SPACES

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specifled child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year 715 EEE

Add: Specified child care start-up expenditures from the current tax year 705 FFF

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) GGG

Deduct: Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line GGG) 725 HHH

Excess (amount GGG **minus** amount HHH) (if negative, enter "0") III

Add: Repayments of government and non-government assistance 735 JJJ

Total eligible expenditures for child care spaces (amount III **plus** amount JJJ) 745

* CCA: capital cost allowance

Part 25 – Calculation of current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (line 745)			x	25 %	=	KKK
Number of child care spaces	755		x $	10,000	=	LLL
ITC from child care spaces expenditures (amount KKK or LLL, whichever is less)						MMM

Part 26 – Calculation of current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year			
Deduct:			
Credit deemed as a remittance of co-op corporations	765		
Credit expired after 20 tax years	770		
Subtotal		▶	
ITC at the beginning of the tax year	775		
Add:			
Credit transferred on amalgamation or wind-up of subsidiary	777		
Total current-year credit (amount MMM above)	780		
Credit allocated from a partnership	782		
Subtotal		▶	
Total credit available			
Deduct:			
Credit deducted from Part I tax (enter on line B5 in Part 30)	785		
Credit carried back to the previous year(s) (from Part 27)			NNN
Subtotal		▶	
ITC closing balance from child care spaces expenditures	790		

Part 27 – Request for carryback of credit from child care space expenditures

	Year	Month	Day			
1st previous tax year	2010-12-31			Credit to be applied	941	
2nd previous tax year	2009-12-31			Credit to be applied	942	
3rd previous tax year	2008-12-31			Credit to be applied	943	
				Total (enter on line NNN in Part 26)		

RECAPTURE – CHILD CARE SPACES

Part 28 – Calculating the recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a))	792		ZZZ
In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:			
The amount that can reasonably be considered to have been included in the original ITC	795		
25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property	797		
Amount from line 795 or line 797, whichever is less			OOO

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line PPP below.

Corporate partner's share of the excess of ITC	799		PPP
Total recapture of child care spaces investment tax credit – Add lines ZZZ, OOO, and PPP. Enter amount QQQ on line A2 in Part 29.			QQQ

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC from line OO in Part 17		A1
Recaptured child care spaces ITC from line QQQ in Part 28 above		A2
Total recapture of investment tax credit – Add lines A1 and A2. Enter amount A3 on line 602 of the T2 return.		A3

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5)		B1
ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12)	68,448	B2
ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19)		B3
ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22)		B4
ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26)		B5
Total ITC deducted from Part I tax (add lines B1, B2, B3, B4, and B5). Enter amount B6 at line 652 of the T2 return.	68,448	B6

Privacy Act, Personal Information Bank number CRA PPU 047

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 99 Cur. or cap. R&D for ITC

Current year

	Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
	68,448	68,448			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				
2001-12-31				
2000-12-31				*
Total				*

B+C+D+G

Total ITC utilized 68,448

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	Town of Innisfil	12194 7188 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

On: 2011-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? ☐ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year	100	4,413,054	A
Taxable income for the year (DICs enter "0") *	110	1,591,082	B
Income for the credit union deduction * (amount E in Part 3 of Schedule 17)	120		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less *	130		
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income *	140		
Subtotal (**add** lines 120, 130, and 140)	▶		C
Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0")	150	1,591,082	
After-tax income (line 150 x general rate factor for the tax year ** 0.7)	190	1,113,757	D
Eligible dividends received in the tax year	200		
Dividends deductible under section 113 received in the tax year	210		
Subtotal (**add** lines 200 and 210)	▶		E
GRIP addition:			
Becoming a CCPC (line PP from Part 4)	220		
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230		
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240		
Subtotal (**add** lines 220, 230, and 240)	▶	290	F
Subtotal (**add** lines A, D, E, and F)		5,526,811	G
Eligible dividends paid in the previous tax year	300		
Excessive eligible dividend designations made in the previous tax year	310		
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.			
Subtotal (line 300 **minus** line 310)	▶		H
GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative)	490	5,526,811	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)	560		
GRIP at the end of the tax year (line 490 **minus** line 560) Enter this amount on line 160 of Schedule 55.	590	5,526,811	

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2010-12-31

Taxable income before specified future tax consequences from the current tax year	2,830,475	J1	
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)		K1	
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less		L1	
Aggregate investment income (line 440 of the T2 return)		M1	
Subtotal (**add** lines K1, L1, and M1)	▶		N1
Subtotal (line J1 **minus** line N1) (if negative, enter "0")	2,830,475 ▶	2,830,475	O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E **in** Part 3 of Schedule 17) . . . Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R1

Aggregate investment income (line 440 of the T2 return) S1

Subtotal (**add** lines Q1, R1, and S1) ▶ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ▶ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") V1

GRIP adjustment for specified future tax consequences to the first previous tax year

(line V1 **multiplied by** the general rate factor for the tax year 0.7) **500**

Second previous tax year 2009-12-31

Taxable income before specified future tax consequences from the current tax year 2,118,349 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L2

Aggregate investment income (line 440 of the T2 return) 18,453 M2

Subtotal (**add** lines K2, L2, and M2) 18,453 ▶ 18,453 N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 2,099,896 ▶ 2,099,896 O2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R2

Aggregate investment income (line 440 of the T2 return) S2

Subtotal (**add** lines Q2, R2, and S2) ▶ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ▶ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") V2

GRIP adjustment for specified future tax consequences to the second previous tax year

(line V2 **multiplied by** the general rate factor for the tax year 0.7) **520**

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2008-12-31

Taxable income before specified future tax consequences from the current tax year 1,614,738 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L3

Aggregate investment income (line 440 of the T2 return) 96,949 M3

Subtotal (**add** lines K3, L3, and M3) 96,949 ▶ 96,949 N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 1,517,789 ▶ 1,517,789 O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R3

Aggregate investment income (line 440 of the T2 return) S3

Subtotal (**add** lines Q3, R3, and S3) ▶ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") ▶ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") V3

GRIP adjustment for specified future tax consequences to the third previous tax year

(line V3 **multiplied** by the general rate factor for the tax year 0.7) **540**

Total GRIP adjustment for specified future tax consequences to previous tax years:

(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . . AA

Eligible dividends paid by the corporation in its last tax year . . . . . BB

Excessive eligible dividend designations made by the corporation in its last tax year CC

Subtotal (line BB **minus** line CC) ▶ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

(line AA **minus** line DD) . . . . . EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . ☐ Post amalgamation . . . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . . FF

The corporation's money on hand immediately before the end of its previous/last tax year . . . . . GG

Unused and unexpired losses at the end of the corporation's previous/last tax year:

Non-capital losses . . . . .
Net capital losses . . . . .
Farm losses . . . . .
Restricted farm losses . . . . .
Limited partnership losses . . . . .

Subtotal ▶ HH

Subtotal (**add** lines FF, GG, and HH) II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . . JJ

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . . KK

All the corporation's reserves deducted in its previous/last tax year LL

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . . MM

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . . NN

Subtotal (**add** lines JJ, KK, LL, MM, and NN) ▶ OO

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0") . . . . . PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year.

0.68	x	number of days in the tax year before January 1, 2010 / number of days in the tax year	365	.....	=		QQ
0.69	x	number of days in the tax year in 2010 / number of days in the tax year	365	.....	=		RR
0.7	x	number of days in the tax year in 2011 / number of days in the tax year	365 / 365	.....	=	0.70000	SS
0.72	x	number of days in the tax year after December 31, 2011 / number of days in the tax year	365	.....	=		TT

General rate factor for the tax year (total of lines QQ to TT) ..... 0.70000 UU

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SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references on this schedule are to the federal *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Do not use this area

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3		625,000	
Total taxable dividends paid in the tax year	100	625,000	
Total eligible dividends paid in the tax year	150		A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")	160	5,526,811	B
Excessive eligible dividend designation (line 150 **minus** line 160)			C
Deduct:			
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*	180		D
Subtotal (amount C **minus** amount D)			E
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount E **multiplied** by 20 %)	190		F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3			
Total taxable dividends paid in the tax year	200		
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)			G
Deduct:			
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*	280		H
Subtotal (amount G **minus** amount H)			I
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount I **multiplied** by 20 %)	290		J

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

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SCHEDULE 500

ONTARIO CORPORATION TAX CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only and does not have to be filed with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic rate of tax for the year

Number of days in the tax year before July 1, 2010 / Number of days in the tax year		365	x	14.00 %	=	% A1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	181	365	x	12.00 %	=	5.95068 % A2
Number of days in the tax year after June 30, 2011 / Number of days in the tax year	184	365	x	11.50 %	=	5.79726 % A3

Ontario basic rate of tax for the year (total of rates A1 to A3) 11.74794 ▶ 11.74794 % A4

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . . 1,591,082 B

Ontario basic income tax: amount B **multiplied by** Ontario basic rate of tax for the year (rate A4 from Part 1) . . . . . 186,919 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit, in addition to Ontario basic income tax, or has Ontario corporate minimum tax, Ontario special additional tax on life insurance corporations or Ontario capital tax payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)		1,591,372 1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)		1,591,082 2
Federal business limit before the application of subsection 125(5.1) * (amount from line 410 of the T2 return)	_____ x _____ =	500,000 3
Enter the least of amounts 1, 2, and 3	line 4 on page 4 of the T2 return	500,000 D
Ontario domestic factor: Ontario taxable income ** / taxable income earned in all provinces and territories ***	1,591,082.00 / 1,591,082 =	1.00000 E

Amount D x amount E: 500,000 a

Ontario taxable income (amount B from Part 2): 1,591,082 b

Ontario small business income (lesser of amount a and amount b) ..... 500,000 F

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	_____ / 365	x 8.50 %	= _____ %	G1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	181 / 365	x 7.50 %	= 3.71918 %	G2
Number of days in the tax year after June 30, 2011 / Number of days in the tax year	184 / 365	x 7.00 %	= 3.52877 %	G3

OSBD rate for the year (total of rates G1 to G3) ..... 7.24795 % G4

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G4) ..... 36,240 H

Enter amount H on line 402 of Schedule 5.

* For 2011 and later tax years, enter the amount from line 410 of the T2 return on line 3 of this schedule. Otherwise, complete the calculation for this line.

** Enter amount B from Part 2.

*** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Calculation of surtax re Ontario small business deduction

Complete this part if the corporation is claiming the OSBD and its adjusted taxable income, **plus** the adjusted taxable income of each corporation with which the corporation was associated during its tax year, is greater than $500,000. If the corporation is a member of an associated group, complete Schedule 501, *Ontario Adjusted Taxable Income of Associated Corporations to Determine Surtax re Ontario Small Business Deduction.*

Note: For days in the tax year after June 30, 2010, the small business surtax rate is 0%. You do not have to complete this part if the corporation's tax year begins after June 30, 2010.

Adjusted taxable income * I

Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501) . . . . J

Aggregate adjusted taxable income (amount I **plus** amount J) . . . . . ▶ K

Deduct:

Ontario business limit 500,000

Subtotal (amount K **minus** Ontario business limit) (if negative, enter "0" on this line and on line P) L

Small business surtax rate for the year:

$$\frac{\text{Number of days in the tax year before July 1, 2010}}{\text{Number of days in the tax year}} \quad \frac{}{365} \times 4.25\,\% = \,\% \; M$$

Amount L **multiplied by** % on line M = ... N

Amount N $\times \frac{\text{Ontario small business income (amount F from Part 3)}}{500{,}000}$ $\frac{}{500{,}000} =$ . . . . O

Surtax re Ontario small business deduction: lesser of amount O and OSBD (amount H from Part 3) . . . . . P

Enter amount P on line 272 of Schedule 5.

* Adjusted taxable income is equal to the corporation's taxable income or taxable income earned in Canada for the year **plus** the amount of the corporation's adjusted Crown royalties for the year **minus** the amount of the corporation's notional resource allowance for the year (from Schedule 504, *Ontario Resource Tax Credit and Ontario Additional Tax re Crown Royalties*).

If the tax year of the corporation is less than 51 weeks, **multiply** the adjusted taxable income of the corporation for the year by 365 and **divide** by the number of days in the tax year.

Part 5 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Lesser of amount D and amount b from Part 3 . . . . . 500,000 Q

$$\frac{\text{Surtax payable (amount P from Part 4)}}{\text{Ontario domestic factor (amount E from Part 3) x OSBD rate (rate G6 from Part 3)} \quad 7.24795\,\%} \quad \frac{}{0.07248} = \; R$$

Note: Enter "0" on line R for tax years beginning after June 30, 2010.

Ontario adjusted small business income (amount Q **minus** amount R) (if negative, enter "0") . . . . . 500,000 S

Enter amount S on line U in Part 6 or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 6 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17		T
Deduct:		
Ontario adjusted small business income (amount S from Part 5)		U
Subtotal (amount T **minus** amount U) (if negative, enter "0")		V
OSBD rate for the year (rate G6 from Part 3)	7.24795 %	
Amount V **multiplied** by the OSBD rate for the year		W
Ontario domestic factor (amount E from Part 3)	1.00000	X
Ontario credit union tax reduction (amount W **multiplied** by amount X)		Y

Enter amount Y on line 410 of Schedule 5.

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SCHEDULE 508

ONTARIO RESEARCH AND DEVELOPMENT TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

- Use this schedule to:
  - calculate an Ontario research and development tax credit (ORDTC);
  - claim an ORDTC earned in the tax year or carried forward from any of the 20 previous tax years that are a tax year ending after December 31, 2008, to reduce Ontario corporate income tax payable in the current tax year;
  - carry back an ORDTC to reduce Ontario corporate income tax payable in any of the three previous tax years, but not to a tax year that ends before January 1, 2009;
  - add an ORDTC that was allocated to the corporation by a partnership of which it was a member;
  - transfer an ORDTC after an amalgamation or windup; or
  - calculate a recapture of the ORDTC.
- The ORDTC is a 4.5% non-refundable tax credit on eligible expenditures incurred by a corporation in a tax year that ends after December 31, 2008.
- An eligible expenditure is an expenditure for a permanent establishment in Ontario of a corporation, that is a qualified expenditure for the purposes of section 127 of the federal *Income Tax Act* for scientific research and experimental development (SR&ED) carried on in Ontario.
- Only corporations that are not exempt from Ontario corporate income tax and none of whose income is exempt income can claim the ORDTC.
- Attach a completed copy of this schedule to the *T2 Corporation Income Tax Return.*

Part 1 – Ontario SR&ED expenditure pool

Total eligible expenditures incurred by the corporation in Ontario in the tax year	100	358,369 A	
Deduct: Government assistance, non-government assistance, or a contract payment for eligible expenditures	105	B	
Net eligible expenditures for the tax year (amount A **minus** amount B) (if negative, enter "0")		358,369 C	
Add: Eligible expenditures transferred to the corporation by another corporation	110	D	
Subtotal (amount C **plus** amount D)		358,369 ▶	358,369 E
Deduct: Eligible expenditures the corporation transferred to another corporation	115		F
Ontario SR&ED expenditure pool (amount E **minus** amount F) (if negative, enter "0")	120		358,369 G

Part 2 – Calculation of the current part of the ORDTC

Ontario SR&ED expenditure pool (amount G in Part 1)	358,369	x	4.50 % =	200	16,127 H
ORDTC allocated to a corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *				205	I
* If there is a disposal or change of use of eligible property, see Part 6					
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure other than for first term or second term shared-use equipment	210	x	4.50 % =	215	J
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure for first term or second term shared-use equipment	220	x 1 / 4 =	x 4.50 % =	225	K
Current part of the ORDTC (total of amounts H to K)				230	16,127 L

Part 3 – Calculation of ORDTC available for deduction and ORDTC balance

ORDTC balance at the end of the previous tax year			M
Deduct: ORDTC expired after 20 tax years	300		N
ORDTC at the beginning of the tax year (amount M **minus** amount N)	305		O
Add:			
ORDTC transferred on amalgamation or windup	310		P
Current part of ORDTC (amount L in Part 2)		16,127	Q

Are you waiving all or part of the current part of the ORDTC? 315 Yes 1 ☐ No 2 ☒

If you answered **yes** at line 315, enter the amount of the tax credit waived on line 320.

If you answered **no** at line 315, enter "0" on line 320.

Deduct: Waiver of the current part of the ORDTC	320			R
Subtotal (amount Q **minus** amount R)		16,127	▶ 16,127	S
ORDTC available for deduction (total of amounts O, P and S)		16,127	▶ 16,127	T
Deduct:				
ORDTC claimed * (Enter amount U on line 416 of Schedule 5, *Tax Calculation Supplementary – Corporations*)		16,127		U
ORDTC carried back to a previous tax year (from Part 4)				V
Subtotal (amount U **plus** amount V)		16,127	▶ 16,127	W
ORDTC balance at the end of the tax year (amount T **minus** amount W)	325			X

* This amount cannot be more than the lesser of the following amounts:
- ORDTC available for deduction (amount T); or
- Ontario corporate income tax payable before the ORDTC and the Ontario corporate minimum tax credit (amount from line E6 of Schedule 5).

Part 4 – Request for carryback of tax credit

	Year	Month	Day			
1st previous tax year	2010-12-31			Credit to be applied	901	
2nd previous tax year	2009-12-31			Credit to be applied	902	
3rd previous tax year	2008-12-31			Credit to be applied	903	
				Total (enter amount on line V in Part 3)		

Part 5 – Analysis of tax credit available for carryforward by tax year of origin

You can complete this part to show all the credits from preceding tax years available for carryforward, by year of origin. This will help you determine the amount of credit that could expire in following years.

Tax year of origin (earliest tax year first) Year Month Day	Credit available
2000-12-31	

Tax year of origin (earliest tax year first) Year Month Day		Credit available
2001-12-31		
2002-12-31		
2003-12-31		
2004-12-31		
2005-12-31		
2006-12-31		
2007-12-31		
2008-12-31		
2009-12-31		
2010-12-31		
2011-12-31	Current tax year	

Total (equals line 325 in Part 3)

The amount available from the 20th preceding tax year will expire after this year. When you file your return for the next year, you will enter the expired amount on line 300 of Schedule 508 for that year.

Part 6 – Calculation of a recapture of ORDTC

You will have a recapture of ORDTC in a tax year when you meet **all** of the following conditions:

- you acquired a particular property in the current year or in any of the 20 previous tax years if the ORDTC was earned in a tax year ending after 2008;
- you claimed the cost of the property as an eligible expenditure for the ORDTC;
- the cost of the property was included in computing your ORDTC or was subject to an agreement made under subsection 127(13) of the federal Act to transfer qualified expenditures and section 42 of the *Taxation Act, 2007* (Ontario) applied; and
- you disposed of the property or converted it to commercial use in a tax year ending after December 31, 2008. You also meet this condition if you disposed of or converted to commercial use a property which incorporates the particular property previously referred to.

Note: The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED in Ontario. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical federal investment tax credit (ITC) rate * of the original user in Calculation 1 below.

You have to report the recapture on Schedule 5 for the year in which you disposed of the property or converted it to commercial use. If the corporation is a member of a partnership, report its share of the recapture.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

* Federal ITC in calculations 1 and 2 should be determined without reference to paragraph (e) of the definition **investment tax credit** in subsection 127(9) of the federal Act.

Calculation 1 – If you meet all of the above conditions

	Y Amount of federal ITC you originally calculated for the property you acquired, or the original user's federal ITC where you acquired the property from a non-arm's length party, as described in the note above 700	Z Amount calculated using the federal ITC rate *at* the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	AA Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter amount BB, on line KK in Part 7) BB

Calculation 2 – If the corporation is deemed by subsection 42(1) of the *Taxation Act, 2007* (Ontario) to have transferred all or part of the eligible expenditure to another corporation as a consequence of an agreement described in subsection 127(13) of the federal Act complete Calculation 2. Otherwise, enter nil on line II.

	CC The rate percentage that the transferee used to determine its federal ITC for a qualified expenditure that was transferred under an agreement under subsection 127(13) of the federal Act 720	DD The proceeds of disposition of the property if you dispose of it to a person at arm's length; or, in any other case, the fair market value of the property at conversion or disposition 730	EE The amount, if any, already provided for in Calculation 1 (this allows for the situation where only part of the cost of a property is transferred for an agreement under subsection 127(13) of the federal Act) 740
1.			

	FF Amount determined by the formula (CC x DD) – EE (using the columns above)	GG The federal ITC earned by the transferee for the qualified expenditure that was transferred 750	HH Amount from column FF or GG, whichever is less
1.			

Subtotal (enter amount II on line LL below) ____ II

Calculation 3

As a member of a partnership, you will report your share of the ORDTC of the partnership after the ORDTC has been reduced by the amount of the recapture. If this is a positive amount, you will report it on line 205 in Part 2. However, if the partnership does not have enough ORDTC otherwise available to offset the recapture, then the amount by which reductions to the ORDTC exceeds additions (the excess) will be determined and reported on line JJ.

Corporate partner's share of the excess of ORDTC (enter amount JJ at line NN below) . . . . . 760 ____ JJ

Part 7 – Total recapture of ORDTC

Recaptured federal ITC for Calculation 1 (amount from line BB) . . . . . ____ KK

Recaptured federal ITC for Calculation 2 (amount from line II above) . . . . . ____ LL

Amount KK **plus** amount LL . . . . . ____ x 23.56 % = ____ MM

Add: Corporate partner's share of the excess of ORDTC for Calculation 3 (amount from line JJ above) . . . . . ____ NN

Recapture of ORDTC (amount MM **plus** amount NN) (enter amount OO on line 277 of Schedule 5) . . . . . ____ OO

Schedule A - Worksheet for eligible expenditures incurred by the corporation in Ontario for the current taxation year

This worksheet allows you to report the amount of eligible expenditures entered on Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* which represents eligible expenditures as defined in section 127 of the *Income Tax Act* (ITA) with regard to scientific research and experimental development (SR&ED) **carried on in Ontario and attributable to a permanent establishment in Ontario of a corporation.**

Data on the worksheet is calculated based on the amounts on Form T661, but will have to be adjusted according to the rules of Ontario, if applicable, in particular when the corporation has had a permanent establishment in more than one jurisdiction. This data will be used when calculating Schedule 508 and Schedule 566.

Enter the breakdown between current and capital expenditures

		Current Expenditures		Capital Expenditures	
Total expenditures for SR&ED		332,356			
Add					
• payment of prior years' unpaid expenses (other than salary or wages)	+				
• prescribed proxy amount (Enter "0" if you use the traditional method)	+	26,013			
• expenditures on shared-use equipment			+		
• other additions	+		+		
Subtotal	=	358,369	=		
Less					
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	−				
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	−				
• prescribed expenditures not allowed by regulations	−		−		
• other deductions	−		−		
• non-arm's length transactions					
– expenditures for non-arm's length SR&ED contracts	−				
– purchases (limited to costs) of goods and services from non-arm's length suppliers	−		−		
Subtotal	=	358,369 I	=		II
Total eligible expenditures incurred by the corporation in Ontario in the tax year (add amount I and II)			=	358,369	III

Enter amount III on line 100 of Schedule 508.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	**120** Ontario Corporation No.
Ontario	2000-10-05	7284940

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
2073	COMMERCE PARK DR	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
INNISFIL	ON	CA	L9S 4A2

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 [1] If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 COOLEDGE (Last name) **451** LAURIE ANN (First name)

454 _____ (Middle name(s))

460 [2] Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 ☐ Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number | **530** Street name/Rural route/Lot and Concession number | **540** Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town) | **570** Province/state | **580** Country | **590** Postal/zip code

Part 6 – Language of preference

600 ☐ Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	120 Telephone number including area code
LAURIE ANN COOLEDGE	(705) 431-4321

Is the claim filed for a CETC earned through a partnership?* . . . . . 150 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . 160 _____

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . 170 _____ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . 200 1 Yes ☒ 2 No ☐
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . 210 1 Yes ☐ 2 No ☒

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * 300 2,022,661

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\% - \left[5\% \times \frac{\text{amount on line 300 minus } \$\ 400{,}000}{\$\ 200{,}000} \right]$$

Eligible percentage for determining the eligible amount . . . . . 310 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\% - \left[5\% \times \frac{\text{amount on line 300 minus } \$\ 400{,}000}{\$\ 200{,}000} \right]$$

Eligible percentage for determining the eligible amount . . . . . 312 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
1.	GEORGIAN COLLEGE	ELECTRICAL ENGINEERING
2.	GEORGIAN COLLEGE	ELECTRICAL ENGINEERING
3.	GEORGIAN COLLEGE	ELECTRICAL ENGINEERING
4.	GEORGIAN COLLEGE	ELECTRICAL ENGINEERING
5.	GEORGIAN COLLEGE	ELECTRICAL ENGINEERING
6.	GEORGIAN COLLEGE	ELECTRICAL ENGINEERING
7.		

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
1.	MORGAN BARLOW	2011-01-04	2011-05-02
2.	NICOLAS DORAN	2011-08-31	2011-12-23
3.	JOSEPH JOHNSON	2011-05-02	2011-09-02
4.	SARA LEEST	2011-01-28	2011-04-29
5.	MEGHAN LENNOX	2011-04-27	2011-09-02
6.	HEATHER WILSON	2011-09-01	2011-12-23

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
7.			

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		10.000 %	9,348	25.000 %		16
2.		10.000 %	8,363	25.000 %		16
3.		10.000 %	10,005	25.000 %		18
4.		10.000 %	6,811	25.000 %		13
5.		10.000 %	10,574	25.000 %		18
6.		10.000 %	8,992	25.000 %		16
7.		10.000 %		25.000 %		

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	2,337	3,000	2,337		2,337
2.	2,091	3,000	2,091		2,091
3.	2,501	3,000	2,501		2,501
4.	1,703	3,000	1,703		1,703
5.	2,644	3,000	2,644		2,644
6.	2,248	3,000	2,248		2,248
7.					

Ontario co-operative education tax credit (total of amounts in column K) 500 — 13,524 L

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L _____ x percentage on line 170 in Part 1 _____ % = ... M

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 552

ONTARIO APPRENTICESHIP TRAINING TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	89242 2817 RC0001	2011-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. Before March 27, 2009, the maximum credit for each apprentice is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship. After March 26, 2009, the maximum credit for each apprentice is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. The maximum credit amount is prorated for an employment period of an apprentice that straddles March 26, 2009.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if incurred before March 27, 2009; and
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if incurred after March 26, 2009.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario); and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009* or the *Apprenticeship and Certification Act, 1998* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Make sure you keep a copy of the training agreement or contract of apprenticeship to support your claim. Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information (please print)

110 Name of person to contact for more information	120 Telephone number including area code
LAURIE ANN COOLEDGE	(705) 431-4321

Is the claim filed for an ATTC earned through a partnership? * . . . . . **150** 1 Yes ☐ 2 No ☒

If **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** _____

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . . **170** _____ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes ☒ 2 No ☐
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **210** 1 Yes ☐ 2 No ☒

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * 300 2,022,661

For eligible expenditures incurred before March 27, 2009:
- If line 300 is $400,000 or less, enter 30% on line 310.
- If line 300 is $600,000 or more, enter 25% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Specified percentage} = 30\% - \left[5\% \times \frac{\text{amount on line 300 minus } 400{,}000}{200{,}000} \right]$$

Specified percentage . . . . . 310 25.000 %

For eligible expenditures incurred after March 26, 2009:
- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\% - \left[10\% \times \frac{\text{amount on line 300 minus } 400{,}000}{200{,}000} \right]$$

Specified percentage . . . . . 312 35.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice that is in a qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
1.	434a	Powerline Technician	CHRISTOPHER LATOUF
2.	434a	Powerline Technician	MATTHEW COUSINS

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
1.	PC9361	2010-10-13	2011-01-01	2011-12-31
2.	D23969	2007-03-21	2011-01-01	2011-03-21

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Part 4 – Calculation of the Ontario apprenticeship training tax credit (continued)

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
1.		365	365	10,000
2.		80	80	2,192

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
1.		57,341	57,341	20,069
2.		23,872	23,872	8,355

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
1.	10,000		10,000
2.	2,192		2,192

Ontario apprenticeship training tax credit (total of amounts in column N) **500** 12,192 O

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O _____ x percentage on line 170 in Part 1 _____ % = ... _____ P

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, add the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 36 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 48 months of the registration date provided in column E.

Note 2: Maximum credit = ($5,000 x H1/365*) + ($10,000 x H2/365*)
* 366 days, if the tax year includes February 29

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures before March 27, 2009, must be for services provided by the apprentice during the first 36 months of the apprenticeship program.
For J2: Eligible expenditures after March 26, 2009, must be for services provided by the apprentice during the first 48 months of the apprenticeship program.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 x line 310) + (J2 x line 312)

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year.
Complete a **separate entry** for each repayment of government assistance.

ATTACHEMENT

Innisfil Hydro Distribution Systems Limited
December 31, 2011
Election under Subsection 13(7.4) of the Federal Income Tax Act

In accordance with the provisions of subsection 13(7.4) of the Federal Income Tax Act ("the Act"), the taxpayer hereby elects to include the receipt of $521,407 in contributions in aid of construction as a reduction to the original capital cost of the underlying property for which the assistance was received.

Adjustments to reflect this election have been made to reduce the undepreciated capital cost ("UCC") of the underlying property on Schedule 8 of the federal Income Tax Return.

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CENTRE FOR CO-OPERATIVE EDUCATION, INTERNSHIP AND CAREER SERVICES

January, 2012

Barb Cesarin and/or Finance Dept.
Innisfil Hydro
2073 Commerce Park Drive
Innisfil, ON
L9S 4A2

Re: Nicholas Doran

Georgian College confirms the above student(s) enrolled in **Electrical Engineering Technology-Automated Systems** program was employed by your company for the **Fall 2011** (Sept.-Dec.), work term. We certify that the work term(s) qualifies for the purpose of the Co-operative Education Tax Credit.

Additional information on the Educational Tax Credit can be found at
http://www.rev.gov.on.ca/english/credit/cetc/

Thank you for your support of the Co-operative Education Programs at Georgian College.

Sincerely,

Sean Elliott
Co-op Consultant-Employer Development
Engineering Technology
(705) 728-1968 ext. 5261
selliott@georgianc.on.ca

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October, 2011

Marj Stewart and/or Finance Dept.
Innisfil Hydro
2073 Commerce Park Dr.
Innisfil, ON
L9S 4A2

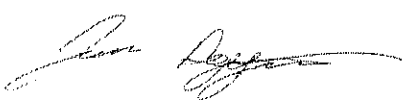
Re: Meghan Lennox

Georgian College confirms the above student(s) enrolled in **Business** program was employed by your company for the **Summer 2011** (May- Aug.), work term. We certify that the work term(s) qualifies for the purpose of the Co-operative Education Tax Credit.

Additional information on the Educational Tax Credit can be found at
http://www.rev.gov.on.ca/english/credit/cetc/

Thank you for your support of the Co-operative Education Programs at Georgian College.

Sincerely,



John Daggett
Co-op Consultant, Employer Development
Business General, Accounting, and Golf Management Programs
(705) 728-1968 ext. 1390
jdaggett@georgianc.on.ca

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October, 2011

Barb Cesarin and/or Finance Dept.
Innisfil Hydro
2073 Commerce Park Drive
Innisfil, ON
L9S 4A2

Re: Joseph Johnson

Georgian College confirms the above student(s) enrolled in **Electrical Engineering Technology-Automated Systems** program was employed by your company for the **Summer 2011** (May-Aug.), work term. We certify that the work term(s) qualifies for the purpose of the Co-operative Education Tax Credit.

Additional information on the Educational Tax Credit can be found at
http://www.rev.gov.on.ca/english/credit/cetc/

Thank you for your support of the Co-operative Education Programs at Georgian College.

Sincerely,

Nick O'Connell

Nick O'Connell
Co-op Consultant-Employer Development
Engineering Technology
(705) 728-1968 ext. 5261
nconnell@georgianc.on.ca

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May, 2011

Brenda Pinke and/or Finance Dept.
Innisfil Hydro
2073 Commerce Park Dr
Innisfil, ON
L9S 4A2

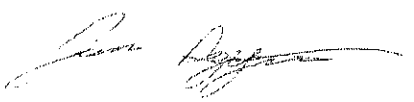
Re: Brittany Pollock

Georgian College confirms the above student(s) enrolled in **Business** program was employed by your company for the **Winter 2011** (Jan.- Apr.), work term. We certify that the work term(s) qualifies for the purpose of the Co-operative Education Tax Credit.

Additional information on the Educational Tax Credit can be found at
http://www.rev.gov.on.ca/english/credit/cetc/

Thank you for your support of the Co-operative Education Programs at Georgian College.

Sincerely,



John Daggett
Co-op Consultant, Employer Development
Business General, Accounting, and Golf Management Programs
(705) 728-1968 ext. 1390
jdaggett@georgianc.on.ca

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May, 2011

Barb Cesarin and/or Finance Dept.
Innisfil Hydro
2073 Commerce Park Dr
Innisfil, ON
L9S 4A2

Re: Sara Leest

Georgian College confirms the above student(s) enrolled in **Business** program was employed by your company for the **Winter 2011** (Jan.- Apr.), work term. We certify that the work term(s) qualifies for the purpose of the Co-operative Education Tax Credit.

Additional information on the Educational Tax Credit can be found at
http://www.rev.gov.on.ca/english/credit/cetc/

Thank you for your support of the Co-operative Education Programs at Georgian College.

Sincerely,

John Daggett
Co-op Consultant, Employer Development
Business General, Accounting, and Golf Management Programs
(705) 728-1968 ext. 1390
jdaggett@georgianc.on.ca

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Exhibit	Tab	Schedule	Appendix	Contents
5 – Cost of Capital and Rate of Return				
	1	1		Overview
		2		Capital Structure Deemed & Actual

OVERVIEW:

The purpose of this evidence is to summarize the method and cost of financing capital requirements for the 2013 test year.

Capital Structure:

IHDSL has a current deemed capital structure of 4% short term debt with a return of 1.33%, 56% long-term debt with a return of 7.28%, and 40% equity with a return of 8.01% as approved in the 2009 rate decision (EB-2008-0233).

IHDSL has prepared this rate application with a deemed capital structure of 56% Long Term Debt with a return of 5.11%, 4% Short Term Debt with a return of 2.08%, and 40% Equity with a return of 9.12%.

Return on Equity:

IHDSL is requesting a return on equity ("ROE") for the 2013 Test year of 9.12% in accordance with the Cost of Capital Parameter Updates for 2012 Cost of Service Applications issued by the OEB on March 3, 2012. IHDSL understands that the OEB will be finalizing the ROE for 2013 rates based on January 2013 market interest rate information. IHDSL's use of an ROE of 9.12% is without prejudice to any revised ROE that may be adopted by the OEB in early 2013.

COST OF DEBT:

Long Term Debt

IHDSL is requesting a return on Long Term Debt for the 2013 Test Year of 5.11%. IHDSL is currently paying rates varying from 4.05 to 4.53% on existing Long Term Loans negotiated with

TD Bank, rate of 3.91% for existing debentures negotiated with Infrastructure Ontario and a rate of 9.75% for existing debentures held by the Town of Innisfil to Royal Bank. In 2012 IHDSL will incur demand debt related to the various 2012 capital projects. In 2013, IHDSL anticipates a further increase to the demand load of $8.0m for the 2013 capital projects.

Short Term Debt

IHDSL is requesting a return on Short Term Debt for the 2013 Test year of 2.08% in accordance with the Cost of Capital Parameter Updates for 2012 Cost of Service Applications issued by the OEB on March 3, 2012. IHDSL understands that the OEB will be finalizing the return on short term debt for 2013 rates based on January 2013 market interest rate information. IHDSL's use of a Return on Short Term Debt of 2.087% is without prejudice to any revised Short Term Debt rate that may be adopted by the OEB in early 2013.

Rate Base and Rate of Return

Table 5.1.1 and Table 5.1.2 details IHDSL's debt and capital structure for 2009, 2010, 2011 and 2012 Bridge and 2013 Test Year Forecasts. Table 5.1.3 provides the details of the weighted average cost of debt for each of the years 2009, 2010, 2011 and the 2012 Bridge and Test Year Forecasts.

CAPITAL STRUCTURE

Table 5.1.1 – Deemed Capital Structure 2009 to 2013

Particulars	Capitalization Ratio		Cost Rate	Return
2009 Board Approved				
	(%)	($)	(%)	($)
Debt				
Long-term Debt	52.67%	$12,045,624	7.28%	$877,376
Short-term Debt	4.00% (1)	$914,800	1.33%	$12,167
Total Debt	56.7%	$12,960,423	6.86%	$889,543
Equity				
Common Equity	43.33%	$9,909,567	8.01%	$793,756
Preferred Shares		$ -		$ -
Total Equity	43.3%	$9,909,567	8.01%	$793,756
Total	100.0%	$22,869,990	7.36%	$1,683,299

Particulars	Capitalization Ratio		Cost Rate	Return
2009				
	(%)	($)	(%)	($)
Debt				
Long-term Debt	52.67%	$11,574,236	7.21%	$834,008
Short-term Debt	4.00% (1)	$879,000	1.33%	$11,691
Total Debt	56.7%	$12,453,236	6.79%	$845,699
Equity				
Common Equity	43.33%	$9,521,771	8.01%	$762,694
Preferred Shares		$ -		$ -
Total Equity	43.3%	$9,521,771	8.01%	$762,694
Total	100.0%	$21,975,007	7.32%	$1,608,392

Particulars	Capitalization Ratio		Cost Rate	Return
2010				
	(%)	($)	(%)	($)
Debt				
Long-term Debt	56.00%	$13,890,431	5.48%	$761,018
Short-term Debt	4.00% (1)	$992,174	1.33%	$13,196
Total Debt	60.0%	$14,882,605	5.20%	$774,214
Equity				
Common Equity	40.00%	$9,921,736	8.01%	$794,731
Preferred Shares		$ -		$ -
Total Equity	40.0%	$9,921,736	8.01%	$794,731
Total	100.0%	$24,804,341	6.33%	$1,568,945

Table 5.1.1 – Deemed Capital Structure 2009 to 2013 (con't)

2011						
	(%)		($)	(%)		($)
Debt						
Long-term Debt	56.00%		$15,272,323	5.18%		$790,846
Short-term Debt	4.00%	(1)	$1,090,880	1.33%		$14,509
Total Debt	60.0%		$16,363,203	4.92%		$805,355
Equity						
Common Equity	40.00%		$10,908,802	8.01%		$873,795
Preferred Shares			$ -			$ -
Total Equity	40.0%		$10,908,802	8.01%		$873,795
Total	100.0%		$27,272,005	6.16%		$1,679,150

Particulars	**Capitalization Ratio**	**Cost Rate**	**Return**

2012 Bridge						
	(%)		($)	(%)		($)
Debt						
Long-term Debt	56.00%		$17,767,759	5.23%		$928,532
Short-term Debt	4.00%	(1)	$1,269,126	1.33%		$16,879
Total Debt	60.0%		$19,036,885	4.97%		$945,411
Equity						
Common Equity	40.00%		$12,691,256	8.01%		$1,016,570
Preferred Shares			$ -			$ -
Total Equity	40.0%		$12,691,256	8.01%		$1,016,570
Total	100.0%		$31,728,141	6.18%		$1,961,981

Particulars	**Capitalization Ratio**	**Cost Rate**	**Return**

2013 Test						
	(%)		($)	(%)		($)
Debt						
Long-term Debt	56.00%		$21,286,134	5.11%		$1,088,189
Short-term Debt	4.00%	(1)	$1,520,438	2.08%		$31,625
Total Debt	60.0%		$22,806,572	4.91%		$1,119,814
Equity						
Common Equity	40.00%		$15,204,382	9.12%		$1,386,640
Preferred Shares			$ -			$ -
Total Equity	40.0%		$15,204,382	9.12%		$1,386,640
Total	100.0%		$38,010,954	6.59%		$2,506,454

Table 5.1.2 – Debt Instruments 2009-2013

Year 2009

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	
1	Notes Payable	Town of Innsfil	Affiliated	Variable Rate	31-Dec-07	3	$ 2,107,444	1.13%	$ 23,814.12	
2	Debentures	Town of Innsfil	Third-Party	Fixed Rate	1-Apr-95	20	$ 5,032,000	9.75%	$ 490,620.00	
3									$ -	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 7,139,444	7.21%	$ 514,434.12	

Year 2010

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	
1	Bank Loan	Toronto Dominion Ba	Third-Party	Fixed Rate	29-Oct-10	20	$ 2,096,644	4.53%	$ 28,420.01	
2	Debentures	Town of Innsfil	Third-Party	Fixed Rate	1-Apr-95	20	$ 4,382,000	9.75%	$ 427,245.00	
3	Construction Loan	Infrastructure Ontario	Third-Party	Variable Rate	15-Apr-10	Demand	$ 2,500,000	1.45%	$ 36,250.00	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 8,978,644	5.48%	$ 491,915.01	

Year 2011

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	
1	Bank Loan	Toronto Dominion Ba	Third-Party	Fixed Rate	29-Oct-10	20	$ 2,029,826	4.53%	$ 91,951.12	
2	Debentures	Town of Innsfil	Third-Party	Fixed Rate	1-Apr-95	20	$ 3,666,000	9.75%	$ 357,435.00	
3	Debentures	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	15	$ 2,500,000	3.91%	$ 97,750.00	
4	Demand Load	Toronto Dominion Ba	Third-Party	Variable Rate	1-Jan-11	Demand	$ 4,000,000	2.11%	$ 84,400.00	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 12,195,826	5.18%	$ 631,536.12	

Year 2012

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	
1	Bank Loan	Toronto Dominion Ba	Third-Party	Fixed Rate	29-Oct-10	20	$ 1,960,178	4.53%	$ 88,796.06	
2	Debentures	Town of Innsfil	Third-Party	Fixed Rate	1-Apr-95	20	$ 2,876,000	9.75%	$ 280,410.00	
3	Debentures	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	15	$ 2,333,333	3.91%	$ 91,233.32	
4	Commercial Loan	Toronto Dominion Ba	Third-Party	Fixed Rate	14-Mar-12	24	$ 3,909,391	4.05%	$ 158,330.34	
5	Demand Loan	Toronto Dominion Ba	Third-Party	Variable Rate	1-Jan-12	Demand	$ 5,481,662	4.50%	$ 246,674.79	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 16,560,564	5.23%	$ 865,444.51	

Year 2013

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	
1	Bank Loan	Toronto Dominion Ba	Third-Party	Fixed Rate	29-Oct-10	20	$ 1,887,048	4.53%	$ 85,483.27	
2	Debentures	Town of Innsfil	Third-Party	Fixed Rate	1-Apr-95	20	$ 2,005,000	9.75%	$ 195,487.50	
3	Debentures	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	15	$ 2,166,667	3.91%	$ 84,716.68	
4	Commercial Loan	Toronto Dominion Ba	Third-Party	Fixed Rate	14-Mar-12	24	$ 3,805,466	4.05%	$ 154,121.37	
5	Demand	Toronto Dominion Ba	Third-Party	Variable Rate	1-Jan-12	Demand	$ 13,843,930	5.00%	$ 692,196.50	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 23,708,111	5.11%	$1,212,005.33	

Table 5.1.3 – Actual Weighted Average Cost of Long-Term Debt

Debt & Capital Cost Structure

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 Innisfil	Y	December 31, 2007	2,107,444	3	1.13%	2009	23,829
Denbentures	Town of Innsfil	N	April 1, 1995	5,032,000	20	9.75%	2009	490,620
Bank Loan	Toronto Dominion Bank	N	October 29, 2010	2,096,644	20	1.36%	2010	28,420
Denbentures	Town of Innsfil	N	April 1, 1995	4,382,000		9.75%	2010	427,245
Construction Loan	Infrastructure Ontario	N	April 15, 2010	2,500,000	Demand	1.45%	2010	36,250
Bank Loan	Toronto Dominion Bank	N	October 29, 2010	2,029,826		4.53%	2011	91,951
Denbentures	Town of Innsfil	N	April 1, 1995	3,666,000		9.75%	2011	357,435
Debentures	Infrastructure Ontario	N	August 15, 2011	2,500,000	15	3.91%	2011	97,750
Demand Loan	Toronto Dominion Bank	N	January 1, 2011	4,000,000		2.11%	2011	84,400
Bank Loan	Toronto Dominion Bank	N	October 29, 2010	1,960,178		4.53%	2012	88,796
Denbentures	Town of Innsfil	N	April 1, 1995	2,876,000		9.75%	2012	280,410
Debentures	Infrastructure Ontario	N	August 15, 2011	2,333,333		3.91%	2012	91,233
Commercial Loan	Toronto Dominion Bank	N	March 14, 2012	3,909,391	24	4.05%	2012	158,330
Demand Loan	Toronto Dominion Bank	N	January 1, 2012	5,481,662	Demand	4.50%	2012	246,675
Bank Loan	Toronto Dominion Bank	N	October 29, 2010	1,887,048		4.53%	2013	85,483
Denbentures	Town of Innsfil	N	April 1, 1995	2,005,000		9.75%	2013	195,488
Debentures	Infrastructure Ontario	N	August 15, 2011	2,166,667		3.91%	2013	84,717
Commercial Loan	Toronto Dominion Bank	N	March 14, 2012	3,805,466		4.05%	2013	154,121
Demand Loan	Toronto Dominion Bank	N	January 1, 2013	13,843,930	Demand	5.00%	2013	692,197
								0
								0

2009 Total Long Term Debt	7,139,444	**Total Interest Cost for 2009**	514,449
		Weighted Debt Cost Rate for 2009	7.21%
2010 Total Long Term Debt	8,978,644	**Total Interest Cost for 2010**	491,915
		Weighted Debt Cost Rate for 2010	5.48%
2011 Total Long Term Debt	12,195,826	**Total Interest Cost for 2011**	631,536
		Weighted Debt Cost Rate for 2011	5.18%
2012 Total Long Term Debt	16,560,564	**Total Interest Cost for 2012**	865,445
		Weighted Debt Cost Rate for 2012	5.23%
2013 Total Long Term Debt	23,708,111	**Total Interest Cost for 2013**	1,212,005
		Weighted Debt Cost Rate for 2013	5.11%

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

REVENUE DEFICIENCY - OVERVIEW:

Under Modified International Financial Reporting Standards (MIFRS), Innisfil's net revenue deficiency is $761,836 and when grossed up for PILs Innisfil's revenue deficiency is $787,625. This deficiency is calculated as the difference between the 2013 Test Year Revenue Requirement of $8,862,687 and the Forecast 2013 Test Year Revenue, based on the 2012 approved rates, at $8,100,851. Table 1.1 on the following page provides the revenue deficiency calculations.

Revenue Requirement:

Innisfil's Revenue Requirement consists of the following:

- Administrative & General, Billing & Collecting Expense
- Operation & Maintenance Expense
- Depreciation Expense
- Property Taxes
- PILS'
- Deemed Interest & Return on Equity

Innisfil's revenue requirement is primarily received through electricity distribution rates and offset by revenue from OEB-approved specific service charges, late payment charges, interest, and other operating income.

Table 6.1.1 Revenue Deficiency

Description	2012 Bridge Actual	2013 Test Existing Rates	2013 Test - Required Revenue
Revenue			
Revenue Deficiency			**761,836**
Distribution Revenue	8,503,677	8,100,851	8,100,851
Other Operating Revenue (Net)	422,748	556,948	556,948
Total Revenue	**8,926,425**	**8,657,799**	**9,419,635**
Costs and Expenses			
Administrative & General, Billing & Collecting	2,873,762	3,327,560	3,327,560
Operation & Maintenance	1,760,995	2,137,512	2,137,512
Depreciation & Amortization	1,422,426	1,611,954	1,611,954
Amortization PP&E Adjustment		-159,966	-159,966
Return on PP&E Adjustment		-42,167	-42,167
Property Taxes	12,000	12,500	12,500
Deemed Interest	945,411	1,119,814	1,119,814
Total Costs and Expenses	**7,014,594**	**8,007,207**	**8,007,207**
Utility Income Before Income Taxes	**1,911,831**	**650,592**	**1,412,428**
Income Taxes:			
Corporate Income Taxes	193,927	-92,296	25,788
Total Income Taxes	**193,927**	**-92,296**	**25,788**
Utility Net Income	**1,717,904**	**742,888**	**1,386,640**
Income Tax Expense Calculation:			
Accounting Income	1,911,831	650,592	1,412,428
Tax Adjustments to Accounting Income	-1,044,491	-1,246,052	-1,246,052
Taxable Income	**867,340**	**-595,460**	**166,376**
Income Tax Expense before credits	**193,927**	**-92,296**	**25,788**
Credits	**0**	**0**	**0**
Income Tax Expense	193,927	-92,296	25,788
Tax Rate Refecting Tax Credits	22.36%	15.50%	15.50%
Actual Return on Rate Base:			
Rate Base	31,728,141	38,010,954	38,010,954
Interest Expense	945,411	1,119,814	1,119,814
Net Income	1,717,904	742,888	1,386,640
Total Actual Return on Rate Base	**2,663,315**	**1,862,702**	**2,506,454**
Actual Return on Rate Base	8.39%	4.90%	6.59%
Required Return on Rate Base:			
Rate Base	31,728,141	38,010,954	38,010,954
Return Rates:			
Return on Debt (Weighted)	4.97%	4.91%	4.91%
Return on Equity	8.01%	9.12%	9.12%
Deemed Interest Expense	945,411	1,119,814	1,119,814
Return On Equity	1,016,570	1,386,640	1,386,640
Total Return	**1,961,981**	**2,506,454**	**2,506,454**
Expected Return on Rate Base	6.18%	6.59%	6.59%
Revenue Deficiency After Tax	**-701,334**	**643,752**	**-0**
Revenue Deficiency Before Tax	**-903,302**	**761,836**	**-0**

COST DRIVERS ON REVENUE DEFICIENCY

The Applicant notes there are several factors that contribute to the gross revenue deficiency of $761,836 for the 2013 Test Year. The following discussion highlights some significant items that contribute to this deficiency.

Operating Expenses

Innisfil's OM&A expenses have increased from the 2009 approved amount of $3,897,740 to $5,465,072 in the 2013 Test Year. The increased costs are mainly due to the hiring/retaining of staff, asset management plan maintenance and software maintenance. Details of the cost drivers are outlined in Exhibit 4, Tab 1.

Rate Base

In this application Innisfil is applying for a rate base of $38,010,954 compared to a rate base of $22,869,990 which was approved during Innisfil's 2009 cost of service application. The working capital allowance has increased by $400k from the 2009 Board Approved amount due to increases in the cost of power and increases in the applicant's operating expenses. The most significant increase however is the increase in the net book value of fixed assets which has risen by $14.7 million since the 2009 Board Approved amount. This increase has been primarily driven by the installation of smart meters, capital improvements required to accommodate customer demand and to replace aging assets and a new operations and administration building. The changes due to MIFRS, working capital and capital spending have been fully disclosed in Exhibit 2 of this application.

These changes have resulted in increased deemed interest expense of $229,722. Also the increased rate base, plus the increase in deemed return on equity from 8.01% to 9.12% has caused deemed return on equity to increase by $593,432.

Exhibit	Schedule	Appendix	Contents
7 – Cost Allocation	1		Cost Allocation Overview
	2		Summary of Results and Proposed Changes
	3		Cost Allocation Summary
		A	Cost Allocation Study

COST ALLOCATION OVERVIEW:

Introduction:

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 Distribution Systems Limited ("IHDSL") prepared a cost allocation information filing consistent with IHDSL's understanding of the Directions, the Guidelines, the Model and the Instructions. IHDSL submitted this filing to the OEB on January 22, 2007.

One of the main objectives of the filing was to provide information on any apparent cross-subsidization among a distributor's rate classifications. It was felt that this would give an indication of cross-subsidization from one class to another and this information would be useful as a tool in future rate applications.

In IHDSL's 2009 EDR COS Application (EB-2008-0233), the results of the original cost allocation study filed on January 22, 2007 was used as a b asis for IHDSL to propose reallocations of distribution costs across customer classes to address the issue of cross-subsidization. The reallocations were based on the objective of moving the revenue to cost ratios to be within the Board's acceptable range as outlined in the "Report on A pplication of Cost Allocation for Electricity Distributors" (the Cost Allocation Report") issued by the OEB on November 28, 2007.

On September 2, 2010, the Board began a proceeding, EB-2010-0219, with the mandate to review and revise the existing Cost Allocation policy as needed. On March 31, 2011, the Report of the Board was released in relation to EB-2010-0219. In the letter accompanying the report, the Board indicated that a Working Group would be formed to revise the original Cost Allocation Model to address the revision highlighted in the March 31st Board Report. On August 5, 2011, the Board released the new Cost Allocation model and instructed 2012 Cost of Service filers to use the revised model in their applications. In the March 31st Board Report, the Board

stated that "default weighting factors should now be utilized only in exceptional circumstances". Distributors are therefore now expected to develop their own weighting factors.

For the purposes of this Application, IHDSL has submitted the revised cost allocation study to reflect 2013 test year costs, customer numbers and demand values. The 2013 demand values are based on the weather normalized load forecast used to design rates. IHDSL has utilized the following weighting factors for utilization within this application.

Services (Account 1855)

Rate Class	Services Weighting Factor
Residential	1
General Service < 50kW	1.5
General Service ≥ 50 kW	2
Street Light	0
Sentinel Light	0
Unmetered Scattered Load	0

IHDSL has used LDC specific factors versus the use of default factors used on the Informational Filing. IHDSL has applied service and billing & collecting weightings for each customer classification. These weightings are based upon costs incurred servicing these particular customer classifications and were weighted as a result of discussions with experienced LDC colleagues. For example:

- Residential: weighted for services and for billing and collecting as "1 " per Cost Allocation instruction sheet
- General Service less than 50 kW: Weighting for services is "1.5" as the cost of installation usually requires after hours attendances to mitigate against interruptions during normal business hours. Additional time is also required to ensure the demand data is programmed and monitored appropriately.
- General Service greater than 50 kW: Weighting for services is "2" as the cost of installation usually requires after hours attendances to mitigate against interruptions during normal business hours. Additional time is also required to ensure the demand data is programmed and monitored appropriately. These installations require additional planning and preparation time due to the complexity of the metering equipment.

Billing and Collection (Accounts 5315 – 5340, except 5335)

Rate Class	Billing Weighting Factor
Residential	1
General Service < 50kW	.10
General Service ≥ 50 kW	.06
Street Light (per connection)	0
Sentinel Light	0.01
Unmetered Scattered Load	0

IHDSL is comfortable that the weightings utilized provide a reasonable result of the allocation of the costs to the customer classes. The analysis utilized to arrive at the Billing and Collecting weightings is provided below,

Rate Class	Residential	GS<50	GS>50	Street Lights	Sentinal Lights	USL	Total	
# Customers	14,176	907	66	5	238	10	15,402	
# Connections				2,880	238	77		
5315 - customer billing *	92.04%	5.89%	0.43%	0.03%	1.54%	0.06%	100.00%	$480,600.00
5320 - collecting**	1	0.15	0.15	0	0	0	1.3	$340,820.00
% of 5315	$442,351.90	$ 28,313.16	$ 2,053.40	$ 156.02	$ 7,413.47	$ 312.04	$480,600.00	
%of 5320	$262,169.23	$ 39,325.38	$ 39,325.38	$ -	$ -	$ -	$340,820.00	
Revised Tot of 5315 & 5320	$704,521.13	$ 67,638.54	$ 41,378.78	$ 156.02	$ 7,413.47	$ 312.04	$821,420.00	
	85.77%	8.23%	5.04%	0.02%	0.90%	0.04%	100.00%	
Weigt Factor	1.00	0.10	0.06	0.00	0.01	0.00	1.17	

*** based on relative time to bill one customer per class**

**** based on the time to collect per customer per class, more weight to resifential due to changes to low income, deposits, etc**

Meter Capital (Sheet I7.1)

Customer Class	Weighted Average Cost
Residential	$99.35
GS >50	$244.72
GS <50-4,999	$669.98

Meter Reading (Sheet I7.2)

Meter Type	Meter Reading Weighting Factor
Smart/Interval Meter	1

SUMMARY OF RESULTS AND PROPOSED CHANGES:

The data used in the updated cost allocation study is consistent with IHDSL's cost data that supports the proposed 2013 revenue requirement outlined in this application. Consistent with the Guidelines, IHDSL's assets were broken out into primary and secondary distribution functions using breakout percentages consistent with the original cost allocation informational filing. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to IHDSL, its engineering records, and its customer and financial information systems. The cost allocation study has been included in Appendix A.

Capital contributions, depreciation and accumulated depreciation by USoA are consistent with the information provided in the 2013 continuity statement shown in Exhibit 2. The rate class customer data used in the updated cost allocation study is consistent with the 2013 customer forecast outlined in Exhibit 3. The load profiles for all other rate classes are the same as those used in the original information filing, but have been scaled to match the load forecast.

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. T he 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 tables, Output O1 Cost Allocation Model, and Appendix 2-P reflect IHDSL's revenue cost ratios, as a result of the updated 2013 cost allocation study.

Output O1 – Cost Allocation Model

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residental	2 GS < 50	3 GS 50-4,999 kW	7 Street Light	8 Sentinel Light	9 Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$8,100,851	$6,344,682	$654,387	$673,571	$351,024	$31,826	$45,361
mi	Miscellaneous Revenue (mi)	$556,948	$471,496	$30,811	$13,010	$37,388	$2,658	$1,584
		Miscellaneous Revenue Input equals Output						
	Total Revenue at Existing Rates	$8,657,799	$6,816,178	$685,197	$686,581	$388,413	$34,485	$46,944
	Factor required to recover deficiency (1 + D)	1.0940						
	Distribution Revenue at Status Quo Rates	$8,862,687	$6,941,361	$715,928	$736,916	$384,036	$34,819	$49,626
	Miscellaneous Revenue (mi)	$556,948	$471,496	$30,811	$13,010	$37,388	$2,658	$1,584
	Total Revenue at Status Quo Rates	$9,419,635	$7,412,857	$746,739	$749,927	$421,425	$37,478	$51,210
	Expenses							
di	Distribution Costs (di)	$1,689,663	$1,309,961	$101,007	$98,993	$162,611	$11,802	$5,289
cu	Customer Related Costs (cu)	$1,553,869	$1,454,175	$64,782	$23,700	$9,941	$1,004	$267
ad	General and Administration (ad)	$2,234,040	$1,898,612	$115,238	$86,028	$121,250	$9,000	$3,912
dep	Depreciation and Amortization (dep)	$1,451,988	$1,133,671	$101,095	$84,833	$119,432	$8,988	$3,969
INPUT	PILs (INPUT)	$25,788	$20,180	$1,726	$1,543	$2,110	$158	$72
INT	Interest	$1,119,814	$876,278	$74,955	$66,983	$91,606	$6,882	$3,110
	Total Expenses	$8,075,162	$6,692,877	$458,802	$362,081	$506,949	$37,834	$16,619
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$1,344,473	$1,052,078	$89,992	$80,421	$109,984	$8,263	$3,734
	Revenue Requirement (includes NI)	$9,419,635	$7,744,955	$548,794	$442,503	$616,933	$46,097	$20,354
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$62,338,172	$48,479,080	$4,048,901	$3,783,045	$5,437,120	$408,323	$181,702
gp	General Plant - Gross	$11,119,283	$8,683,510	$722,740	$646,763	$962,563	$71,642	$32,065
accum dep	Accumulated Depreciation	($30,319,373)	($23,485,468)	($1,982,267)	($1,933,730)	($2,629,508)	($199,825)	($88,576)
co	Capital Contribution	($8,990,162)	($6,967,735)	($518,486)	($466,092)	($940,317)	($68,002)	($29,529)
	Total Net Plant	$34,147,920	$26,709,388	$2,270,888	$2,029,986	$2,829,858	$212,138	$95,661
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$24,238,088	$15,370,429	$3,296,927	$5,339,811	$157,890	$10,924	$62,108
	OM&A Expenses	$5,477,572	$4,662,748	$281,026	$208,722	$293,802	$21,806	$9,468
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$29,715,660*	*$20,033,177*	*$3,577,953*	*$5,548,533*	*$451,693*	*$32,729*	*$71,575*
	Working Capital	$3,863,036	$2,604,313	$465,134	$721,309	$58,720	$4,255	$9,305
	Total Rate Base	$38,010,956	$29,313,701	$2,736,022	$2,751,296	$2,888,578	$216,393	$104,966
		Rate Base Input equals Output						
	Equity Component of Rate Base	$15,204,382	$11,725,480	$1,094,409	$1,100,518	$1,155,431	$86,557	$41,986
	Net Income on Allocated Assets	$1,344,473	$719,980	$287,937	$387,846	($85,525)	($356)	$34,591
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$1,344,473	$719,980	$287,937	$387,846	($85,525)	($356)	$34,591
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES STATUS QUO%	100.00%	95.71%	136.07%	169.47%	68.31%	81.30%	251.60%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($761,836)	($928,777)	$136,404	$244,079	($228,520)	($11,612)	$26,591
		Deficiency Input equals Output						
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($332,098)	$197,945	$307,424	($195,509)	($8,619)	$30,857
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.84%	6.14%	26.31%	35.24%	-7.40%	-0.41%	82.39%

Appendix 2-P Cost Allocation

a) Allocated Costs

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 6,458,734	78.37%	$ 7,902,557	83.89%
GS < 50 kW	$ 600,098	7.28%	$ 550,328	5.84%
GS > 50 kW-4,999 kW	$ 524,422	6.36%	$ 442,688	4.70%
Street Lighting	$ 539,062	6.54%	$ 464,773	4.93%
Sentinel Lighting	$ 43,872	0.53%	$ 41,367	0.44%
Unmetered Scattered Load (USL)	$ 75,503	0.92%	$ 17,922	0.19%
Embedded distributor class		0.00%		0.00%
Total	$ 8,241,691	100.00%	$ 9,419,635	100.00%

b) Calculated Class Revenues

Classes (same as previous table)	Column 7B Load Forecast (LF) X current	Column 7C L.F. X current approved rates	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 6,344,682	$ 6,941,361	$ 7,234,973	$ 477,568
GS < 50 kW	$ 654,387	$ 715,928	$ 629,481	$ 30,913
GS > 50 kW-4,999 kW	$ 673,571	$ 736,916	$ 518,208	$ 13,018
Street Lighting	$ 351,024	$ 384,036	$ 422,247	$ 31,350
Sentinel Lighting	$ 31,826	$ 34,819	$ 37,807	$ 2,565
Unmetered Scattered Load (USL)	$ 45,361	$ 49,626	$ 19,972	$ 1,534
Embedded distributor class				
Total	$ 8,100,851	$ 8,862,687	$ 8,862,688	$ 556,948

IHDSL is proposing in this application to re-align its revenue to cost ratios by adjusting the allocations of revenue among rate classes in order to reduce some of the cross-subsidization that is occurring and to continue to move towards a cost ratio of 100% for all rate classes.

Class	Revenue Requirement - 2013 Cost Allocation Model - Line 40 from O1 in CA	2013 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2013 Cost Allocation Model - Line 19 from O1 in CA	Total Revenue	Revenue Cost Ratio	Check Revenue Cost Ratios from 2013 Cost Allocation Model - Line 75 from O1 in CA	Proposed Revenue to Cost Ratio	Proposed Revenue	Miscellaneous Revenue	Proposed Base Revenue
Residential	7,902,557	6,941,361	477,568	7,418,929	93.9%	93.9%	97.59551%	7,712,541	477,568	7,234,973
GS < 50 kW	550,328	715,928	30,913	746,841	135.7%	135.7%	120.00%	660,394	30,913	629,481
GS >50 to 4999 kW	442,688	736,916	13,018	749,934	169.4%	169.4%	120.00%	531,226	13,018	518,208
Sentinel Lights	41,367	34,819	2,565	37,385	90.4%	90.4%	97.59551%	40,372	2,565	37,807
Street Lighting	464,773	384,036	31,350	415,386	89.4%	89.4%	97.59551%	453,597	31,350	422,247
Unmetered and Scattered	17,922	49,626	1,534	51,160	285.5%	285.5%	120.00%	21,506	1,534	19,972
TOTAL	9,419,635	8,862,687	556,948	9,419,635				9,419,636	556,948	8,862,688

The proposed re-alignment will move the following rate classes to balance the 2013 Base Revenue Requirement;

- Increase Residential to 97.60% from 93.88%
- Decrease GS<50 kW to 120.0% from 135.71%
- Decrease GS>50 – 4,999 kW to 120% from 169.4%
- Increase Sentinel Lighting to 97.60% from 90.4%
- Increase Street Lighting to 97.60% from 89.4%
- Decrease Unmetered Scattered to 120% from 285.5%

The aforementioned alignments will achieve the following cost ratios for IHDSL's rate classes which are at or within the Board's cost ratio policy ranges.

Class	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
	Most Recent Year: May,1,2009	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	%	%	%	%
Residential	101.20	93.88	97.60%	85 - 115
GS < 50 kW	116.20	135.71	120.00%	80 - 120
GS > 50 kW-4,999 kW	135.80	169.40	120.00%	80 - 120
Street Lighting	70.00	89.37	97.60%	70 - 120
Sentinel Lighting	70.00	90.37	97.60%	80 - 120
Unmetered Scattered Load (USL)	80.00	285.47	120.00%	80 - 120

COST ALLOCATION SUMMARY

IHDSL respectfully submits that the proposed reallocation of distribution revenue is fair and reasonable and customer class revenues will continue to move towards the 100% cost revenue by rate class.

Appendix A

2013 Updated Cost Allocation Study

Sheet I6.1 Revenue Worksheet - Final Run September 10, 2012

Total kWhs from Load Forecast	231,119,409
Total kWs from Load Forecast	151,169
Deficiency from RRWF	- 761,836
Miscellaneous Revenue	556,948

			1	2	3	7	8	9
	ID	Total	Residental	GS < 50	GS 50-4,999 kW	Street Light	Sentinel Light	Unmetered Scattered Load
Billing Data								
Forecast kWh	CEN	231,119,409	146,562,898	31,437,455	50,917,130	1,505,545	104,161	592,220
Forecast kW	CDEM	151,169			146,480	4,400	289	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		27,858			27,858			
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-						
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	231,119,409	146,562,898	31,437,455	50,917,130	1,505,545	104,161	592,220
kWh - 30 year weather normalized amount	Click here to Enter Data	-	-	-	-	-	-	-
Existing Monthly Charge			$21.08	$35.18	$320.64	$5.39	$7.64	$23.51
Existing Distribution kWh Rate			$0.0188	$0.0086				$0.0396
Existing Distribution kW Rate					$2.9751	$37.3061	$34.7951	
Existing TFOA Rate			$0.60	$0.60	$0.60	$0.60	$0.60	$0.60
Additional Charges								
Distribution Revenue from Rates		$8,117,566	$6,344,682	$654,387	$690,286	$351,024	$31,826	$45,361
Transformer Ownership Allowance		$16,715	$0	$0	$16,715	$0	$0	$0
Net Class Revenue	CREV	$8,100,851	$6,344,682	$654,387	$673,571	$351,024	$31,826	$45,361
Data Mismatch Analysis								
Revenue with 30 year weather normalized kWh		-	-	-	-	-	-	-

Weather Normalized Data from Hydro One	Total	Residental	GS < 50	GS 50-4,999 kW	Street Light	Sentinel Light	Unmetered Scattered Load
kWh - 30 year weather normalized amount	-						
Loss Factor							

Sheet I6.2 Customer Data Worksheet - Final Run September 10, 2012

			1	2	3	7	8	9
	ID	Total	Residental	GS < 50	GS 50-4,999 kW	Street Light	Sentinel Light	Unmetered Scattered Load
Billing Data								
Bad Debt 3 Year Historical Average	BDHA	$68,551	$58,288	$1,580	$8,683	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$113,905	$96,952	$12,734	$3,673	$0	$114	$432
Number of Bills	CNB	185,008	170,270.37	10,915.99	793.71	60.00	2,847.88	120.00
Number of Devices						2,889		78
Number of Connections (Unmetered)	CCON	2,628				2,550		78
Total Number of Customers	CCA	15,417	14,189	910	66	5	237	10
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	15,417	14,189	910	66	5	237	10
Line Transformer Customer Base	CCLT	15,413	14,189	910	62	5	237	10
Secondary Customer Base	CCS	13,904	13,507	228	-	3	158	8
Weighted - Services	CWCS	13,849	13,507	342	-	-	-	-
Weighted Meter -Capital	CWMC	1,665,629	1,398,596	221,474	45,559	-	-	-
Weighted Meter Reading	CWMR	15,099	14,176	907	9	0	7	-
Weighted Bills	CWNB	171,395	170,270	1,048	47	0	30	0

Bad Debt Data

Historic Year:	2010	56,315	50,887	321	5,107			
Historic Year:	2011	72,753	66,443	1,711	4,599			
Historic Year:	2012	76,586	57,535	2,707	16,344			
Three-year average		**68,551**	**58,288**	**1,580**	**8,683**	**-**	**-**	**-**

Total Number of Customer from 2006 Cost Allocation	CCA	13,689	12,670	771	74	5	159	10
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	13,689	12,670	771	74	5	159	10
Line Transformer Customer Base	CCLT	13,684	12,670	771	69	5	159	10
% to Total customers			100%	100%	93%	100%	100%	100%
Secondary Customer Base	CCS	12,371	12,061	193	-	3	106	8
% to Total customers			95%	25%	0%	60%	67%	80%

Sheet I8 Demand Data Worksheet - Final Run September 10, 2012

This is an input sheet for demand allocators.

CP TEST RESULTS	4 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residental	2 GS < 50	3 GS 50-4,999 kW	7 Street Light	8 Sentinel Light	9 Unmetered Scattered Load
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	49,474	40,614	3,359	5,053	327	33	88
Bulk Delivery CP	BCP1	49,474	40,614	3,359	5,053	327	33	88
Total Sytem CP	DCP1	49,474	40,614	3,359	5,053	327	33	88
4 CP								
Transformation CP	TCP4	190,329	152,081	14,772	21,676	1,312	131	357
Bulk Delivery CP	BCP4	190,329	152,081	14,772	21,676	1,312	131	357
Total Sytem CP	DCP4	190,329	152,081	14,772	21,676	1,312	131	357
12 CP								
Transformation CP	TCP12	480,144	366,099	43,931	66,891	1,967	196	1,060
Bulk Delivery CP	BCP12	480,144	366,099	43,931	66,891	1,967	196	1,060
Total Sytem CP	DCP12	480,144	366,099	43,931	66,891	1,967	196	1,060
NON CO_INCIDENT PEAK								
1 NCP								
Classification NCP from Load Data Provider	DNCP1	53,456	40,614	4,947	7,438	332	33	92
Primary NCP	PNCP1	53,456	40,614	4,947	7,438	332	33	92
Line Transformer NCP	LTNCP1	53,456	40,614	4,947	7,438	332	33	92
Secondary NCP	SNCP1	40,196	38,665	1,237		199	22	74
4 NCP								
Classification NCP from Load Data Provider	DNCP4	201,924	153,921	18,174	28,009	1,327	131	362
Primary NCP	PNCP4	201,924	153,921	18,174	28,009	1,327	131	362
Line Transformer NCP	LTNCP4	201,924	153,921	18,174	28,009	1,327	131	362
Secondary NCP	SNCP4	152,249	146,533	4,544		796	87	290
12 NCP								
Classification NCP from Load Data Provider	DNCP12	504,538	370,216	49,384	79,538	3,948	392	1,060
Primary NCP	PNCP12	504,538	370,216	49,384	79,538	3,948	392	1,060
Line Transformer NCP	LTNCP12	504,538	370,216	49,384	79,538	3,948	392	1,060
Secondary NCP	SNCP12	368,270	352,446	12,346		2,369	261	848

Sheet O1 Revenue to Cost Summary Worksheet - Final Run September 10, 2012

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residental	2 GS < 50	3 GS 50-4,999 kW	7 Street Light	8 Sentinel Light	9 Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$8,100,851	$6,344,682	$654,387	$673,571	$351,024	$31,826	$45,361
mi	Miscellaneous Revenue (mi)	$556,948	$477,568	$30,913	$13,018	$31,350	$2,565	$1,534
		Miscellaneous Revenue Input equals Output						
	Total Revenue at Existing Rates	$8,657,799	$6,822,250	$685,300	$686,589	$382,374	$34,391	$46,894
	Factor required to recover deficiency (1 + D)	1.0940						
	Distribution Revenue at Status Quo Rates	$8,862,687	$6,941,361	$715,928	$736,916	$384,036	$34,819	$49,626
	Miscellaneous Revenue (mi)	$556,948	$477,568	$30,913	$13,018	$31,350	$2,565	$1,534
	Total Revenue at Status Quo Rates	$9,419,635	$7,418,929	$746,841	$749,934	$415,386	$37,385	$51,160
	Expenses							
di	Distribution Costs (di)	$1,689,663	$1,362,636	$101,223	$99,038	$112,491	$9,931	$4,343
cu	Customer Related Costs (cu)	$1,553,869	$1,455,093	$64,840	$23,705	$8,939	$1,019	$273
ad	General and Administration (ad)	$2,234,040	$1,935,752	$115,439	$86,063	$85,795	$7,726	$3,265
dep	Depreciation and Amortization (dep)	$1,451,988	$1,161,487	$101,447	$84,871	$92,387	$8,224	$3,572
INPUT	PILs (INPUT)	$25,788	$20,584	$1,733	$1,543	$1,710	$150	$67
INT	Interest	$1,119,814	$893,840	$75,272	$67,012	$74,275	$6,506	$2,909
	Total Expenses	$8,075,162	$6,829,393	$459,955	$362,232	$375,597	$33,555	$14,429
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$1,344,473	$1,073,164	$90,373	$80,456	$89,176	$7,812	$3,492
	Revenue Requirement (includes NI)	$9,419,635	$7,902,557	$550,328	$442,688	$464,773	$41,367	$17,922
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$62,338,172	$49,715,995	$4,065,175	$3,784,749	$4,232,670	$375,170	$164,413
gp	General Plant - Gross	$11,119,283	$8,910,223	$725,412	$647,056	$742,468	$65,330	$28,793
accum dep	Accumulated Depreciation	($30,319,373)	($24,032,683)	($1,991,196)	($1,934,588)	($2,092,627)	($186,673)	($81,607)
co	Capital Contribution	($8,990,162)	($7,312,622)	($519,160)	($466,347)	($614,151)	($54,924)	($22,958)
	Total Net Plant	$34,147,920	$27,280,913	$2,280,232	$2,030,870	$2,268,360	$198,904	$88,641
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$24,238,088	$15,370,429	$3,296,927	$5,339,811	$157,890	$10,924	$62,108
	OM&A Expenses	$5,477,572	$4,753,481	$281,503	$208,806	$207,225	$18,676	$7,881
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$29,715,660***	***$20,123,910***	***$3,578,430***	***$5,548,617***	***$365,115***	***$29,599***	***$69,989***
	Working Capital	$3,863,036	$2,616,108	$465,196	$721,320	$47,465	$3,848	$9,099
	Total Rate Base	$38,010,956	$29,897,021	$2,745,428	$2,752,190	$2,315,825	$202,751	$97,740
		Rate Base Input equals Output						
	Equity Component of Rate Base	$15,204,382	$11,958,808	$1,098,171	$1,100,876	$926,330	$81,101	$39,096
	Net Income on Allocated Assets	$1,344,473	$589,536	$286,886	$387,702	$39,789	$3,829	$36,731
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$1,344,473	$589,536	$286,886	$387,702	$39,789	$3,829	$36,731
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES STATUS QUO%	100.00%	93.88%	135.71%	169.40%	89.37%	90.37%	285.47%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($761,836)	($1,080,307)	$134,972	$243,900	($82,398)	($6,976)	$28,972
		Deficiency Input equals Output						
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($483,628)	$196,513	$307,246	($49,387)	($3,982)	$33,238
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.84%	4.93%	26.12%	35.22%	4.30%	4.72%	93.95%

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Final Run September 10, 2012

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	8	9
	Residental	GS < 50	GS 50-4,999 kW	Street Light	Sentinel Light	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$7.98	$7.85	$18.76	$0.29	$0.31	-$0.17
Customer Unit Cost per month - Directly Related	$13.31	$12.71	$31.14	$0.50	$0.56	$0.04
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$31.47	$25.18	$58.35	$15.15	$14.45	$12.93
Existing Approved Fixed Charge	$21.08	$35.18	$320.64	$5.39	$7.64	$23.51

Information to be Used to Allocate PILs, ROD, ROE and A&G

	Total	1 Residental	2 GS < 50	3 GS 50-4,999 kW	7 Street Light	8 Sentinel Light	9 Unmetered Scattered Load
General Plant - Gross Assets	$11,119,283	$8,910,223	$725,412	$647,056	$742,468	$65,330	$28,793
General Plant - Accumulated Depreciation	($3,475,200)	($2,784,784)	($226,719)	($202,230)	($232,050)	($20,418)	($8,999)
General Plant - Net Fixed Assets	$7,644,083	$6,125,439	$498,693	$444,826	$510,419	$44,912	$19,794
General Plant - Depreciation	$525,195	$420,855	$34,263	$30,562	$35,069	$3,086	$1,360
Total Net Fixed Assets Excluding General Plant	$26,503,837	$21,155,474	$1,781,539	$1,586,044	$1,757,942	$153,991	$68,847
Total Administration and General Expense	$2,234,040	$1,935,752	$115,439	$86,063	$85,795	$7,726	$3,265
Total O&M	$3,243,532	$2,817,730	$166,063	$122,743	$121,430	$10,950	$4,616

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residental	2 GS < 50	3 GS 50-4,999 kW	7 Street Light	8 Sentinel Light	9 Unmetered Scattered Load
	Distribution Plant							
1860	Meters	$2,581,864	$2,167,941	$343,303	$70,620	$0	$0	$0
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant - Meters only	($638,857)	($536,436)	($84,947)	($17,474)	$0	$0	$0
	Meter Net Fixed Assets	**$1,943,007**	**$1,631,505**	**$258,356**	**$53,146**	**$0**	**$0**	**$0**
	Misc Revenue							
4082	Retail Services Revenues	$0	$0	$0	$0	$0	$0	$0
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($113,700)	($96,778)	($12,712)	($3,666)	$0	($113)	($431)
	Sub-total	*($113,700)*	*($96,778)*	*($12,712)*	*($3,666)*	*$0*	*($113)*	*($431)*
	Operation							
5065	Meter Expense	$339,849	$285,365	$45,189	$9,296	$0	$0	$0
5070	Customer Premises - Operation Labour	$48,400	$38,090	$2,442	$178	$6,845	$637	$208
5075	Customer Premises - Materials and Expenses	$14,800	$11,647	$747	$54	$2,093	$195	$64
	Sub-total	*$403,049*	*$335,102*	*$48,377*	*$9,528*	*$8,938*	*$832*	*$272*
	Maintenance							
5175	Maintenance of Meters	$44,800	$37,618	$5,957	$1,225	$0	$0	$0
	Billing and Collection							
5310	Meter Reading Expense	$38,000	$35,677	$2,283	$22	$0	$18	$0
5315	Customer Billing	$480,600	$477,446	$2,939	$131	$0	$84	$0
5320	Collecting	$340,820	$338,584	$2,084	$93	$0	$60	$0
5325	Collecting- Cash Over and Short	$100	$99	$1	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0
	Sub-total	$859,520	$851,807	$7,306	$245	$0	$162	$0
	Total Operation, Maintenance and Billing	$1,307,369	$1,224,526	$61,640	$10,998	$8,939	$993	$272
	Amortization Expense - Meters	$133,656	$112,228	$17,772	$3,656	$0	$0	$0
	Allocated PILs	$1,468	$1,231	$196	$40	$0	$0	$0
	Allocated Debt Return	$63,737	$53,455	$8,528	$1,754	$0	$0	$0
	Allocated Equity Return	$76,524	$64,179	$10,239	$2,105	$0	$0	$0
	Total	**$1,469,054**	**$1,358,842**	**$85,665**	**$14,887**	**$8,939**	**$880**	**($159)**

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Exhibit	Tab	Schedule	Appendix	Contents
8 – Rate Design				
	1	1		Rate Design Overview
	2	1		Fixed/Variable Proportion
	3	1		Low Voltage Charges
	4	1		Retail Transmission Service Rates
	5	1		Loss Adjustment Factors
	6	1		Rate Mitigation
	7	1		Specific Service Charges
	8	1		Existing and Proposed Rate Classes
	8	2		Existing Rate Schedule
	8	3		GEA Funding Adder
	8	4		Proposed Rate Schedule
	9	1		Reconciliation of Rate Class Revenue
	10	1		Rate and Bill Impacts
			A	Existing Rates
			B	Proposed Rates
			C	Bill Impacts by Rate Class

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RATE DESIGN OVERVIEW:

This Exhibit documents the calculation of IHDSL's proposed distribution rates by rate class for the 2013 test year, based on the rate design as proposed in this Exhibit.

IHDSL has determined its total 2013 service revenue requirement to be $9,419,635. The total revenue offsets in the amount of $556,948 reduce IHDSL's total service revenue requirement to a base revenue requirement to $8,862,687 which is used to determine the proposed distribution rates. T he base revenue requirement is derived from IHDSL's 2013 capital and operating forecasts, weather normalized usage, forecasted customer counts, and regulated return on rate base. The revenue requirement is summarized in the table below:

Table 8.1 Calculation of Base Revenue

Rate Classification	Revenue Requirement	
OM&A Expenses	$	5,465,072
Amortization Expenses	$	1,451,988
Regulated Return On Capital	$	2,506,454
PILS	$	38,288
Transition frm CGAAP to MIFRS	-$	42,167
Service Revenue Requirement	$	9,419,635
Less: Reveune Offsets	$	556,948
Base Revenue Requirement	$	8,862,687

Allocation of Base Revenue Requirements:

The outstanding base revenue requirement is allocated to the various rate classes using the proposed revenue to cost ratios outlined in Exhibit 7 – Cost Allocation. The following tables

shows how the base revenue requirement has been allocated to the rate classes and the associated fixed and variable allocations..

Table 8.1A - Allocation of Base Revenue Requirment to Rate Classes

Rate Classification	Total Net Rev Requirement	Total Fixed Revenue	Total Variable Revenue	Fixed Revenue Proportion	Variable Revenue Proportion	Total
Residential	7,234,973	4,092,953	3,142,020	56.57%	43.43%	100.0%
GS<50kW	629,481	369,409	260,072	58.68%	41.32%	100.0%
GS>50kW-4,999 kW	518,208	195,793	322,415	37.78%	62.22%	100.0%
Sentinel Lights	37,807	25,847	11,961	68.36%	31.64%	100.0%
Street Lights	422,247	224,788	197,460	53.24%	46.76%	100.0%
Unmetered Scattered Load	19,972	9,646	10,326	48.30%	51.70%	100.0%
Total	**8,862,688**	**4,918,436**	**3,944,253**	**55.50%**	**44.50%**	**100.0%**
Total Forecast Fixed/Variable Rates				**55.50%**	**44.50%**	**100.0%**

Table 8.2 Rate Class Base Revenue Requirement

Rate Classification	2012 Base Revenue	
Residential	$	7,234,973
GS<50kW	$	629,481
GS>50kW-4,999 kW	$	518,208
Sentinel Lights	$	37,807
Street Lights	$	422,247
Unmetered Scattered Load	$	19,972
Total	$	8,862,688

Determination of Monthly Fixed Charges:

Based on applying the existing approved monthly service charges, excluding the smart meter adder, to the forecasted number of customers for 2013 and applying the existing approved distribution volumetric charge, excluding the adjustment for LV and transformation allowance to 2013 forecasted volumes, the following table outlines IHDSL's current split between fixed and variable distribution revenue.

Table 8.3 Current Fixed Variable Split

Rate Classification	Total Net Rev Requirement	Total Fixed Revenue	Total Variable Revenue	Fixed Revenue Proportion	Variable Revenue Proportion	Total
Residential	7,234,973	4,092,953	3,142,020	56.57%	43.43%	100.0%
GS<50kW	629,481	369,409	260,072	58.68%	41.32%	100.0%
GS>50kW-4,999 kW	518,208	195,793	322,415	37.78%	62.22%	100.0%
Sentinel Lights	37,807	25,847	11,961	68.36%	31.64%	100.0%
Street Lights	422,247	224,788	197,460	53.24%	46.76%	100.0%
Unmetered Scattered Load	19,972	9,646	10,326	48.30%	51.70%	100.0%
Total	**8,862,688**	**4,918,436**	**3,944,253**	**55.50%**	**44.50%**	**100.0%**
Total Forecast Fixed/Variable Rates				**55.50%**	**44.50%**	**100.0%**

IHDSL submits that it is appropriate for 2013 to maintain the same fixed/variable proportions assumed in the current rates to all customer classifications.

In its November 28, 2007 Report on Application of Cost Allocation for Electricity Distributors, the OEB addressed a number of "Other Rate Matters", including the treatment of the fixed rate component (the Monthly Service Charge, or 'MSC') of the bill. 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". IHDSL's MSCs exceed that floor amount by rate class. With respect to the upper bound for the MSC, the OEB considered it to be inappropriate to make changes to the MSC ceiling at this time, given the number of issues that remain to be examined within the scope of the OEB's Rate Review proceeding (EB-2009-0031). The OEB indicated that for the time being it does not expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the

MSC; and, that distributors that are currently above that value are not required to make changes to their current MSC to bring it to or below that level at this time. In accordance with the filing requirements, the following information has been provided with regards to the MSC.

Table 8.4 Monthly Service Charge (MSC) from Cost Allocation Model

Rate Classification	2012 Approved MSC	Customer Unit Cost- Avoided Cost	Customer Unit Cost - Minimum System PLCC Adjustment
Residential	$ 21.08	$ 7.98	$ 31.47
GS<50kW	$ 35.18	$ 7.85	$ 25.1839
GS>50kW-4,999 kW	$ 320.64	$ 18.76	$ 58.3542
Sentinel Lights	$ 7.64	$ 0.31	$ 14.4479
Street Lights	$ 5.39	$ 0.29	$ 15.1532
Unmetered Scattered Load	$ 23.51	$ 0.17	$ 12.9329

Consistent with recent Board Decision on 2011 cost of service rate applications for Hydro One Brampton, Kenora Hydro and Horizon Utilities this Application proposes to maintain the current fixed/variable proportions for all rate classes as shown in the following table

Table 8.5 Proposed Monthly Service Charge

Rate Classification		Base Revenue Requirement	Fixed Revenue Proportion	Fixed Revenue	Annualized Customers/ Connections		Proposed Fixed Charge
Residential	$	7,234,973	56.57%	4,092,953	170,270	$	24.04
GS<50kW	$	629,481	58.68%	369,409	10,916	$	33.84
GS>50kW-4,999 kW	$	518,208	37.78%	195,793	794	$	246.68
Sentinel Lights	$	37,807	68.36%	25,847	2,848	$	9.08
Street Lights	$	422,247	53.24%	224,788	34,670	$	6.48
Unmetered Scattered Load	$	19,972	48.30%	9,646	932	$	10.35
Total	$	8,862,688	55.50%	4,918,436			

Proposed Volumetric Charges:

The variable distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate 2013 Test Year usage, kWh or kW, as the class charge determinant.

The following Table provides IHDSL's calculations of its proposed variable distribution charges for the 2013 Test Year which maintains the same fixed/variable split used in designing the current approved rates.

Table 8.6 Proposed Distribution Volumetric Charge

Rate Classification	Total Net Rev Requirement	Total Fixed Revenue	Total Variable Revenue	Variable Revenue Proportion	Annualized kWh or kW	Unit of Measure	Proposed Variable Charge Before Transformer Allowance
Residential	7,234,973	4,092,953	3,142,020	43.43%	146,562,898	kWh	0.0214
GS<50kW	629,481	369,409	260,072	41.32%	31,437,455	kWh	0.0083
GS>50kW-4,999 kW	518,208	195,793	322,415	62.22%	146,480	kW	2.2011
Sentinel Lights	37,807	25,847	11,961	31.64%	289	kW	41.3339
Street Lights	422,247	224,788	197,460	46.76%	4,400	kW	44.8755
Unmetered Scattered Load	19,972	9,646	10,326	51.70%	592,220	kWh	0.0174
Total	**8,862,688**	**4,918,436**	**3,944,253**				

Proposed Adjustment for Transformer Allowance:

Currently, IHDSL provides a Transformer Allowance to those customers that own their transformation facilities. IHDSL 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 the Transformer Allowance expected to be provided to those GS > 50 kW customers that own their transformers is included in the GS > 50 kW volumetric charge. As a result, the proposed volumetric charge of $2.2011 per kW for the GS > 50 kW customer class is increased by $0.1141 per kW to include the amount of the Transformer Allowance in the GS > 50 kW class distribution volumetric rate. This means the total proposed distribution volumetric charge for the GS > 50 kW class will be $2.3152 per kW.

Proposed Distribution Rates: The following table sets out IHDSL's proposed 2012 electricity distribution rates based on the aforementioned calculations.

Table 8.7 Proposed Distribution Rates

Rate Classification	Proposed Fixed Monthly Service Charge		Unit of Measure	Proposed Volumetric Charge incl Transformer Allowance Adjustment
Residential	$	24.04	kWh	0.0214
GS<50kW	$	33.84	kWh	0.0083
GS>50kW-4,999 kW	$	246.68	kW	2.3152
Sentinel Lights	$	9.08	kW	41.3339
Street Lights	$	6.48	kW	44.8755
Unmetered Scattered Load	$	10.35	kWh	0.0174
Transformer Discount			kWh	-$0.60

Recovery of Low Voltage (LV) Costs:

Consistent with the approach in the Board's 2006 EDR model, LV costs of $509,329 have been allocated to each rate class based on the proportion of retail transmission connection revenue collected from each class. The amount of forecasted LV costs in 2013 is based on calculations shown in Table 8-8.

Table 8.8 Forecasted LV Costs

Rate Classification	Retail Transmission Connection Rate ($)		Basis for Allocation ($)	Allocation Percentages	Allocated $
	per KWh	per kW			
Residential	0.0040		628,121	64.40%	327,999
GS < 50 kW	0.0037		124,626	12.78%	65,079
GS >50 to 4999 kW		1.4516	212,630	21.80%	111,034
Sentinel Lights		1.1220	325	0.03%	170
Street Lighting		1.6635	7,320	0.75%	3,822
Unmetered and Scattered	0.0037		2,348	0.24%	1,226
TOTALS			**975,369**	**100.00%**	**509,329**

The calculation of proposed LV charges to recover the 2013 LV amount is outlined in the following table:

Table 8.9 Proposed LV Charges

Rate Classification	Unit of Measure	Retail Transmission Connection Rate	Basis for Allocation	Allocation Percentages	Allocation $	Annulaized kWh or kW	Proposed LV Charge
Residential	kWh	0.0040	628,121	64.40%	327,999	146,562,898	0.0022
GS<50kW	kWh	0.0037	124,626	12.78%	65,079	31,437,455	0.0021
GS>50kW-4,999 kW	kW	1.4516	212,630	21.80%	111,034	146,480	0.7580
Sentinel Lights	kW	1.1220	325	0.03%	170	289	0.5859
Street Lights	kW	1.6635	7,320	0.75%	3,822	4,400	0.8687
Unmetered Scattered Load	kWh	0.0037	2,348	0.24%	1,226	592,220	0.0021
			975,369	**100.00%**	**509,329**		

RETAIL TRANSMISSION SERVICE RATES

Electricity distributors are charged the Ontario Uniform Transmission Rates (UTRs) at the wholesale level and subsequently pass these charges on to their distribution customers through Retail Transmission Service Rates (RTSRs). For each distribution rate class there are two RTSRs, one for network and one for connection. The RTSR network charge recovers the UTR wholesale network service charge, and the RTSR connection charge recovers the UTR wholesale line and transformation connection charges. Deferral accounts capture timing and rate differences between the UTR's paid at the wholesale level and RTSR's billed to distribution customers.

The Board has provided a Microsoft Excel workbook "2013_RTSR_Adjustment_Work_Form" and instructions for distributors to complete as part of their 2013 electricity rate applications. IHDSL has completed this workbook to determine the RTSR's and has filed the model as part of this application. Table 8.10 is reproduced from the Board model and indicates the new RTSR's**.**

Table 8.10 Proposed RTSR Rates

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0050	$ 0.0040
General Service Less Than 50 kW	kWh	$ 0.0046	$ 0.0037
General Service 50 to 4,999 kW	kW	$ 1.8708	$ 1.4516
General Service 50 to 4,999 kW – Interval Metered	kW	$ 1.8119	$ 2.1284
Unmetered Scattered Load	kWh	$ 0.0046	$ 0.0037
Sentinel Lighting	kW	$ 1.4180	$ 1.6635
Street Lighting	kW	$ 1.4109	$ 1.1220

LOSS FACTOR

DETERMINATION OF LOSS ADJUSTMENT FACTORS:

Total Loss Factor:

IHDSL has calculated the total loss factor to be applied to customers' consumption based on the average wholesale and retail kWh for the years 2007 to 2011. The calculations are summarized in Table 8-13 below.

Table 8.11 Line Loss Calculation

		Historical Years					5-Year Average
		2007	2008	2009	2010	2011	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	241,154,636	245,623,028	247,239,189	250,239,379	246,758,167	246,202,880
A(2)	"Wholesale" kWh delivered to distributor (lower value)	235,121,981	240,965,463	240,653,353	244,035,081	240,111,859	240,177,547
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	235,121,981	240,965,463	240,653,353	244,035,081	240,111,859	240,177,547
D	"Retail" kWh delivered by distributor	224,169,495	226,442,150	229,263,240	231,788,047	231,635,167	228,659,620
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						-
F	Net "Retail" kWh delivered by distributor = **D - E**	224,169,495	226,442,150	229,263,240	231,788,047	231,635,167	228,659,620
G	Loss Factor in Distributor's system = **C / F**	1.0489	1.0641	1.0497	1.0528	1.0366	1.0504
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.026	1.019	1.027	1.025	1.028	1.025
	Total Losses						
I	Total Loss Factor = **G x H**	1.0761	1.0844	1.0780	1.0792	1.0656	1.0766

The supply facility loss factor (the "SFLF") shown in the above table represents the losses on supply to IHDSL. The SFLF is calculated on the measured quantities between the transformer stations and the wholesale meter points. The SFLF used in the calculations of the total loss factor above is based the weighted average of 2012 forecast of purchases from the IESO (1.0045) and Hydro One (1.0340).

Total Loss Factor by Class:

Table 8-11 sets out the class-specific Loss Factors used by IHDSL in the calculation of commodity and other non-distribution charges.

Table 8.12 Total Loss Factor by Class

Supply Facility Loss Factor	1.0250
Distribution Loss Factor	
Distribution Loss Factor - Secondary Metered Customer 5,000 kW	1.0504
Distribution Loss Factor - Primary Metered Customer < 5,000kW	1.0399
Total Loss Factor	
Total Loss Factor - Secondary Metered Customer < 5,000kW	1.0766
Total Loss Factor - Primary Metered Customer < 5,000kW	1.0659

Materiality Analysis on Distribution Losses:

IHDSL's Distribution Loss Adjustment factor is 5.04%. Pursuant to the Filing Requirements, as the Distribution Loss Adjustment factor is greater than 5%, IHDSL provides the following explanation of, or justification for, its loss adjustment factor.

As reflected in Table 8.11, IHDSL has made considerable progress in maintaining and improving the controllable factors contributing to line losses, for example tree trimming programs, diligent follow up on pot ential theft of power situations and scheduled capital investments for Infrastructure betterments.

The area in which IHDSL has minimal control is in sub-transmission switching, either for emergencies or planned switching. This is demonstrated by the increase in IHDSL's 2008 loss factor which increased by 1.52% over 2007. Extensive line losses were incurred when the Hydro One owned Alliston Transformer Station T1 and T2 bank sustained catastrophic failure directly

affecting the 9M1 and 9M4 supply from Alliston. At this time period, only three sub transmission feeders came into Innisfil which, in turn, left only one remaining 44kV feeder to support all of IHDSL load. The Barrie M3 supplied all the way down to our southernmost border. With the Barrie Transformer Station primary voltage at 115kV, it cannot transmit long distances efficiently like the Alliston TS with a primary voltage of 230kV, thus line losses occur outside of IHDSL's control.

RATE MITIGATION:

IHDSL has applied for a 2 year disposition of the Stranded Meter costs in the amount of $359,195 versus a one year period to assist with stabilization of rate increases. At a one year disposition, the impact to a Residential customer was $1.66 and $7.06 for a GS.50 kW versus $0.83 and $3.53.

In review of the bill impacts all rate classes are blow the 10% threshold with the exception of Sentinel Lights which has a total bill impact of 13.59%. This increase is directly attributed to the cost allocation ratios.

Rate Class	Distribution Impact	Delivery Impact	Total Bill Impact
Residential	**8.05%**	**6.09%**	**2.31%**
GS > 50kW	**-13.38%**	**-10.71%**	**-2.81%**
GS < 50kW	**-44.73%**	**-22.67%**	**-2.75%**
Street Lighting	**18.15%**	**17.44%**	**3.67%**
Sentinel Lights	**17.77%**	**17.74%**	**13.59%**
USL	**-56.46%**	**-54.11%**	**-36.31%**

SPECIFIC SERVICE CHARGES

IHDSL will not be submitting any specific service charges with this application.

EXISTING RATE CLASSES:

Residential:

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

General Service Less Than 50kW:

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. This class includes small commercial services such as small stores, small service stations, restaurants, churches, small offices and other establishments with similar loads.

General Service Greater Than 50 kW -4,999kW:

This classification refers to a non-residential account whose monthly average peak demand is greater than, or is forecast to be greater than, 50 kW but less than 5,000 kW. This class includes medium and large-size commercial buildings, apartment buildings, condominiums, trailer courts, industrial plants, as well as large stores, shopping centers, hospitals, manufacturing or processing plants, garages, storage buildings, restaurants, office buildings, hotels, motels, schools, colleges, arenas and other comparable premises.

Unmetered Scattered Load:

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, private sentinel lighting, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/ consumption of the proposed unmetered load.

Sentinel Lighting:

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light.

Street Lighting:

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photocells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

PROPOSED RATE CLASSES

IHDSL is proposing no new rate classes with this Cost of Service Application.

2012 EXISTING RATE SCHEDULE

IHDSL has enclosed the Board's Decision and Order from its 2012 Rate Application (EB-2011-0435/EB-2011-0176) which contains a complete schedule of existing rates.

GREEN ENERGY PLAN – FUNDING ADDER

IHDSL has submitted a basic Green Energy Plan to the OPA and has provided a copy in Appendix C. The OPA provided a Letter of Comment which has been provided in Appendix D.

As part of its GEA Plan, IHDSL has estimated the following capital and OM&A expenditures for 2013, 2014 and 2015.

IHDSL requests a funding adder to be included in its rates of $0.5233 (average of the 3 years) per Residential, GS>50kW and GS<50kW -4,999kW per month. The finding adder calculations were based on the Incremental Revenue Requirement Calculation provided below. An electronic version of this model has been provided as part of this application.

GEA Incremental Revenue Requirement Calculation

	2013		2014		2015		
Net Fixed Assets		$ 710,000		$260,000		$ 261,000	
OM&A	$ 75,000		$ 77,000		$ 80,000		
WCA	13.0%	$ 9,750	13.0%	$ 10,010	13.0%	$ 10,400	
Rate Base		$ 719,750		$270,010		$ 271,400	
Deemed ST Debt	4%	$ 28,790	4%	$ 10,800	4%	$ 10,856	
Deemed LT Debt	56%	$ 403,060	56%	$151,206	56%	$ 151,984	
Deemed Equity	40%	$ 287,900	40%	$108,004	40%	$ 108,560	
ST Interest	2.08%	$ 599	2.08%	$ 225	2.08%	$ 226	
LT Interest	5.11%	$ 20,596	5.11%	$ 7,727	5.11%	$ 7,766	
ROE	8.01%	$ 23,061	8.01%	$ 8,651	8.01%	$ 8,696	
		$ 44,256		$ 16,602		$ 16,688	
OM&A		**$ 75,000**		**$ 77,000**		**$ 80,000**	
Amortization		$ 25,278		$ 53,333		$ 58,889	
Grossed-up PILs		-$ 2,371		-$ 17,161		-$ 15,689	
Revenue Requirement		$ 142,163		$129,774		$ 139,887	
Direct Benefit							
OM&A		$ 75,000		$ 77,000		$ 80,000	
Capital		$ 67,163		$ 52,774		$ 59,887	
Direct Benefit % on capital		0.00%		55.25%		41.00%	
Direct Benefit on capital		$ -		$ 29,156		$ 24,552	
Total Direct Benefit		$ 75,000		$106,156		$ 104,552	
Total # of Customers (Residential, GS<>50)		15,165		15,165		15,165	
GEA Rate Adder		$ 0.4121		$ 0.5833		$ 0.5745	3 year average $ 0.5233
Provincial Rate Protection		$ 67,163		$ 23,619		$ 35,335	
Monthly Adder Amount Paid by IESO		$ 5,597		$ 1,968		$ 2,945	

IHDSL has divided its expected expenditures into two categories, Renewable Enabling Improvements and Feeder Automation Projects, and has estimated the amortization for each category based on the weighted average depreciation rates for the type of expenditures anticipated in 2013, using rates established under MIFRS. Renewable Improvements are depreciated over 45 years and Feeder Automation over 10 years. 6% of Renewable Enabling Improvements Enabling expenses have been designated as Direct Benefit, with the balance assigned to Provincial Rate Protection. Table 6.1 Renewable Capital Investment, contains these details.

Table 6.1 Renewable Capital Investment

Renewable Connections Capital - Renewable Enabling Improvements				
RECLOSER		**2013**	**2014**	**2015**
Opening Capital Investment		$ -	$ 250,000	$ 500,000
Capital Investment		$ 250,000	$ 250,000	$ 250,000
Closing Capital Investment		$ 250,000	$ 500,000	$ 750,000
Opening Accumulated Amortization		$ -	$ 2,778	$ 11,111
Amortization Year One	45 Years	$ 2,778	$ 2,778	$ 2,778
Amortization Thereafter		$ -	$ 5,556	$ 11,111
Closing Accumulated Amortization		$ 2,778	$ 11,111	$ 25,000
Opening Net Fixed Assets		$ -	$ 247,222	$ 488,889
Closing Net Fixed Assets		$ 247,222	$ 488,889	$ 725,000
Average Net Fixed Assets		$ 123,611	$ 368,056	$ 606,944
Feeder Automation Projects				
SCADA		**2013**	**2014**	**2014**
Opening Capital Investment		$ -	$ 450,000	$ 450,000
Capital Investment		$ 450,000	$ -	$ -
Closing Capital Investment		$ 450,000	$ 450,000	$ 450,000
Opening Accumulated Amortization		$ -	$ 22,500	$ 67,500
Amortization Year One	10 years	$ 22,500	$ -	$ -
Amortization Thereafter		$ -	$ 45,000	$ 45,000
Closing Accumulated Amortization		$ 22,500	$ 67,500	$ 112,500
Opening Net Fixed Assets		$ -	$ 427,500	$ 382,500
Closing Net Fixed Assets		$ 427,500	$ 382,500	$ 337,500
Average Net Fixed Assets		$ 213,750	$ 405,000	$ 360,000

Average Net Fixed Assets	**Direct Benefit %**	**2012**	**2013**	**2014**
Renewable Connections Capital - Expansions	17%	$ -	$ -	$ -
Renewable Connections Capital - Renewable Enabling Improvements	6%	$ 123,611	$ 368,056	$ 606,944
Feeder Automation Projects	100%	$ -	$ 405,000	$ 360,000
		$ 123,611	$ 773,056	$ 966,944
Direct Benefit		$ 7,417	$ 427,083	$ 396,417
Weighted Average Direct Benefit %		0.00%	55.25%	41.00%

Using these capital investment estimates IHDSL has estimated the incremental revenue requirement as shown below in Table 6.2. The incremental revenue calculation has been adjusted for PILS (Table 6.3). IHDSL proposes to recover $ 285,708 of this amount from its customers as a direct benefit thru a fixed monthly funding adder of $0.5233 p er customer. IHDSL proposes to recover the remaining through Provincial Rate Protection and requests a funding adder from the IESO for $3,503 per month.

When these costs are finalized at the end of 2015 IHDSL will come forward with a cost recovery application including a true-up rider and revenue collection rider to collect/disperse any variances from these amounts.

Table 6.2 Incremental Revenue Requirement & Funding Adder Calculation

Direct Benefit				
OM&A	$ 75,000	$ 77,000	$ 80,000	
Capital	$ 67,163	$ 52,774	$ 59,887	
Direct Benefit % on capital	0.00%	55.25%	41.00%	**Total for Recovery**
Direct Benefit on capital	$ -	$ 29,156	$ 24,552	**2013-2015**
Total Direct Benefit	$ 75,000	$106,156	$ 104,552	$ 285,708
Total # of Customers (Residential, GS<>50)	15,165	15,165	15,165	
				3 year average
GEA Rate Adder - Monthly Fixed Charge	$ 0.4121	$ 0.5833	$ 0.5745	$ 0.5233
Provincial Rate Protection	$ 67,163	$ 23,619	$ 35,335	$ 126,117
Monthly Adder Amount Paid by IESO	$ 5,597	$ 1,968	$ 2,945	$ 3,503

Table 6.3 PILS Calculation

PILs Calculation			
	2013	2014	2015
INCOME TAX			
Net Income	$ 23,061	$ 8,651	$ 8,696
Amortization	$ 25,278	$ 53,333	$ 58,889
CCA	-$ 55,000	-$ 110,200	-$ 111,664
Change in taxable income	-$ 6,661	-$ 48,216	-$ 44,079
Tax Rate	26.25%	26.25%	26.25%
Income Taxes Payable	-$ 1,749	-$ 12,657	-$ 11,571
ONTARIO CAPITAL TAX			
Closing Net Fixed Assets	$ 247,222	$ 488,889	$ 725,000
Less: Exemption	$ -	$ -	$ -
Deemed Taxable Capital	$ 247,222	$ 488,889	$ 725,000
Ontario Capital Tax Rate			
Net Amount (Taxable Capital x Rate)	$ -	$ -	$ -
Gross Up			
	PILs Payable	PILs Payable	PILs Payable
Change in Income Taxes Payable	-$ 1,748.63	-$ 12,656.58	-$ 11,570.86
Change in OCT	$ -	$ -	$ -
PIL's	-$ 1,748.63	-$ 12,656.58	-$ 11,570.86
	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs
Change in Income Taxes Payable	-$ 2,371.02	-$ 17,161.47	-$ 15,689.30
Change in OCT	$ -	$ -	$ -
PIL's	**-$ 2,371.02**	**-$ 17,161.47**	**-$ 15,689.30**

PROPOSED 2013 IHDSL TARIFF

IHDSL has provided the proposed 2013 Tariff Sheets in Appendix B.

RECONCILIATION OF RATE CLASS REVENUE

The following table provides the reconciliation between the 2013 distribution rate calculations based on the 2013 Proposed Rates and the total base revenue required. IHDSL has completed Appendix 2-V Revenue Reconciliation to produce the table.

Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
	Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
							kWh	kW					
Customers		14,189	14,189	146,562,898		$ 24.04	$ 0.0214		$ 7,234,973	$ 7,234,973		$ 7,234,973	$ -
Customers		910	910	31,437,455		$ 33.84	$ 0.0083		$ 629,481	$ 629,481		$ 629,481	$ -
Customers		66	66		146,480	$ 246.68		$ 2.3152	$ 534,923	$ 518,208	$ 16,715	$ 534,923	$ -
Connections		2,889	2,889		4,400	$ 6.48		$ 44.8755	$ 422,247	$ 422,247		$ 422,247	$ -
Connections		237	237		289	$ 9.08		$ 41.3339	$ 37,807	$ 37,807		$ 37,807	$ -
Connections		78	78	592,220		$ 10.35	$ 0.0174		$ 19,972	$ 19,972		$ 19,972	$ -
			-						$ -			$ -	$ -
			-						$ -			$ -	$ -
			-						$ -			$ -	$ -
		18369		178,592,573					$ 8,879,403	$ 8,862,688	$ 16,715	$ 8,879,403	$ -

RATE AND BILL IMPACTS:

Appendix A to this Exhibit 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 shown using the applicable current approved rates and the proposed 2013 distribution rates, including rate riders for the disposition of Deferral and Variance Accounts, as discussed in Exhibit 9.

Summary of bill impacts by rate class:

Rate Class	Distribution Impact	Delivery Impact	Total Bill Impact
Residential	**8.05%**	**6.09%**	**2.31%**
GS > 50kW	**-13.38%**	**-10.71%**	**-2.81%**
GS < 50kW	**-44.73%**	**-22.67%**	**-2.75%**
Street Lighting	**18.15%**	**17.44%**	**3.67%**
Sentinel Lights	**17.77%**	**17.74%**	**13.59%**
USL	**-56.46%**	**-54.11%**	**-36.31%**

Appendix A

Tariff of Existing Rates and Charges

Board File No: EB-2011-0435

DATED: May 17, 2012

Innisfil Hydro Distribution Systems Ltd.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

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

EB-2011-0176
EB-2011-0435

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to residential customers residing in detached, semi detached, townhouse (freehold or condominium) dwelling units duplexes or triplexes. Supply will be limited up to a maximum of 200 amp @ 240/120 volt. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	19.22
Rate Rider for Disposition of Residual Historical Smart Meter Costs – effective until April 30, 2014	$	0.27
Rate Rider for Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service-based rate order	$	1.86
Distribution Volumetric Rate	$/kWh	0.0188
Low Voltage Service Rate	$/kWh	0.0022
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2013	$/kWh	0.0005
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kWh	(0.0032)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	(0.0002) Rate
Rider for Tax Change – effective until April 30, 2013	$/kWh	(0.0005) Retail
Transmission Rate – Network Service Rate	$/kWh	0.0052
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Innisfil Hydro Distribution Systems Ltd.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

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

EB-2011-0176
EB-2011-0435

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly peak demand is less than or expected to be less than 50 kW. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	28.85
Rate Rider for Disposition of Residual Historical Smart Meter Costs – effective until April 30, 2014	$	0.92
Rate Rider for Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service-based rate order	$	6.33
Distribution Volumetric Rate	$/kWh	0.0086
Low Voltage Service Rate	$/kWh	0.0020
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2013	$/kWh	0.0004
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kWh	(0.0026)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	(0.0002)
Rate Rider for Tax Change – effective until April 30, 2013	$/kWh	(0.0002)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0038

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Innisfil Hydro Distribution Systems Ltd.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

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

EB-2011-0176
EB-2011-0435

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is expected to be equal to or greater than 50 kW but less than 5000 kW. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	320.64
Distribution Volumetric Rate	$/kW	2.9751
Low Voltage Service Rate	$/kW	0.7883
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2013	$/kW	0.1368
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kW	(0.7860)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	(0.0632)
Rate Rider for Tax Change – effective until April 30, 2013	$/kW	(0.0747)
Retail Transmission Rate – Network Service Rate	$/kW	1.9280
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4825
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	1.8673
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.1738

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Innisfil Hydro Distribution Systems Ltd.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

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

EB-2011-0176
EB-2011-0435

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 240/120 or 120 volts whose monthly peak demand is less than or expected to be less than 50 kW and the consumption is unmetered. A detailed calculation of the load will be calculated for billing purposes. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	23.51
Distribution Volumetric Rate	$/kWh	0.0396
Low Voltage Service Rate	$/kWh	0.0020
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2013	$/kWh	0.0005
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kWh	(0.0036)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	(0.0002)
Rate Rider for Tax Change – effective until April 30, 2013	$/kWh	(0.0011)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0038

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Innisfil Hydro Distribution Systems Ltd.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

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

EB-2011-0176
EB-2011-0435

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	7.64
Distribution Volumetric Rate	$/kW	34.7951
Low Voltage Service Rate	$/kW	0.6065
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2013	$/kW	0.1762
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kW	(1.3065)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	(0.0656)
Rate Rider for Tax Change – effective until April 30, 2013	$/kW	(1.2028)
Retail Transmission Rate – Network Service Rate	$/kW	1.4614
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1699

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Innisfil Hydro Distribution Systems Ltd.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

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EB-2011-0176
EB-2011-0435

STREET LIGHTING SERVICE CLASSIFICATION

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	5.39
Distribution Volumetric Rate	$/kW	37.3061
Low Voltage Service Rate	$/kW	1.6331
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2013	$/kW	0.1419
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kW	(0.9549)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	(0.0613)
Rate Rider for Tax Change – effective until April 30, 2013	$/kW	(1.0352)
Retail Transmission Rate – Network Service Rate	$/kW	1.4540
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1459

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Innisfil Hydro Distribution Systems Ltd.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

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EB-2011-0176
EB-2011-0435

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

Innisfil Hydro Distribution Systems Ltd.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

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EB-2011-0176
EB-2011-0435

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)

SPECIFIC SERVICE CHARGES

APPLICATION

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Customer Administration		
Arrears Certificate	$	15.00
Easement Letter	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned Cheque (plus bank charges)	$	15.00
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 at meter – during regular hours	$	40.00
Disconnect/Reconnect at Meter - after regular hours	$	185.00
Disconnect/Reconnect at Pole – during regular hours	$	185.00
Disconnect/Reconnect at Pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	40.00
Install/Remove load control device – after regular hours	$	185.00
Temporary service install and remove – overhead – no transformer	$	500.00
Temporary service install and remove – underground – no transformer	$	300.00
Temporary service install and remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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

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

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0746
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0638

Appendix B

Proposed Tariff of Rates and Charges

Board File No: EB-2012-0139

DRAFT

Innisfil Hydro Distribution Systems Ltd.

Proposed TARIFF OF RATES AND CHARGES for 2013

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

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to residential customers residing in detached, semi detached, townhouse (freehold or condominium) dwelling units duplexes or triplexes. Supply will be limited up to a maximum of 200 amp @ 240/120 volt. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge		$	24.04
Rate Rider for Disposition of Residual Historical Smart Meter Costs – effective until April 30, 2014		$	0.27
Rate Rider for Smart Meter –Stranded Meter – effective until April 30, 2015		$	0.83
Distribution Volumetric Rate		$/kWh	0.0214
Low Voltage Service Rate		$/kWh	0.0022
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014		$/kWh	(0.0032)
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until April 30, 2014		$/kWh	(0.0019)
Rate Rider for Global Adjustment Account Disposition (2012) - effective until April 30,2014 applicable only for Non-RPP Customers		$/kWh	(0.0002)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until April 30, 2014 applicable only for Non-RPP Customers		$/kWh	0.0062
GEA Rate Adder Rider– effective until April 30, 2016		$/kWh	0.5233
Retail Transmission Rate – Network Service Rate	$/kWh	0.0050	
Retail Transmission Rate – Line and Transformation Connection Service Rate		$/kWh	0.0040

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Innisfil Hydro Distribution Systems Ltd.
Proposed TARIFF OF RATES AND CHARGES for 2013

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

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly peak demand is less than or expected to be less than 50 kW. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge		$	33.84
Rate Rider for Disposition of Residual Historical Smart Meter Costs – effective until April 30, 2014		$	0.92
Rate Rider for Smart Meter – Stranded Meter – in effect until April 30. 2015		$	3.53
GEA Rate Adder Rider– effective until April 30, 2016	$ 0.5233		
Distribution Volumetric Rate		$/kWh	0.0083
Low Voltage Service Rate		$/kWh	0.0021
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014		$/kWh	(0.0026)
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until April 30, 2014		$/kWh	(0.0019)
Rate Rider for Global Adjustment Account Disposition (2012) - effective until April 30,2014 applicable only for Non-RPP Customers		$/kWh	(0.0002)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until April 30, 2014 applicable only for Non-RPP Customers		$/kWh	0.0062
Retail Transmission Rate – Network Service Rate		$/kWh	0.0046
Retail Transmission Rate – Line and Transformation Connection Service Rate		$/kWh	0.0037

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Innisfil Hydro Distribution Systems Ltd.
Proposed TARIFF OF RATES AND CHARGES 2013

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

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is expected to be equal to or greater than 50 kW but less than 5000 kW. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	246.68
Distribution Volumetric Rate	$/kW	2.3152
Low Voltage Service Rate	$/kW	0.7580
GEA Rate Adder Rider– effective until April 30, 2016	$	0.5233
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kW	(0.7860)
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until April 30, 2014	$/kW	(0.6695)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014 applicable only for Non-RPP Customers	$/kW	(0.0632)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until April 30, 2014 applicable only for Non-RPP customers	$/kW	2.1298
Retail Transmission Rate – Network Service Rate	$/kW	1.8708
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4516
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	1.8119
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.1284

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Innisfil Hydro Distribution Systems Ltd.
Proposed TARIFF OF RATES AND CHARGES

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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 240/120 or 120 volts whose monthly peak demand is less than or expected to be less than 50 kW and the consumption is unmetered. A detailed calculation of the load will be calculated for billing purposes. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	10.35
Distribution Volumetric Rate	$/kWh	0.0174
Low Voltage Service Rate	$/kWh	0.0021
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kWh	(0.0036)
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until April 30, 2014	$/kWh	(0.0019)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until April 30, 2014 applicable only for Non-RPP customers	$/kWh	(0.0002)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until April 30, 2014 Applicable only for Non-RPP customers	$k/Wh	0.0062
Retail Transmission Rate – Network Service Rate	$/kWh	0.0046
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0037

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Innisfil Hydro Distribution Systems Ltd.
Proposed TARIFF OF RATES AND CHARGES 2013

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SENTINEL LIGHTING SERVICE CLASSIFICATION

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	9.08
Distribution Volumetric Rate	$/kW	41.3339
Low Voltage Service Rate	$/kW	0.5859
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kW	(1.3065)
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until April 30, 2014	$/kW	(0.6946)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until April 30, 2014 applicable only for Non-RPP Customers	$/kW	2.2100
Rate Rider for Global Adjustment Sub-Account Disposition (2012) –effective until April 30, 2014 applicable only for Non-RPP customers	$/kW	(0.0656)
Retail Transmission Rate – Network Service Rate	$/kW	1.4180
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6635

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Innisfil Hydro Distribution Systems Ltd.
Proposed TARIFF OF RATES AND CHARGES 2013

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	6.48
Distribution Volumetric Rate	$/kW	44.8755
Low Voltage Service Rate	$/kW	0.8687
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kW	(0.9549)
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until April 30, 2014	$/kW	(0.6492)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014 applicable only for Non-RPP customers	$/kW	(0.0613)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until April 30, 2014 applicable only for Non-RPP Customers	$/kW	2.0655
Retail Transmission Rate – Network Service Rate	$/kW	1.4109
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1220

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Innisfil Hydro Distribution Systems Ltd.

Proposed TARIFF OF RATES AND CHARGES

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microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system.

APPLICATION

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No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

Innisfil Hydro Distribution Systems Ltd.

Proposed TARIFF OF RATES AND CHARGES

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

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)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration		
Arrears Certificate	$	15.00
Easement Letter	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned Cheque (plus bank charges)	$	15.00
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 at meter – during regular hours	$	40.00
Disconnect/Reconnect at Meter - after regular hours	$	185.00
Disconnect/Reconnect at Pole – during regular hours	$	185.00
Disconnect/Reconnect at Pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	40.00
Install/Remove load control device – after regular hours	$	185.00
Temporary service install and remove – overhead – no transformer	$	500.00
Temporary service install and remove – underground – no transformer	$	300.00
Temporary service install and remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Innisfil Hydro Distribution Systems Ltd.
Proposed TARIFF OF RATES AND CHARGES

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

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

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

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

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0766
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0659

APPENDIX C

TABLE OF RATE AND BILL IMPACTS

Residential Bill Impacts

Bill Impacts

Customer Class: Residential

Consumption 800 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 21.0800	1	$ 21.08	$ 24.0400	1	$ 24.04	$ 2.96	14.04%
Smart Meter Disposition Rider	Monthly	$ 0.2700	1	$ 0.27	$ 0.2700	1	$ 0.27	$ -	0.00%
Stranded Meter Rider	Monthly	$ -	1	$ -	$ 0.8300	1	$ 0.83	$ 0.83	
SMIRR	Monthly	$ 1.8600	1	$ 1.86	$ -	1	$ -	-$ 1.86	-100.00%
GEA Rate Adder	Monthly	$ -	1	$ -	$ 0.5233	1	$ 0.52	$ 0.52	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0188	800	$ 15.04	$ 0.0214	800	$ 17.12	$ 2.08	13.83%
LRAM & SSM Rate Rider	Monthly	$ -	800	$ -	$ -	800	$ -	$ -	
Sub-Total A				$ 38.25			$ 42.78	**$ 4.53**	**11.85%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0032	800	-$ 2.56	-$ 0.0051	800	-$ 4.08	-$ 1.52	59.38%
Low Voltage Service Charge	per kWh	$ 0.0022	800	$ 1.76	$ 0.0022	800	$ 1.76	$ -	0.00%
Smart Meter Entity Charge						800	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 37.45**			**$ 40.46**	**$ 3.01**	**8.05%**
RTSR - Network		$ 0.0052	860	$ 4.47	$ 0.0050	861	$ 4.31	-$ 0.16	-3.67%
RTSR - Line and Transformation Connection		$ 0.0041	860	$ 3.52	$ 0.0040	861	$ 3.45	-$ 0.08	-2.26%
Sub-Total C - Delivery (including Sub-Total B)				**$ 45.45**			**$ 48.21**	**$ 2.77**	**6.09%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	860	$ 4.47	$ 0.0052	861	$ 4.48	$ 0.01	0.19%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	860	$ 0.95	$ 0.0011	861	$ 0.95	$ 0.00	0.19%
Standard Supply Service Charge	Monthly	$ 0.2500	1-Jan-00	$ 0.25	$ 0.2500	1-Jan-00	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	860	$ 6.02	$ 0.0070	861	$ 6.03	$ 0.01	0.19%
Energy - RPP - Tier 1		$ 0.0750	0	$ -	$ 0.0750	0	$ -	$ -	
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	550	$ 35.76	$ 0.0650	551	$ 35.83	$ 0.07	0.19%
TOU - Mid Peak		$ 0.1000	155	$ 15.47	$ 0.1000	155	$ 15.50	$ 0.03	0.19%
TOU - On Peak		$ 0.1170	155	$ 18.10	$ 0.1170	155	$ 18.14	$ 0.03	0.19%
Total Bill on RPP (before Taxes)				**$ 57.13**			**$ 59.92**	**$ 2.79**	**4.89%**
HST		13%		$ 7.43	13%		$ 7.79	$ 0.36	4.89%
Total Bill (including HST)				$ 64.56			$ 67.71	$ 3.15	4.89%
Ontario Clean Energy Benefit [1]				-$ 6.46			-$ 6.77	-$ 0.31	4.80%
Total Bill on RPP (including OCEB)				**$ 58.10**			**$ 60.94**	**$ 2.84**	**4.90%**
Total Bill on TOU (before Taxes)				**$ 126.47**			**$ 129.39**	**$ 2.92**	**2.31%**
HST		13%		$ 16.44	13%		$ 16.82	$ 0.38	2.31%
Total Bill (including HST)				$ 142.91			$ 146.21	$ 3.30	2.31%
Ontario Clean Energy Benefit [1]				-$ 14.29			-$ 14.62	-$ 0.33	2.31%
Total Bill on TOU (including OCEB)				**$ 128.62**			**$ 131.59**	**$ 2.97**	**2.31%**
Loss Factor (%)		7.46%			7.66%				

GS>50 kW Bill Impacts

Customer Class: GS> 50 kW

Consumption 2000 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 35.1800	1	$ 35.18	$ 33.8400	1	$ 33.84	-$ 1.34	-3.81%
Smart Meter Disposition Rider	Monthly	$ 0.9200	1	$ 0.92	$ 0.9200	1	$ 0.92	$ -	0.00%
Stranded Meter Rider	Monthly	$ -	1	$ -	$ 3.5300	1	$ 3.53	$ 3.53	
SMIRR	Monthly	$ 6.3300	1	$ 6.33	$ -	1	$ -	-$ 6.33	-100.00%
GEA Rate Adder	Monthly	$ -	1	$ -	$ 0.5233	1	$ 0.52	$ 0.52	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0086	2000	$ 17.20	$ 0.0083	2000	$ 16.60	-$ 0.60	-3.49%
LRAM & SSM Rate Rider	Monthly	$ -	2000	$ -	$ -	2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Sub-Total A				$ 59.63			$ 55.41	**-$ 4.22**	**-7.07%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0026	2000	-$ 5.20	-$ 0.0045	2000	-$ 9.00	-$ 3.80	73.08%
Low Voltage Service Charge	per kWh	$ 0.0020	2000	$ 4.00	$ 0.0021	2000	$ 4.20	$ 0.20	5.00%
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 58.43**			**$ 50.61**	**-$ 7.82**	**-13.38%**
RTSR - Network		$ 0.0047	2149	$ 10.10	$ 0.0046	2153	$ 9.90	-$ 0.20	-1.95%
RTSR - Line and Transformation Connection		$ 0.0038	2149	$ 8.17	$ 0.0037	2153	$ 7.97	-$ 0.20	-2.45%
Sub-Total C - Delivery (including Sub-Total B)				**$ 76.70**			**$ 68.48**	**-$ 8.21**	**-10.71%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2149	$ 11.18	$ 0.0052	2153	$ 11.20	$ 0.02	0.19%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2149	$ 2.36	$ 0.0011	2153	$ 2.37	$ 0.00	0.19%
Standard Supply Service Charge	Monthly	$ 0.2500	1-Jan-00	$ 0.25	$ 0.2500	1-Jan-00	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2149	$ 15.04	$ 0.0070	2153	$ 15.07	$ 0.03	0.19%
Energy - RPP - Tier 1		$ 0.0750	0	$ -	$ 0.0750	0	$ -	$ -	
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	1375	$ 89.41	$ 0.0650	1378	$ 89.57	$ 0.17	0.19%
TOU - Mid Peak		$ 0.1000	387	$ 38.69	$ 0.1000	388	$ 38.76	$ 0.07	0.19%
TOU - On Peak		$ 0.1170	387	$ 45.26	$ 0.1170	388	$ 45.35	$ 0.08	0.19%
Total Bill on RPP (before Taxes)				**$ 105.53**			**$ 97.37**	**-$ 8.16**	**-7.73%**
HST		13%		$ 13.72	13%		$ 12.66	-$ 1.06	-7.73%
Total Bill (including HST)				$ 119.25			$ 110.03	-$ 9.22	-7.73%
Ontario Clean Energy Benefit [1]				-$ 11.93			-$ 11.00	$ 0.93	-7.80%
Total Bill on RPP (including OCEB)				**$ 107.32**			**$ 99.03**	**-$ 8.29**	**-7.73%**
Total Bill on TOU (before Taxes)				**$ 278.89**			**$ 271.05**	**-$ 7.84**	**-2.81%**
HST		13%		$ 36.26	13%		$ 35.24	-$ 1.02	-2.81%
Total Bill (including HST)				$ 315.14			$ 306.29	-$ 8.86	-2.81%
Ontario Clean Energy Benefit [1]				-$ 31.51			-$ 30.63	$ 0.88	-2.79%
Total Bill on TOU (including OCEB)				**$ 283.63**			**$ 275.66**	**-$ 7.98**	**-2.81%**

Loss Factor (%) 7.46% 7.66%

GS<50kW-4,999kW

Customer Class: General Service Greater Than 50KW

(●) May 1 - October 31 ( ) November 1 - April 30 (Select this radio button for applications filed after Oc

Consumption 1095000 kWh **Consumption** 2500 kW

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 320.6400	1	$ 320.64	$ 246.6800	1	$ 246.68	-$ 73.96	-23.07%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
GEA Rate Adder	Monthly	$ -	1	$ -	$ 0.5233	1	$ 0.52	$ 0.52	
Distribution Volumetric Rate	per kW	$ 2.9751	2500	$ 7,437.75	$ 2.3152	2500	$ 5,788.00	-$ 1,649.75	-22.18%
LRAM & SSM Rate Rider	per kW	$ -	2500	$ -		2500	$ -	$ -	
Sub-Total A				$ 7,758.39			$ 6,035.20	**-$ 1,723.19**	**-22.21%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.7860	2500	-$ 1,965.00	-$ 1.4555	2500	-$ 3,638.75	-$ 1,673.75	85.18%
Low Voltage Service Charge	per kW	$ 0.7883	2500	$ 1,970.75	$ 0.7580	2500	$ 1,895.00	-$ 75.75	-3.84%
	Monthly					1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 7,764.14**			**$ 4,291.45**	**-$ 3,472.69**	**-44.73%**
RTSR - Network	per kW	$ 1.9280	2500	$ 4,820.00	$ 1.8708	2500	$ 4,677.00	-$ 143.00	-2.97%
RTSR - Line and Transformation Connection	per kW	$ 1.4825	2500	$ 3,706.25	$ 1.4516	2500	$ 3,629.00	-$ 77.25	-2.08%
Sub-Total C - Delivery (including Sub-Total B)				**$ 16,290.39**			**$ 12,597.45**	**-$ 3,692.94**	**-22.67%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	1176687	$ 6,118.77	$ 0.0052	1178877	$ 6,130.16	$ 11.39	0.19%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	1176687	$ 1,294.36	$ 0.0011	1178877	$ 1,296.76	$ 2.41	0.19%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1176687	$ 8,236.81	$ 0.0070	1178877	$ 8,252.14	$ 15.33	0.19%
Energy - RPP - Tier 1		$ 0.0750		$ -	$ 0.0750		$ -	$ -	
Energy - RPP - Tier 2		$ 0.0880		$ -	$ 0.0880		$ -	$ -	
Energy - Commodity COP	per kWh	$ 0.0807	1176687	$ 94,946.87	$ 0.0807	1178877	$ 95,123.59	$ 176.71	0.19%
		$ 0.1000		$ -	$ 0.1000		$ -	$ -	
		$ 0.1170		$ -	$ 0.1170		$ -	$ -	
Total Bill on Commodity COP				**$126,887.45**			**$ 123,400.35**	**-$ 3,487.10**	**-2.75%**
HST		13%		$ 16,495.37	13%		$ 16,042.05	-$ 453.32	-2.75%
Total Bill (including HST)				$143,382.82			$ 139,442.40	-$ 3,940.42	-2.75%
Ontario Clean Energy Benefit [1]				-$ 14,338.28			-$ 13,944.24	$ 394.04	-2.75%
Total Bill on TOU (including OCEB)				**$129,044.54**			**$ 125,498.16**	**-$ 3,546.38**	**-2.75%**
Loss Factor (%)		7.4600%			7.6600%				

Sentinel Light Bill Impacts

Customer Class:	Sentinel Lights										
		○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oc									
	Consumption	180	kWh		Consumption		1	kW			
		Current Board-Approved			Proposed			Impact			
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change		
Monthly Service Charge	Monthly	$ 7.6400	3	$ 22.92	$ 9.0757	3	$ 27.23	$ 4.31	18.79%		
Smart Meter Rate Adder			1	$ -		1	$ -	$ -			
Distribution Volumetric Rate	per kW	$ 34.7951	1	$ 34.80	$ 41.3339	1	$ 41.33	$ 6.54	18.79%		
Sub-Total A				$ 57.72			$ 68.56	**$ 10.85**	**18.79%**		
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.3065	1	-$ 1.31	-$ 2.0011	1	-$ 2.00	-$ 0.69	53.16%		
Low Voltage Service Charge	per kW	$ 0.6065	1	$ 0.61	$ 0.5859	1	$ 0.59	-$ 0.02	-3.40%		
Smart Meter Entity Charge	Monthly					1	$ -	$ -			
Sub-Total B - Distribution (includes Sub-Total A)				**$ 57.02**			**$ 67.15**	**$ 10.13**	**17.77%**		
RTSR - Network	per kW	$ 1.4614	1	$ 1.46	$ 1.4180	1	$ 1.42	-$ 0.04	-2.97%		
RTSR - Line and Transformation Connection	per kW	$ 1.1699	1	$ 1.17	$ 1.6635	1	$ 1.66	$ 0.49	42.19%		
Sub-Total C - Delivery (including Sub-Total B)				**$ 59.65**			**$ 70.23**	**$ 10.58**	**17.74%**		
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	193	$ 1.01	$ 0.0052	194	$ 1.01	$ 0.00	0.19%		
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	193	$ 0.21	$ 0.0011	194	$ 0.21	$ 0.00	0.19%		
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%		
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	193	$ 1.35	$ 0.0070	194	$ 1.36	$ 0.00	0.19%		
Energy - RPP - Tier 1		$ 0.0750		$ -	$ 0.0750		$ -	$ -			
Energy - RPP - Tier 2		$ 0.0880		$ -	$ 0.0880		$ -	$ -			
Energy - Commodity COP	per kWh	$ 0.0807	193	$ 15.61	$ 0.0807	194	$ 15.64	$ 0.03	0.19%		
		$ 0.1000		$ -	$ 0.1000		$ -	$ -			
		$ 0.1170		$ -	$ 0.1170		$ -	$ -			
Total Bill on Commodity COP				**$ 78.08**			**$ 88.69**	**$ 10.61**	**13.60%**		
HST		13%		$ 10.15	13%		$ 11.53	$ 1.38	13.60%		
Total Bill (including HST)				$ 88.23			$ 100.22	$ 11.99	13.60%		
Ontario Clean Energy Benefit [1]				-$ 8.82			-$ 10.02	-$ 1.20	13.61%		
Total Bill on TOU (including OCEB)				**$ 79.41**			**$ 90.20**	**$ 10.79**	**13.59%**		
Loss Factor (%)		7.4600%			7.6600%						

Street Lighting Bill Impacts

Customer Class: Streetlights

Consumption 108,831 kWh — (●) May 1 - October 31 ( ) November 1 - April 30 (Select this radio button for applications filed after Oc — **Consumption** 37 KW

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 5.3900	238	$ 1,282.82	$ 6.4836	238	$ 1,543.10	$ 260.28	20.29%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 37.3061	37	$ 1,380.33	$ 44.8755	37	$ 1,660.39	$ 280.07	20.29%
Sub-Total A				$ 2,663.15			$ 3,203.49	**$ 540.34**	**20.29%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.9549	37	-$ 35.33	-$ 1.6041	37	-$ 59.35	-$ 24.02	67.99%
Low Voltage Service Charge	per kW	$ 1.6331	37	$ 60.42	$ 0.8687	37	$ 32.14	-$ 28.28	-46.81%
Smart Meter Entity Charge	Monthly					1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 2,688.24**			**$ 3,176.28**	**$ 488.04**	**18.15%**
RTSR - Network	per kW	$ 1.4540	37	$ 53.80	$ 1.4109	37	$ 52.20	-$ 1.59	-2.96%
RTSR - Line and Transformation Connection	per kW	$ 1.1459	37	$ 42.40	$ 1.1220	37	$ 41.51	-$ 0.88	-2.09%
Sub-Total C - Delivery (including Sub-Total B)				**$ 2,784.44**			**$ 3,270.00**	**$ 485.56**	**17.44%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	116950	$ 608.14	$ 0.0052	117167	$ 609.27	$ 1.13	0.19%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	116950	$ 128.64	$ 0.0011	117167	$ 128.88	$ 0.24	0.19%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	116950	$ 818.65	$ 0.0070	117167	$ 820.17	$ 1.52	0.19%
Energy - RPP - Tier 1		$ 0.0750		$ -	$ 0.0750		$ -	$ -	
Energy - RPP - Tier 2		$ 0.0880		$ -	$ 0.0880		$ -	$ -	
Energy - Commodity COP	per kWh	$ 0.0807	116950	$ 9,436.68	$ 0.0807	117167	$ 9,454.24	$ 17.56	0.19%
		$ 0.1000		$ -	$ 0.1000		$ -	$ -	
		$ 0.1170		$ -	$ 0.1170		$ -	$ -	
Total Bill on Commodity COP				**$ 13,776.80**			**$ 14,282.82**	**$ 506.02**	**3.67%**
HST		13%		$ 1,790.98	13%		$ 1,856.77	$ 65.78	3.67%
Total Bill (including HST)				$ 15,567.78			$ 16,139.58	$ 571.80	3.67%
Ontario Clean Energy Benefit [1]				-$ 1,556.78			-$ 1,613.96	-$ 57.18	3.67%
Total Bill on TOU (including OCEB)				**$ 14,011.00**			**$ 14,525.62**	**$ 514.62**	**3.67%**
Loss Factor (%)		7.4600%			7.6600%				

Unmetered Scattered Load Bill Impacts

Customer Class: **Unmetered Scattered Load**

(●) May 1 - October 31 ( ) November 1 - April 30 (Select this radio button for applications filed

Consumption 150 kWh **Consumption** 1 KW

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 23.5100	1	$ 23.51	$ 10.3515	1	$ 10.35	-$ 13.16	-55.97%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 0.0396	161	$ 6.38	$ 0.0174	161	$ 2.80	-$ 3.58	-56.06%
Sub-Total A				$ 29.89			$ 13.16	**-$ 16.74**	**-55.99%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.0036	1	-$ 0.00	-$ 0.0055	1	-$ 0.01	-$ 0.00	52.78%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.0020	161	$ 0.32	$ 0.0021	1	$ 0.00	-$ 0.32	-99.35%
Smart Meter Entity Charge	Monthly					1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 30.21**			**$ 13.15**	**-$ 17.06**	**-56.46%**
RTSR - Network	per kW	$ 0.0047	161	$ 0.76	$ 0.0046	161	$ 0.74	-$ 0.01	-1.95%
RTSR - Line and Transformation Connection	per kW	$ 0.0038	161	$ 0.61	$ 0.0037	161	$ 0.60	-$ 0.02	-2.45%
Sub-Total C - Delivery (including Sub-Total B)				**$ 31.58**			**$ 14.49**	**-$ 17.09**	**-54.11%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	161.19	$ 0.84	$ 0.0052	161.49	$ 0.84	$ 0.00	0.19%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	161.19	$ 0.18	$ 0.0011	161.49	$ 0.18	$ 0.00	0.19%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	161.19	$ 1.13	$ 0.0070	161.49	$ 1.13	$ 0.00	0.19%
Energy - RPP - Tier 1		$ 0.0750		$ -	$ 0.0750		$ -	$ -	
Energy - RPP - Tier 2		$ 0.0880		$ -	$ 0.0880		$ -	$ -	
Energy - Commodity COP	per kWh	$ 0.0807	161.19	$ 13.01	$ 0.0807	161.49	$ 13.03	$ 0.02	0.19%
		$ 0.1000		$ -	$ 0.1000		$ -	$ -	
		$ 0.1170		$ -	$ 0.1170		$ -	$ -	
Total Bill on Commodity COP				**$ 46.98**			**$ 29.92**	**-$ 17.06**	**-36.31%**
HST		13%		$ 6.11	13%		$ 3.89	-$ 2.22	-36.31%
Total Bill (including HST)				$ 53.09			$ 33.81	-$ 19.28	-36.31%
Ontario Clean Energy Benefit [1]				-$ 5.31			-$ 3.38	$ 1.93	-36.35%
Total Bill on TOU (including OCEB)				**$ 47.78**			**$ 30.43**	**-$ 17.35**	**-36.31%**
Loss Factor (%)		7.4600%			7.6600%				

Exhibit	Tab	Schedule	Appendix	Contents
9 – Deferral and Variance Accounts				
	1	1		Overview
		2		Previous Deferral and Variance Account Disposition
	2	1		Status of Deferral and Variance Accounts
		2		Deferral and Variance Account Balances
		3		Method and Accounts Requested for Disposition
	3	1		Stranded Meter Costs
	4	1		Green Energy Plan - Funding Adder
			A	Revised 2012 EDVVAR Model for Non-RPP Global Adjustment Amount
			B	Revised 2012 EDVVAR Model excluding Non-RPP Global Adjustment Amount

DEFERRAL AND VARIANCE ACCOUNTS:

OVERVIEW

The information contained in this exhibit includes the status and description of IHDSL's deferral and variance accounts, the proposed disposition of certain account balances, and the rate riders required for recovery or refund of the account balances.

PREVIOUS DEFERRAL AND VARIANCE ACCOUNT DISPOSITION

2012 IRM Approval and Board Directive

On May 1, 2012 the Ontario Energy Board's Decision and Order EB-2012-0176 and EB-2011-0435 approved a 2 year disposition for IHDSL's December 31, 2009 Group 1 account balances and variance account balances in the amount of ($708,535) which includes a balance of ($27,194) in the 1588 global adjustment sub-account.

In 2012, the approve balances were transferred to a sub-account of 1595 as directed in the Decision and Order. The corresponding rate riders for the refund of the approved balances are in effect until April 30, 2014.

Table 9.1 2012 IRM EB-2011-0176/EB-2011-0435

Account Name	Account Number	Principal Balance	Interest Balance	Total Claim
LV Variance Account	1550	-$ 218,767	-$ 8,788	-$ 227,555
RSVA-Wholesale Market Service Charge	1580	-$ 248,962	-$ 10,507	-$ 259,469
RSVA-Retail Transmission Network	1584	$ 36,888	-$ 4,297	$ 32,591
RSVA-Retail Transmission Connection	1586	-$ 113,473	$ 1,393	-$ 112,080
RSVA-Power (excl Global Adjustment)	1588	-$ 117,209	$ 2,381	-$ 114,828
RSVA-Power Global Adjustment	1588	-$ 30,716	$ 3,522	-$ 27,194
Group 1 Total		**-$ 692,239**	**-$ 16,296**	**-$ 708,535**

2011 IRM

On April 8th 2011 the Board's Decision and Order EB-2010-0093 approved a one year disposition for IHDSL's December 31, 2008 Group 1 account balances and variance account balances in the amount of ($143,431) and includes a balance of $206,975 in the 1588 global adjustment sub-account. The account balances were transferred to account 1595 and rates for disposition are approved until April 30, 2012.

In 2011, the approved balances were transferred to a sub-account of 1595 as directed in the Decision and Order. The corresponding rate riders for the refund of the approved balances are in effect until April 30, 2012.

Table 9.2 2011 IRM EB-2010-0093

Account Name	Account Number	Principal Balance	Interest Balance	Total Claim
LV Variance Account	1550	-$ 162,267	$ 322	-$ 161,945
RSVA-Wholesale Market Service Charge	1580	-$ 65,594	$ 52	-$ 65,542
RSVA-Retail Transmission Network	1584	-$ 103,839	-$ 833	-$ 104,672
RSVA-Retail Transmission Connection	1586	-$ 40,508	-$ 1,565	-$ 42,073
RSVA-Power (excl Global Adjustment)	1588	$ 28,713	$ 3,272	$ 31,985
RSVA-Power Global Adjustment	1588	$ 208,797	-$ 1,822	$ 206,975
Recovery of Regulatory Asset Balances	1590	-$ 705	-$ 7,454	-$ 8,159
Group 1 Total		**-$ 135,403**	**-$ 8,028**	**-$ 143,431**

STATUS OF DEFERRAL AND VARIANCE ACCOUNTS:

This Schedule contains the status of Deferral and Variance Accounts ("DVAs") currently used by IHDSL. The balances as at December 31, 2011 and the proposed recovery amounts are summarized in Table 2.1 following the descriptions of each account:

GROUP 1 ACCOUNTS

1550 LV Variance Account

This Account is used to record the net of the low voltage transactions, which are not part of the electricity wholesale market. Monthly this account is used to record the net amounts charged by host distributor(s) to an embedded distributor for transmission or low voltage services (USoA 4750) and the amount billed to the embedded distributor's customers based on approved LV rate(s) (USoA 4075).

The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, IHDSL is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1580. T he requested amount is a credit of ($44,692).

1580 Retail Settlement Variance Account - Wholesale Market Service Charges

This account is used to record the net of the amount charged by the IESO based on the settlement invoice for the operation of the IESO-administered markets and the operation of the IESO-controlled grid, and the amount billed to customers using the OEB-approved Wholesale Market Service Rate. IHDSL uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, IHDSL is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1580. T he requested amount is a credit of ($297,061).

1584 Retail Settlement Variance Account - Retail Transmission Network Charges

This account is used to record the net of the amount charged by the IESO, based on the settlement invoice for transmission network services, and the amount billed to customers using the OEB-approved Retail Transmission Rate for network services. IHDSL uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, IHDSL is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1584. T he requested amount is a credit of ($20,010).

1586 Retail Settlement Variance Account - Retail Transmission Connection Charges

This account is used to record the net of the amount charged by the IESO, based on the settlement invoice for transmission connection services, and the amount billed to customers using the OEB-approved Retail Transmission Rate for connection services. IHDSL uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, IHDSL is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1586. T he requested amount is a credit of ($101,048).

1588 Retail Settlement Variance Account – Power (excluding Global Adjustment)

This account is used to recover the net difference between the energy amount billed to customers and the energy charge to IHDSL using the settlement invoice from the

Independent Electricity System Operator (IESO). IHDSL uses the accrual method. The variance between Board-approved and actual line losses is reflected in Account 1588 for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, IHDSL is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1588 - Power. The requested amount is a credit of ($253,571).

1588 Retail Settlement Variance Account - Power, Sub-account Global Adjustment

This account is used to recover the net difference between the provincial benefit amount billed to customers and the global adjustment charge to IHDSL using the settlement invoice from the IESO. IHDSL uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, IHDSL is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1588 sub account Global Adjustment through a separate non-RPP rate rider. The requested amount is a debit of $458,109.

1595 Disposition and Recovery of Regulatory Balances

This account includes the regulatory asset or liability balances authorized by the Board for recovery in rates or payments/credits made to customers. Separate sub-accounts are maintained for expenses, interest, and recovery amounts for each Board-approved recovery.

For 2013 IHDSL is requesting disposition of the December 31, 2011 audited balance of plus the forecasted interest through April 30, 2013 for account 1595 - sub account 2010. The requested amount is a credit of ($94,192).

Sub-Account 2009 for EB-2008-0233: In accordance with the OEB EB-2008-0233 Decision and Order for IHDSL's 2009 COS Application, the December 31, 2007 debit balance of $422,990 including interest forecast to April 30, 2009 was transferred to a sub-account of 1595 in April 2010. The recovery of this balance will be completed effective April 30, 2013.

Sub-Account 2010 for EB-2009-0232: In accordance with the OEB EB-2009-0232 Decision and Order for IHDSL's 2010 IRM, the December 31, 2008 debit balance of $660,983 including interest forecast to April 30, 2010 was transferred to a sub-account of 1595 in April 2010. As of April 30, 2011, the disposition period for this account was completed.

Sub-Account 2011 for EB-2010-0093: In accordance with the OEB EB-2010-0099 Decision and Order for IHDSL's 2011 IRM, the December 31, 2009 credit balance of ($143,431), excluding the global adjustment sub-account, but including interest forecast to April 30, 2011 was transferred to a sub-account of 1595 in April 2011. As of April 30, 2012 the disposition period for Group 1 balances, excluding the global adjustment, was completed.

GROUP 2 ACCOUNTS

1508 Other Regulatory Assets - Sub-account OEB Cost Assessments

This account includes amounts paid for OEB Cost Assessment for the period January 1, 2005 to April 30, 2007 in excess of amounts previously included in rates (1999 OEB costs). The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

1508 Other Regulatory Assets - Sub-account Pension Contributions

This account includes amounts paid for OMERS pension expense for the period January 1, 2005 to April 30, 2007 not included in rates. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

1508 Other Regulatory Assets – Sub-account IFRS Transition Costs

This account includes amounts paid for one-time incremental costs for the transition to International Financial Reporting Standards (IFRS). The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

This account includes amounts paid for one-time incremental International Financial Reporting Standards (IFRS) transition costs not included in rates, until the transition to IFRS has commenced. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

IHDSL established Account 1508 – sub account – Deferred IFRS Transition Costs in accordance with the Board requirements. In the Board's Accounting Procedures Handbook Frequently Asked Questions October 2009 ("APH-FAQ October 2009"), the Board permitted the deferral of one-time administrative costs caused by the transition of accounting policies, procedures, systems, and processes to International Financial.

Reporting Standards ("IFRS") in this sub-account. Also in the Board's Accounting Procedures Handbook Frequently Asked Questions October 2009 ("APH-FAQ October 2009"), the Board permitted interest carrying charges to be calculated on the monthly opening principal balance of this sub-account at the Board's prescribed interest rates. Based on this guidance, IHDSL commenced to defer professional accounting fees, incremental salaries, wages, and benefits of staff attributable to the transition to IFRS, staff training costs solely related to IFRS and carrying charges solely related to these items.

IHDSL is seeking disposition of the December 31, 2011 audited balance of $308,464 for one-time transition/administrative costs in this Application which includes carrying charges up to April 30, 2013.

Table 9.3 One Time Incremental IFRS Transition Costs

Nature of One-Time Incremental IFRS Transition Costs [1]	Audited Actual Costs Incurred 2009	Audited Actual Costs Incurred 2010	Audited Actual Costs Incurred 2011	Audited Carrying Charges to Dec 31, 2011	Total Audited Actual Costs to Dec 31, 2011	RRR 2.1.7 Balance 31-Dec-11	Variance [2]	Reasons why the costs recorded meet the criteria of one-time IFRS administrative incremental costs
professional accounting fees	$ 7,813	$ 85,046	$ 10,495		$ 103,354			One time costs incurred to create an distribution open item asset listing
professional legal fees					$ -			
salaries, wages and benefits of staff added to support the transition to IFRS					$ -			
associated staff training and development costs	$ 2,874				$ 2,874			One time initial training costs
costs related to system upgrades, or replacements or changes where IFRS was the major reason for conversion	$ 1,246	$ 53,175	$ 195,484		$ 249,905			Initial setup costs incurred to develop and implement a identifiable asset process within GIS and financial reporting system for disposition referencing.
					$ -			
Recovery of estimated IFRS costs from ratepayers	-$ 16,667	-$ 25,000	-$ 25,000		-$ 66,667			
Total net carrying charges				$ 3,354	$ 3,354			
					$ -			
					$ -			
					$ -			
					$ -			
Insert description of additional item(s) and new rows if needed.					$ -			
Total	-$ 4,734	$ 113,221	$ 180,979	$ 3,354	$ 292,820	$ 292,820	$ -	

The majority of the incremental IFRS transition costs relate to third party consultants that were used to help implement IFRS. This includes consultancy costs from BDO to assist with IFRS implementation within IHDSL. BDO was hired to assist with the transitional analysis, analysis regarding fixed assets componentization, useful lives, and overheads. This work was completed with the assistance of IHDSL contract staff and in consultation with external auditors by the end of December 31, 2011. These costs would not be incurred if IHDSL was not required to transition to IFRS.

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The remaining costs included in this account relate to other resources that were used to assist in preparing the documentation of our new policies, procedures and process flows as a result of implementing IFRS. There were also costs included in this account for incremental labour costs of staff to work on the IFRS project and training. These costs would not have been incurred if IHDSL had not been required to transition to IFRS.

IHDSL confirms these costs are not already approved and included for recovery in distribution rates. IHDSL also confirms the balance requested for disposition does not include ongoing IFRS compliance costs, impacts arising from adopting accounting policy changes that reflect changes in the timing of the recognition of income, costs related to system upgrades where IFRS was not the major reason for conversion, and costs that are capital in nature.

CONTINUATION OF IFRS TRANSITION COST SUB – ACCOUNT 1508

In 2010, the OEB approved 1508 – Other Regulatory Assets – Sub Account – Deferred IFRS Transition Costs, to record incremental costs incurred in relation to the transition to International Financial Reporting Standards (IFRS). The July 28, 2009 Report of the Board EB-2008-0408, Transition to International Financial Reporting Standards, stated "As required by the Canadian Accounting Standards Board, Canadian Generally Accepted Accounting Principles (CGAAP) for publically accountable enterprises will transition to IFRS effective January 1, 2011". It was expected by the Board that incremental transition costs incurred after the January 1, 2011 were expected to be minimal.

On July 20 and 22, 2010, the International Accounting Standards Board (IASB) held deliberations on rate-regulated activities and made the decision to continue with its project addressing the recognition, measurement and disclosure of regulatory assets and liabilities, and not to develop transitional guidance for use by first-time adopters. The

Canadian Accounting Standards Board (AcSB) discussed these developments and decided to amend the CICA Handbook to require that qualifying entities with rate-regulated activities adopt IFRS for the first time no later than fiscal periods beginning on or after January 1, 2012. Entities electing to defer the first time adoption of IFRS must also disclose that fact.

On March 20, 2012, the Canadian Accounting Standards Board ("AcSB") announced on March 30, 2012 that it would again extend the deferral of the mandatory IFRS changeover date for entities with qualifying rate regulated activities by one year to January 1, 2013. The deferral of the mandatory changeover date for an additional year would permit the AcSB to consider the actions it might take should the IASB add to its agenda a project on the effects of rate regulation.

As a qualifying entity, IHDSL will be in a position to implement IFRS on January 1, 2013, pending future decisions and direction from the IASB, the AcSB, and the OEB. Until then, IHDSL will continue to incur costs associated with the transition to IFRS. IHDSL therefore requests the continuation of the 1508 – Other Regulatory Assets – Sub Account – Deferred IFRS Transition Costs for disposition in a future rate proceeding.

IHDSL has incurred additional professional accounting fees and salaries, wages and benefits expenses in 2012. Consequently, IHDSL is requesting disposition of the 2011 balance only and respectfully requests continuation of the IFRS Transition Cost sub-account 1508 for disposition in a future rate proceeding.

1508 Other Regulatory Assets – Sub-account Incremental Capital Charges

This account contains the incremental capital charges from Hydro One.

1518 Retail Settlement Variance Account – Retail

This account is used to recover the net differences between the revenues recovered from Retailer Service Agreements and Billing options and the cost of managing the retailer contracts.

The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, IHDSL is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1518 – RCVA Retail. The requested amount is a debit $31,337.

1548 Retail Settlement Variance Account – Service Transaction Request

This account is used to recover the net differences between the revenues recovered from Service Transaction Requests (as described in the 2000 EDRH) and the incremental costs of providing these services.

The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, IHDSL is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1548 – RCVA STR. The requested amount is a debit of $85,638.

1572 Extraordinary Event Costs

This account records the costs of extraordinary events which are not recovered in current rates. As at December 31, 2011 the balance in this account was zero.

1582 Retail Settlement Variance Account - One-time Wholesale Market Service

This account is used to record the net of non-recurring amounts not included in the Wholesale Market Service Rate charged by the IESO based on the settlement invoice and the amount charged to customers for the same services using the OEB-approved rate. IHDSL uses the accrual method and has used this method consistently over time for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

IHDSL is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1582. The requested amount is a debit of $83,141.

2425Other Deferred Credits

This account shall include advance billings and receipts and other deferred credit items, not provided for elsewhere, including amounts which cannot be entirely cleared or disposed of until additional information has been received.

IHDSL is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 2425. The requested amount is a credit of ($98,782).

1592 PILs and Tax Variance for 2006 and Subsequent Years – Sub-account HST/OVAT Input Tax Credits (ITC's)

This account is used to record the incremental ITC received in distribution revenue requirement previously subject to PST and now become subject to HST. Tracking of these amounts will continue in this deferral account until the effective date of IHDSL's next cost of service rate order. 50 percent of the confirmed balance in this account shall be returnable to the ratepayers.

Account 1592 – Sub-account HST includes a credit balance of ($43,209) which represents 50% of the HST balance at December 31, 2011. For 2013, IHDSL is requesting disposition of the December 31, 2011 audited balance plus forecasted interest through April 30, 2013.

IHDSL requests leave to discontinue tracking HST/OVAT/ITC as of December 31, 2012. IHDSL is filing a Cost of Service Rate Application, and as explained in Chapter 2 of the Filing Requirements, once IHDSL rebases, the HST impacts would be included in rates going forward.

IHDSL requests the Board to allow account 1592 to remain open, pending Board approval to discontinue tracking costs, and until such time as IHDSL files its 2014 IRM rate application at which time IHDSL will apply to the Board for an order to clear any audited debit or credit balance remaining in account 1592 Sub account HST.

IHDSL used the simplified method outlined in the FAQ's of December 23, 2010 to calculate a detailed one time analysis based on our most recent historic year 2009 to identify the PST included in our OM&A costs and capital spending which would have been removed by the elimination of the PST.

ACCOUNT BALANCES

The following table contains account balances from the 2011 Audited Financial Statements as at December 31, 2011 and agrees to the 2011 year end balances for RRR filing E2.1.7 Trial Balance as filed April 30, 2012 with the OEB.

Table 9.4 Summary of December 31, 2011 Audited Balances

Group 1 Accounts	Account Number	Principal Balance	Interest Balance	Total Claim
LV Variance Account	1550	-$ 46,364	$ 1,672	-$ 44,692
RSVA-Wholesale Market Service Charge	1580	-$ 291,192	-$ 5,869	-$ 297,061
RSVA-Retail Transmission Network	1584	-$ 20,724	$ 714	-$ 20,010
RSVA-Retail Transmission Connection	1586	-$ 99,359	-$ 1,689	-$ 101,048
RSVA-Power (excl Global Adjustment)	1588	-$ 248,519	-$ 5,052	-$ 253,571
RSVA-Power Global Adjustment	1588	$ 441,977	$ 16,132	$ 458,109
Recovery of Regulatory Asset Balances	1595	-$ 7,183	-$ 87,009	-$ 94,192
Group 1 Sub total		**-$ 271,364**	**-$ 81,101**	**-$ 352,465**
Group 2 Accounts				
Sub Acct Deferred IFRS Transition Costs	1508	$ 299,035	$ 9,429	$ 308,464
Retail Cost Variance Account	1518	$ 32,409	-$ 1,072	$ 31,337
Retail Cost Variance Account - STR	1548	$ 71,664	$ 13,974	$ 85,638
RSVA - One Time	1582	$ 71,180	$ 11,961	$ 83,141
Other Deferred Credits	2425	-$ 96,053	-$ 2,729	-$ 98,782
HST/OVAT Input Tax Credits (ITCs)	1592	-$ 43,209	$ -	
Group 2 Sub total		**$ 335,026**	**$ 31,563**	**$ 366,589**
Group 1 & Group 2 Total		**$ 63,662**	**-$ 49,538**	**$ 14,124**

Table 2.2 provides the interest rates that have been used to calculate actual and forecasted carrying charges on the accounts in accordance with the methodology approved by the Board in EB-2006-0117 on November 28, 2006.

Table 9.4 - Interest Rates Applied to Deferral and Variance Accounts

Quarter	Interest Rate Utilzed
Q1 2005	7.25%
Q2 2005	7.25%
Q3 2005	7.25%
Q4 2005	7.25%
Q1 2006	7.25%
Q2 2006	4.14%
Q3 2006	4.59%
Q4 2006	4.59%
Q1 2007	4.59%
Q2 2007	4.59%
Q3 2007	4.59%
Q4 2007	5.14%
Q1 2008	5.14%
Q2 2008	4.08%
Q3 2008	3.35%
Q4 2008	3.35%
Q1 2009	2.45%
Q2 2009	1.00%
Q3 2009	0.55%
Q4 2009	0.55%
Q1 2010	0.55%
Q2 2010	0.55%
Q3 2010	0.89%
Q4 2010	1.20%
Q1 2011	1.47%
Q2 2011	1.47%
Q3 2011	1.47%
Q4 2011	1.47%
Q1 2012	1.47%
Q2 2012	1.47%

METHOD AND ACCOUNTS REQUESTED FOR DISPOSITION BY WAY OF A DEFERRAL AND VARIANCE ACCOUNT RATE RIDER

IHDSL is requesting disposition of the variance accounts noted below according to the Report of the Board EB-2009-0046, which states that "at the time of rebasing, all Account balances should be disposed of unless otherwise justified by the distributor or as required by a specific Board decision or guideline.

IHDSL has followed the guidelines in the Report of the Board and requests disposition over a one-year period. IHDSL has provided a continuity schedule of the accounts listed below in Appendix C of this exhibit.

IHDSL is requesting the disposition of the following Group 1 and Group 2 Accounts as reflected in Table 9.5 and 9.6. These amounts are comprised of the audited balances as of December 31, 2011 and the forecasted interest through April 30, 2013.

Table 9.5 Summary of 2013 DVA Dispositions Group 1 & 2 (excluding 1588 GA sub account)

Group 1 Accounts	Account Number		Principal Balance		Interest Balance		Total Claim
LV Variance Account	1550	-$	46,364	$	1,672	-$	44,692
RSVA-Wholesale Market Service Charge	1580	-$	291,192	-$	5,869	-$	297,061
RSVA-Retail Transmission Network	1584	-$	20,724	$	714	-$	20,010
RSVA-Retail Transmission Connection	1586	-$	99,359	-$	1,689	-$	101,048
RSVA-Power (excl Global Adjustment)	1588	-$	248,519	-$	5,052	-$	253,571
Recovery of Regulatory Asset Balances	1595	-$	7,183	-$	87,009	-$	94,192
Sub Acct Deferred IFRS Transition Costs	1508	$	299,035	$	9,429	$	308,464
Retail Cost Variance Account	1518	$	32,409	-$	1,072	$	31,337
Retail Cost Variance Account - STR	1548	$	71,664	$	13,974	$	85,638
RSVA - One Time	1582	$	71,180	$	11,961	$	83,141
Other Deferred Credits	2425	-$	96,053	-$	2,729	-$	98,782
HST/OVAT Input Tax Credits (ITCs)	1592	-$	43,209	$	-	$	-
Group 1 & Group 2 Total		**-$**	**378,315**	**-$**	**65,670**	**-$**	**443,985**

Table 9.6 Global Adjustment Sub Account for Non-RPP

Group 1 Accounts	Account Number	Principal Balance	Interest Balance	Total Claim
RSVA-Power Global Adjustment	1588	$ 441,977	$ 16,132	$ 458,109
Total				**$ 458,109**

Calculation of Rate Riders

Table 9.7 summarizes the variables used to determine the proposed regulatory asset rate rider by rate class for the Group 1 and Group 2 accounts, excluding the Non-RPP rate rider for the 1588 Sub-Account Global Adjustment. The billing determinants are based on the 2013 Test Year forecast load data and calculated for a one-year disposition period.

Table 9.7 Rate Rider Calculation Group 1 & Group 2 Deferral/Variance Account Balances

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1588 sub-account)	Rate Rider for Deferral/Variance Accounts
Residental	kWh	155,528,870	-$ 300,903	- **0.0019**
GS <50	kWh	31,359,068	-$ 60,671	- **0.0019**
GS >50	**kW**	116,345	-$ 77,889	- **0.6695**
Unmetered Scattered Load	kWh	562,039	-$ 1,087	- **0.0019**
Sentinel Lights	**kW**	344	-$ 239	- **0.6946**
Street Lighting	**kW**	4,924	-$ 3,197	- **0.6492**
Total			**-$ 443,985**	

Table 9.8 summarizes the variables used to determine the proposed non-RPP global adjustment rate rider by rate class. The billing determinants are based on the 2013 Test Year forecast load data and calculated for a one-year disposition period.

Table 9.8 Global Adjustment Account Balance

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of RSVA - Power - Sub-	Rate Rider for RSVA - Power -	
Residental	kWh	19,229,800	$ 118,361	**0.0062**	$/kWh
GS <50	kWh	5,070,679	$ 31,211	**0.0062**	$/kWh
GS >50	**kW**	140,528	$ 299,303	**2.1298**	**$/kW**
Unmetered Scattered Load	kWh	38,352	$ 236	**0.0062**	$/kWh
Sentinel Lights	**kW**	35	$ 76	**2.2100**	**$/kW**
Street Lighting	**kW**	4,319	$ 8,921	**2.0655**	**$/kW**
Total			**$ 458,109**		

Stranded Meter Costs

IHDSL is also seeking disposition of its stranded meter costs. IHDSL has continued to record the costs of the stranded meters in Account 1860 and has continued to depreciate these assets over a 25 year period until December 31, 2012. Throughout the smart meter Implementation IHDSL replaced 14,290 conventional meters with smart meters. As of December 31, 2012 the NBV of the stranded meters for IHDSL is $359,195.

Table 9.10: Stranded Asset Values

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006					$ -		$ -
2007					$ -		$ -
2008					$ -		$ -
2009	Actual	$ 1,270,515	$ 1,068,807		$ 201,708		$ 201,708
2010	Actual	$ 426,641	$ 181,320		$ 245,321		$ 245,321
2011	Actual		$ 31,125		-$ 31,125		-$ 31,125
2012	Forecast		$ 42,532		-$ 42,532		-$ 42,532
2013	Forecast		$ 14,177		-$ 14,177		-$ 14,177
as at 12/31/11		$ 1,697,156	$ 1,281,252				
					$ 359,195		$ 359,195

Appendix 2 – Tab S

With respect to the Filing Requirements Schedule App2-S, IHDSL provides the following responses under Scenario A;

Question 1

Stranded meter costs and accumulated depreciation were transferred to account 1555 and continued depreciation. The stranded meters were reported within the regulatory asset classification within the balance sheet.

Question 2

The amount of the pooled residual net book value of the stranded meters as of December 31, 2010 is forecasted to be $447,029.

Question 3

Depreciation has continued since transferring the stranded meter costs to account 1555. The amount of depreciation since the transfer of the stranded meters equals $31,125 for 2011, $42,532 for 2012 and $14,177 equaling $87,834.

Question-3a

No carrying charges were recorded for the stranded meter cost balances in account 1555.

Question-3b

The amount of the pooled residual net book value of the stranded meters as of April 2012 is forecasted to be $359,195. IHDSL is proposing to recover the residual net book value of the stranded meters for a 2 year period for the Residential and GS<50 kW rate classes. IHDSL is proposing to transfer the residual NBV of the stranded meter to a sub account of account 1595 and record the customer recovery to sub DVA account 1595.

Stranded Smart Meter Asset Rate Rider Calculation

IHDSL is requesting recovery of the NBV of the stranded meters for an amount of $359,195. IHDSL proposes to recover this amount through a fixed monthly rider from metered customers in the Residential and GS>50kW rate classes. Utilizing data from the removed meters IHDSL determined the allocation by rate class. The allocation was 78.5% for the Residential rate class and 21.5% for the GS< 50kW rate class. Based on IHDSL's 2013 customer forecast a rate rider of $1.66 per month per Residential customer and $7.06 per month per GS<50kW customer per month would be required to recover these amounts in one year. To reduce customer impact, IHDSL proposes to recover this amount over 2 years at a rate of $0.83 per residential customer and $3.53 per GS<50 kW per month per metered customer in the aforementioned customer classes. Table 9.11 summarizes the calculation of this rate.

Table 9.11 Stranded Meter Rate Rider Calculation

Stranded Meters Calculation:

Capital Cost	$	1,697,156
Accumulated Depreciation (to 31-Dec-2011)	$	1,281,252
2012 Depreciation	$	42,532
2013 Depreciation	$	14,177
Net Book Value:	**$**	**359,195**

Net Book Value Segregated by Rate Class:	**Residential**	**GS <50 kW**	**Total**
	$ 282,074	$ 77,121	**$359,195**
Allocated Weighting Based on Stranded Meters	78.5%	21.5%	**100%**
Number of Metered Customers:	14189	910	**15,099**
Rate Rider to Recover Stranded Meter Costs:	**$ 0.83**	**$ 3.53**	
Recovery period (years):	**2**	**2**	

GREEN ENERGY PLAN – FUNDING ADDER

IHDSL has submitted a basic Green Energy Plan to the OPA and has provided a copy in Appendix C. The OPA provided a Letter of Comment which has been provided in Appendix D.

As part of its GEA Plan, IHDSL has estimated the following capital and OM&A expenditures for 2013, 2014 and 2015.

IHDSL requests a funding adder to be included in its rates of $0.5233 (average of the 3 years) per Residential, GS>50kW and GS<50kW -4,999kW per month. The finding adder calculations were based on the Incremental Revenue Requirement Calculation provided below. An electronic version of this model has been provided as part of this application.

GEA Incremental Revenue Requirement Calculation

	2013		2014		2015		
Net Fixed Assets		$ 710,000		$260,000		$ 261,000	
OM&A	$ 75,000		$ 77,000		$ 80,000		
WCA	13.0%	$ 9,750	13.0%	$ 10,010	13.0%	$ 10,400	
Rate Base		$ 719,750		$270,010		$ 271,400	
Deemed ST Debt	4%	$ 28,790	4%	$ 10,800	4%	$ 10,856	
Deemed LT Debt	56%	$ 403,060	56%	$151,206	56%	$ 151,984	
Deemed Equity	40%	$ 287,900	40%	$108,004	40%	$ 108,560	
ST Interest	2.08%	$ 599	2.08%	$ 225	2.08%	$ 226	
LT Interest	5.11%	$ 20,596	5.11%	$ 7,727	5.11%	$ 7,766	
ROE	8.01%	$ 23,061	8.01%	$ 8,651	8.01%	$ 8,696	
		$ 44,256		$ 16,602		$ 16,688	
OM&A		**$ 75,000**		**$ 77,000**		**$ 80,000**	
Amortization		$ 25,278		$ 53,333		$ 58,889	
Grossed-up PILs		-$ 2,371		-$ 17,161		-$ 15,689	
Revenue Requirement		$ 142,163		$129,774		$ 139,887	
Direct Benefit							
OM&A		$ 75,000		$ 77,000		$ 80,000	
Capital		$ 67,163		$ 52,774		$ 59,887	
Direct Benefit % on capital		0.00%		55.25%		41.00%	
Direct Benefit on capital		$ -		$ 29,156		$ 24,552	
Total Direct Benefit		$ 75,000		$106,156		$ 104,552	
Total # of Customers (Residential, GS<>50)		15,165		15,165		15,165	
GEA Rate Adder		$ 0.4121		$ 0.5833		$ 0.5745	3 year average $ 0.5233
Provincial Rate Protection		$ 67,163		$ 23,619		$ 35,335	
Monthly Adder Amount Paid by IESO		$ 5,597		$ 1,968		$ 2,945	

IHDSL has divided its expected expenditures into two categories, Renewable Enabling Improvements and Feeder Automation Projects, and has estimated the amortization for each category based on the weighted average depreciation rates for the type of expenditures anticipated in 2013, us ing rates established under MIFRS. R enewable Improvements are depreciated over 45 years and Feeder Automation over 10 years. 6% of Renewable Enabling Improvements Enabling expenses have been designated as Direct Benefit, with the balance assigned to Provincial Rate Protection. Table 6.1 Renewable Capital Investment, contains these details.

Table 6.1 Renewable Capital Investment

Renewable Connections Capital - Renewable Enabling Improvements				
RECLOSER		**2013**	**2014**	**2015**
Opening Capital Investment		$ -	$ 250,000	$ 500,000
Capital Investment		$ 250,000	$ 250,000	$ 250,000
Closing Capital Investment		$ 250,000	$ 500,000	$ 750,000
Opening Accumulated Amortization		$ -	$ 2,778	$ 11,111
Amortization Year One	45 Years	$ 2,778	$ 2,778	$ 2,778
Amortization Thereafter		$ -	$ 5,556	$ 11,111
Closing Accumulated Amortization		$ 2,778	$ 11,111	$ 25,000
Opening Net Fixed Assets		$ -	$ 247,222	$ 488,889
Closing Net Fixed Assets		$ 247,222	$ 488,889	$ 725,000
Average Net Fixed Assets		$ 123,611	$ 368,056	$ 606,944
Feeder Automation Projects				
SCADA		**2013**	**2014**	**2014**
Opening Capital Investment		$ -	$ 450,000	$ 450,000
Capital Investment		$ 450,000	$ -	$ -
Closing Capital Investment		$ 450,000	$ 450,000	$ 450,000
Opening Accumulated Amortization		$ -	$ 22,500	$ 67,500
Amortization Year One	10 years	$ 22,500	$ -	$ -
Amortization Thereafter		$ -	$ 45,000	$ 45,000
Closing Accumulated Amortization		$ 22,500	$ 67,500	$ 112,500
Opening Net Fixed Assets		$ -	$ 427,500	$ 382,500
Closing Net Fixed Assets		$ 427,500	$ 382,500	$ 337,500
Average Net Fixed Assets		$ 213,750	$ 405,000	$ 360,000

Average Net Fixed Assets	**Direct Benefit %**	**2012**	**2013**	**2014**
Renewable Connections Capital - Expansions	17%	$ -	$ -	$ -
Renewable Connections Capital - Renewable Enabling Improvements	6%	$ 123,611	$ 368,056	$ 606,944
Feeder Automation Projects	100%	$ -	$ 405,000	$ 360,000
		$ 123,611	$ 773,056	$ 966,944
Direct Benefit		$ 7,417	$ 427,083	$ 396,417
Weighted Average Direct Benefit %		0.00%	55.25%	41.00%

Using these capital investment estimates IHDSL has estimated the incremental revenue requirement as shown below in Table 6.2. The incremental revenue calculation has been adjusted for PILS (Table 6.3). IHDSL proposes to recover $ 285,708 o f this amount from its customers as a direct benefit thru a fixed monthly funding adder of $0.5233 per customer. IHDSL proposes to recover the remaining through Provincial Rate Protection and requests a funding adder from the IESO for $3,503 per month.

When these costs are finalized at the end of 2015 IHDSL will come forward with a cost recovery application including a true-up rider and revenue collection rider to collect/disperse any variances from these amounts.

Table 6.2 Incremental Revenue Requirement & Funding Adder Calculation

Direct Benefit				
OM&A	$ 75,000	$ 77,000	$ 80,000	
Capital	$ 67,163	$ 52,774	$ 59,887	
Direct Benefit % on capital	0.00%	55.25%	41.00%	**Total for Recovery**
Direct Benefit on capital	$ -	$ 29,156	$ 24,552	**2013-2015**
Total Direct Benefit	$ 75,000	$106,156	$ 104,552	$ 285,708
Total # of Customers (Residential, GS<>50)	15,165	15,165	15,165	
				3 year average
GEA Rate Adder - Monthly Fixed Charge	$ 0.4121	$ 0.5833	$ 0.5745	$ 0.5233
Provincial Rate Protection	$ 67,163	$ 23,619	$ 35,335	$ 126,117
Monthly Adder Amount Paid by IESO	$ 5,597	$ 1,968	$ 2,945	$ 3,503

Table 6.3 PILS Calculation

PILs Calculation			
	2013	2014	2015
INCOME TAX			
Net Income	$ 23,061	$ 8,651	$ 8,696
Amortization	$ 25,278	$ 53,333	$ 58,889
CCA	-$ 55,000	-$ 110,200	-$ 111,664
Change in taxable income	-$ 6,661	-$ 48,216	-$ 44,079
Tax Rate	26.25%	26.25%	26.25%
Income Taxes Payable	-$ 1,749	-$ 12,657	-$ 11,571
ONTARIO CAPITAL TAX			
Closing Net Fixed Assets	$ 247,222	$ 488,889	$ 725,000
Less: Exemption	$ -	$ -	$ -
Deemed Taxable Capital	$ 247,222	$ 488,889	$ 725,000
Ontario Capital Tax Rate			
Net Amount (Taxable Capital x Rate)	$ -	$ -	$ -
Gross Up			
	PILs Payable	PILs Payable	PILs Payable
Change in Income Taxes Payable	-$ 1,748.63	-$ 12,656.58	-$ 11,570.86
Change in OCT	$ -	$ -	$ -
PIL's	-$ 1,748.63	-$ 12,656.58	-$ 11,570.86
	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs
Change in Income Taxes Payable	-$ 2,371.02	-$ 17,161.47	-$ 15,689.30
Change in OCT	$ -	$ -	$ -
PIL's	**-$ 2,371.02**	**-$ 17,161.47**	**-$ 15,689.30**

APPENDIX A

2012 REVISED EDVVAR MODEL FOR NON-RPP GLOBAL ADJUSTMENT AMOUNT

Rate Rider Calculation for RSVA - Power - Sub-account - Global Adjustment

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of RSVA - Power - Sub-	Rate Rider for RSVA - Power -	
Residental	kWh	19,229,800	$ 118,361	**0.0062**	$/kWh
GS <50	kWh	5,070,679	$ 31,211	**0.0062**	$/kWh
GS >50	kW	140,528	$ 299,303	**2.1298**	$/kW
Unmetered Scattered Load	kWh	38,352	$ 236	**0.0062**	$/kWh
Sentinel Lights	kW	35	$ 76	**2.2100**	$/kW
Street Lighting	kW	4,319	$ 8,921	**2.0655**	$/kW
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
Total			**$ 458,109**		

APPENDIX B

2012 REVISED EDVVAR MODEL EXCLUDING NON-RPP GLOBAL ADJUSTMENT AMOUNT

Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.)

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1588 sub-account)	Rate Rider for Deferral/Variance Accounts	
Residental	kWh	155,528,870	-$ 300,903	- **0.0019**	$/kWh
GS <50	kWh	31,359,068	-$ 60,671	- **0.0019**	$/kWh
GS >50	**kW**	116,345	-$ 77,889	- **0.6695**	**$/kW**
Unmetered Scattered Load	kWh	562,039	-$ 1,087	- **0.0019**	$/kWh
Sentinel Lights	**kW**	344	-$ 239	- **0.6946**	**$/kW**
Street Lighting	**kW**	4,924	-$ 3,197	- **0.6492**	**$/kW**
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
Total			**-$ 443,985**		