LAKEFRONT UTILITIES INC. (LUI)

APPLICATION FOR APPROVAL OF ELECTRICITY DISTRIBUTION RATES

EFFECTIVE MAY 1, 2012

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ADMINISTRATION

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

AND IN THE MATTER OF an Application by Lakefront Utilities Inc. 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, 2012.

Title of Proceeding:	An application by Lakefront Utilities Inc. for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2012.
Applicant's Name:	Lakefront Utilities Inc.
Applicant's Address for Service:	207 Division Street Cobourg, ON K9A 3P6 Attention: Jennifer Theoret Telephone: 905-372-2193 Ext. 5255
Applicant's Counsel:	Borden Ladner Gervais LLP Suite 4100 40 King Street West Toronto ON M5H 3Y4

APPLICATION

Introduction

(a) The Applicant is Lakefront Utilities Inc. (referred to in this Application as the "Applicant" or "LUI"). The Applicant is a corporation incorporated pursuant to the Ontario *Business Corporations Act* with its head office in the Town of Cobourg. The Applicant owns and operates the electrical distribution systems in Cobourg and Colborne (Cramahe Township) and carries on the business of distributing electricity to approximately 9,800 residential and business customers within its service territory.

(b) 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, 2012. A list of requested approvals is set out in Exhibit 1.

(c) Except where specifically identified in the Application, the Applicant followed Chapter 2 of the OEB's Filing Requirements for Transmission and Distribution Applications dated June 22, 2011 (the "Filing Requirements") in order to prepare this application.

(d) The Applicant's current rates will result in actual Return on Equity in 2011 and 2012 well below levels currently approved by the OEB. The increased rates are required to:

1. Continue to promote and practice excellence in safety;
2. Commitment to excellence in customer service level;
3. Maintain capital investment levels in infrastructure as well as future requirements to ensure a safe, reliable distribution system;
4. Continue with training and development programs for all staff, needed to meet LUI's future staffing requirements and prepare for succession planning;
5. Ensure streamlined effectiveness, all regulatory compliance, promote conservation programs along with the introduction of smart meters, and implement reporting changes resulting from the adoption of International Financial Reporting Standards;
6. To provide a reasonable rate of return to the Shareholder.

Background

LUI is focused on providing excellent customer service and provides educational information through various sources to its customers. LUI also operates and makes decisions based from a sound business perspective. It has a progressive Board of Directors that provides oversight in not only providing what is best for LUI's customers, it also ensures that it is done using sound business analysis and practices. LUI is always striving to contain its costs where possible and it is aware that all costs are ultimately borne by its customers.

LUI has undergone significant financial challenges since market opening but has continued to distribute electricity safely and reliably to its customers. We have an exemplary record of providing high standards of service and reliability, with a safety record of over 380,000 hours of no loss time accident as of the timing of the rate application.

We believe we have made positive efforts towards maintaining high levels of efficiencies in a setting of increasing costs. Despite these challenges, LUI is always seeking ways to improve efficiencies in our business operations by evaluating strategies and policies which may be implemented to ensure that present and forthcoming challenges are met effectively. Some of those strategies include pooling resources and building alliances with organizations such as the Cornerstone Hydro Electric Concept ("CHEC") group. LUI has demonstrated the ability to adapt to constant changes in the electricity environment.

Among all of the important factors affecting the efficiency of LUI is the scale of operations and the scope of activities, and the high value impact of electricity to the economy and to the society which mandates that LUI's exemplary record must continue to be maintained. However, we continue to face many challenges:

a) **Infrastructure investment**: aging infrastructure needs to be refurbished or replaced on an ongoing basis and new investment is required to meet system growth and expansion. It is essential that

associated programs are conducted in a timely fashion to ensure service quality and to minimize longer term costs. Undue delay of such programs may result in greater overall costs to customers as well as rate shock if pent-up capital needs are subsequently met on an accelerated basis.

b) **New and emerging technologies**: **Smart meters** have been installed across our service territory and much of the Province. In order to fully realize the value inherent in this investment, which was mandated by the Province, LUI will need to continue to develop programs such as outage management, voltage drop monitoring and theft detection, which make effective use of this technology. Other innovative technologies will require ongoing resource commitments in order to ensure that they are incorporated in a cost effective manner. In time, these developments can facilitate the incorporation of distributed generation, enhance load management and even provide for real-time customer response to system requirements.

c) **Conservation and Demand Management**: All electric utilities, including LUI, are required to meet conservation and demand management targets set by the Ontario Energy Board. For LUI this has resulted in an expansion of accounting and administrative tasks and responsibilities;

d) **Distributed generation**: The integration of distributed generation facilities has acquired an ever increasing importance particularly where substantial changes are required for the operation and design of distribution systems. Current incentives for renewable energy projects have led to an abundance of applications, particularly for providers of small scale solar generation.

e) **Costs**: Ontario electricity prices are projected to grow by 46% in the upcoming five years and 100% in the long term. A large portion of the increase is attributable to renewable energy programs. Though these rate increases are not principally attributable to distribution functions, they put pressure on cost structures throughout the industry and can affect regulated price increases and the internal decision-making at utilities such as LUI;

f) **Regulation and Government Policy**: Recent legislative and policy initiatives have increased political and regulatory uncertainty. The Green Energy Act has created new obligations for LUI, such as the requirement to connect renewable resources. The increased direct role of the Government, through the issuance of directives, is also likely to increase the uncertainty of the policy environment within which LUI operates. Regulatory burden has also increased over the last decade. Rate Applications have become much more time consuming, complex and expensive than they were a decade ago;

g) **Shareholders Objectives**: LUI needs to ensure that it is meeting the objectives set by its shareholders, including financial performance targets.

LUI, similar to many LDCs, is facing an aging workforce and looming retirements. LUI works diligently to maintain its level of staff members and is prudently preparing for the future by hiring apprentices and trainees. Apprenticeship training periods are four to five years, thus, planning is imperative to have trainees part way through their apprenticeship in advance of a Journeyperson retiring.

More than two decades ago, LUI developed a long term program of voltage conversion to convert its 4 KV systems to 27.6 KV and we have steadily stayed on this path. LUI has increased its rate of conversion to higher distribution voltage levels in the past few years, in order to provide more reliable service to its customers in a more cost efficient manner.

LUI will continue investments in its distribution system to not only meet the demands of growth and new technological advancements but also to improve the reliability and efficiency that would have, if left unaddressed, certainly decline.

Including these expenditures, (which are relative to other peers, comparator and cohort's measured expenses and costs), LUI submits that our cost performance is reasonable, adequate and prudent. LUI's request for the proposed adjusted distribution rates is necessary to meet LUI's Market Based Rate of Return while continuing to provide dependable service to our customers.

Proposed Distribution Rates and Other Charges

(a) The Schedule of Rates and Charges proposed in this Application is identified in Appendix A attached to this application and in Exhibit 8, and the material being filed in support of this Application sets out LUI's approach to its distribution rates and charges.

Proposed Effective Date of Rate Order

(a) LUI requests that the OEB make its Rate Order effective May 1, 2012 in accordance with the Filing Requirements.

The Proposed Distribution Rates and Other Charges are Just and Reasonable

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

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

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

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

the other service charges with exception of the temporary service charges proposed by LUI 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

(b) LUI applies for an Order or Orders approving the proposed distribution rates and other charges set out in Exhibit 1, Appendix A to this Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2012, or as soon as possible thereafter; and

Form of Hearing Requested

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

DATED at Cobourg, Ontario, this 14th day of October 2011.

All of which is respectfully submitted,

Jennifer Theoret

LAKEFRONT UTILITIES INC.
Jennifer Theoret, CA
Director of Finance and Compliance

CONTACT INFORMATION

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APPENDIX A SCHEDULE OF PROPOSED RATES AND CHARGES

Customer Class	Item Description	Unit	Rate ($)
Residential			
	Monthly Service Charge	per month	12.25
	Distribution Volumetric Rate	per kWh	0.0177
	Low Voltage Rider	per kWh	0.0013
	LRAM and SSM Rate Rider	per kWh	0.0002
	Stranded meter Rate Rider	per month	2.37
	Smart Meter Rate Rider	per month	0.05
	Deferral and Variance Account Rider	per kWh	(0.0005)
GS < 50 kW			
	Monthly Service Charge	per month	28.02
	Distribution Volumetric Rate	per kWh	0.0101
	Low Voltage Rider	per kWh	0.0012
	LRAM and SSM Rate Rider	per kWh	0.0002
	Stranded Meter Rate Rider	per month	2.37
	Smart Meter Rate Rider	per month	0.05
	Deferral and Variance Account Rider	per kWh	(0.0006)
GS 50-2999			
	Monthly Service Charge	per month	181.20
	Distribution Volumetric Rate	per kW	3.3764
	Low Voltage Rider	per kW	0.4778
	LRAM and SSM Rate Rider	per kWh	0.0069
	Stranded Meter Rate Rider	per month	2.37
	Smart Meter Rate Rider	per month	0.05
	Deferral and Variance Account Rider	per kW	(0.2750)
GS 3000 - 4999			
	Monthly Service Charge	per month	2,617.84
	Distribution Volumetric Rate	per kW	1.2323
	Low Voltage Rider	per kW	0.5635
	LRAM and SSM Rate Rider	per kW	0.0149
	Stranded Meter Rate Rider	per month	2.37
	Smart Meter Rate Rider	per month	0.05
	Deferral and Variance Account Rider	per kW	(0.2836)
Sentinel Lights			
	Monthly Service Charge	per month	4.30
	Distribution Volumetric Rate	per kW	10.5767
	Low Voltage Rider	per kW	0.3771
	LRAM and SSM Rate Rider	per kW	0.0000
	Deferral and Variance Account Rider	per kW	0.1763
Street Lighting			
	Monthly Service Charge	per month	3.26
	Distribution Volumetric Rate	per kW	20.6590
	Low Voltage Rider	per kW	0.3694
	LRAM and SSM Rate Rider	per kW	0.0000
	Deferral and Variance Account Rider	per kW	1.1889
USL			
	Monthly Service Charge	per month	15.79
	Distribution Volumetric Rate	per kWh	0.0412
	Low Voltage Rider	per kWh	0.0015
	LRAM and SSM Rate Rider	per kWh	0.0000
	Deferral and Variance Account Rider	per kWh	0.0000

Item Description	Calculation Basis	Rate ($)
Arrears certificate	Standard	15.00
Statement of account	Standard	15.00
Pulling post dated cheques	Standard	15.00
Request for other billing information	Standard	15.00
Easement letter	Standard	15.00
Income tax letter	Standard	15.00
Credit reference/credit check (plus credit agency costs)	Standard	15.00
Returned cheque charge (plus bank charges)	Standard	15.00
Legal letter charge	Standard	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	Standard	30.00
Special meter reads	Standard	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	Standard	30.00
Collection of account charge - no disconnection	Standard	30.00
Collection of account charge - no disconnection - after regular hours	Standard	165.00
Disconnect/Reconnect at meter - during regular hours	Standard	65.00
Disconnect/Reconnect at meter - after regular hours	Standard	185.00
Disconnect/Reconnect at pole - during regular hours	Standard	185.00
Disconnect/Reconnect at pole - after regular hours	Standard	415.00
Install/Remove load control device - during regular hours	Standard	65.00
Install/Remove load control device - after regular hours	Standard	185.00
Service call - customer-owned equipment	Standard	30.00
Service call - after regular hours	Standard	165.00
Temporary service install & remove - overhead - no transformer	Standard	500.00
Temporary service install & remove - underground - no transformer	Standard	300.00
Temporary service install & remove - overhead - with transformer	Standard	1,000.00
Specific Charge for Access to the Power Poles $/pole/year	Standard	22.35
Interval Meter Load Management Tool Charge $/month	Standard	110.00
Service charge for onsite interrogation of interval meter due to customer phone line failure -required weekly until line repaired	Standard	60.00

SPECIFIC APPROVALS REQUESTED

In this proceeding, LUI is requesting the following approvals:

Approval to charge rates effective May 1, 2012 to recover a service revenue requirement of $ 5,131,204 which includes a revenue deficiency of $ 743,941 as set out in Exhibit 1 and Exhibit 5. The schedule of proposed rates is set out in Exhibit 1 and Exhibit 8;

Approval of the proposed loss factor as set out in Exhibit 8;

Approval of low voltage rates to be included in the standard distribution rates as proposed and described in Exhibit 8;

Approval to continue to charge Retail Transmission-Network Service, Retail Transmission-Connection, and Wholesale Market and Rural Rate Protection Charges approved in the OEB Decision and Order in the matter of LUI's 2011 Distribution Rates (EB-2010-0095) subject to the Guideline Electricity Distribution Retail Transmission Service (G-2008-0001) issued October 22, 2008, Revision 1.0 issued July 22, 2010;

Approval to continue the Specific Service Charges and Transformer Allowance approved in the OEB Decision and Order in the matter of LUI's 2011 Distribution Rates (EB-2010-0095) and;

Approval of new Specific Service Charge, Service Charge for on-site Interrogation of Interval Meter Due to Customer Phone Line Failure, as outlined in Exhibit 3;

Approval of the proposed Smart Meter Recovery Rate Rider as set out in Exhibit 9 and based on the OEB's Guideline G-2008-00037 – Smart Meter Funding and Cost Recovery, issued October 2, 2008;

Approval for a smart meter cost recovery rate rider for the difference between the smart meter adder collected from May 1, 2006 until April 30, 2012 and the revenue requirement related to these smart meters up to December 31, 2011, through a rider of $0.05 per month per metered customer, for one year;

Approval for a stranded meter rate rider of $2.37 per month per metered customer, for one year to recover the net book value of $ $ 279,651 for stranded meters as at December 31, 2010;

Approval to include smart meter capital deployed as of December 31, 2011 in the 2012 rate base that supports the 2012 revenue requirement and distribution rates which is the subject of this rate application;

Approval to include smart meter operation and maintenance expenses in the 2012 revenue requirement associated with the smart meters deployed;

Approval to discontinue the Smart Meter rate adder;

Approval to realign the Revenue to Cost ratios as detailed in Exhibit 7;

Approval to recover proposed Lost Revenue Adjustment Mechanism ("LRAM") amounts based on a volumetric rate rider over a period of one year period commencing on May 1, 2012, using the method of recovery described in Exhibit 10;

Approval of the Basic Green Energy Plan as set out in Exhibit 2;

In the event the OEB is unable to provide a Decision and Order on the Application for implementation of rate by LUI as of May 1, 2012, LUI requests that the OEB issue an Interim Order

approving the proposed distribution rates and other charges, effective May 1, 2012 which may be subject to adjustment based on its final Decision and Order.

Approval to dispose of the following Deferral and Variance Account Balances as at April 30, 2012 over a one-year period using the method of recovery described in Exhibit 9:

1508	Other Regulatory Assets - Other
1518	Retail Cost Variance Account
1548	Retail Cost Variance Account (STR)
1550	Low Voltage Variance
1580	Wholesale Market Service Charge
1582	OneTime WMS Account
1584	Retail Transmission Network Variance
1586	Retail Transmission Connection Variance
1588	Power Variance
1588	Power Variance - Sub Account GA
1590	Regulatory Asset Recovery
1595	Disposition and Recovery of Regulatory Balances
1582	One-Time Charges Variance
1562	PILS

PROPOSED ISSUES LIST

1. GENERAL (Exhibit 1)

- Are the Applicant's overall economic and business planning assumptions for the Test Year appropriate?
- Is service quality, based on the Board specified performance indicators, acceptable?
- Is the proposed revenue requirement appropriate?

LUI is committed to improving the economic and environmental sustainability of the community served. We continue to work with our shareholder on projects for the benefit of the community. Improvements to our infrastructure remained a priority as we continue with a number of upgrades to our electrical systems.

While LUI currently tracks and reports on service quality indicators to the OEB, work will continue throughout 2012 to ensure even more accurate and consistent reporting. LUI consistently exceeded the OEB's service quality indicators and is committed to maintaining its performance at levels equal to or above the OEB's standards in 2011 and 2012.

LUI's proposed revenue requirement in the amount of $5,131,204 includes a revenue deficiency of $743,940 based on present rates. By comparison, the OEB approved revenue requirement from LUI's 2008 Cost of Service, was approximately $4.32 million. This represents an average increase of approximately 3.5%.

The estimated average distribution revenue per customer in 2008 is $474 which is well below LUI's cohort and industry average. LUI is forecasting the 2012 average distribution revenue per customer will be approximately $522 which remains at the low end of LUI's cohort as reported in the OEB's *Yearbook of Electricity Distributors*.

LUI believes the average revenue calculations are underpinned by fair and reasonable rates now an in 2012.

2. RATE BASE (Exhibit 2)

- Are the Applicant's asset planning assumptions (e.g. asset condition, economic conditions, etc.) appropriate?
- Is the Applicant's capitalization and depreciation policy appropriate?
- Are the capital expenditures appropriate?
- Are the in-service dates accurate for projects closed prior to the Test Year and are they appropriate for proposed projects?
- Is the working capital allowance for the test year appropriate?
- Is the proposed rate base for the test year appropriate?
- Is the accounting for smart meters in rate base appropriate?
- Is the accounting for stranded meters appropriate?
- Is the basic Green Energy Plan appropriate?

LUI's distribution service territory consists of two geographically separated municipalities made up of the town of Cobourg and the village of Colborne. The distribution plant presently consists of a sub-transmission network (44kV), two municipal sub-stations at 27.6kV and six municipal sub-stations at 4.16kV.

LUI continues to expand and reinforce its distribution system in order to meet the demand of all customers in its service territory. Expenditures are also being made to meet regulations set out by the Ministry of Energy, the OEB, and the IESO including facilitating DG connections, voltage conversion works, load transfers and primary metering points.

LUI's capital and operating programs have a history of adapting based on asset inspection findings and in keeping with industry best practices. LUI maintains very good inspection and maintenance practices.

LUI annually prepares a three year capital expenditure forecast and plan. Applying prudence in its 2012 plan in consideration of a "smoothing effect" and being cognizant of the 4-year capital "leveling" period in a COS Application. Some of the items in LUI's 2012 plan are:

- Convert the 4kV to 27.6kV voltages to improve efficiency, replace end-of-life infrastructure and increase circuit capacity on existing overhead lines. Most of this infrastructure dates back to the 1960's and 1970's.
- Initiate the studies in 2011 to start construction of a new 27.6 kV MS substation.
- Obtain permits and start construction of a new Administrative Building and Service Centre (by expanding our garage facility in 2012). This new building is needed to improve efficiencies, consolidate inventory in one location, improve staff working conditions and meet support facility needs.
- Maintain investments in Information Technology and Other Equipment to improve efficiencies and continue to meet the servicing needs of our customers.
- Planned replacements of end of life transportation fleet to ensure safety at all times.
- The 2012 Capital Expenditures have been adjusted by the impact of the introduction of the Harmonized Sales Tax (HST), and as such, no further adjustments are necessary. The 2011 Capital Expenditures have been adjusted.
- The rate base expenditures and amortization have been prepared for the Test Year in the MIFRS format.

3. LOADS, CUSTOMERS - THROUGHPUT REVENUE (Exhibit 3)

- Is the load forecast methodology including weather normalization appropriate?
- Are the proposed customers/connections and load forecasts (both kWh and kW) for the test year appropriate?
- Is CDM appropriately reflected in the load forecast?
- Are the proposed revenue offsets appropriate?

LUI's service area has been an area of steady growth at approximately 1.5% per year, until recently, due to the current economic downturn that has affected all sectors of the economy, and conservation measures. The load forecast model and Operating Revenue calculations are included in Exhibit 3.

4. OPERATING COSTS (Exhibit 4)

- Is the overall OM&A forecast for the test year appropriate?
- Are the methodologies used to allocate shared services and other costs appropriate?
- Is the proposed level of depreciation/amortization expense for the test year appropriate?
- Are the 2012 compensation costs and employee levels appropriate?
- Is the test year forecast of PILs appropriate?

The proposed OM&A expenditures **including taxes, depreciation, amortization, and interest expenses** are estimated to be approximately $ **4,424,412**. The rate increase is attributable principally to labour and benefit costs attributed to a number of factors including; increased "overhead" required to implement and maintain regulatory compliance and administer a broad range of initiatives including, among others, those related to smart meters, time of use billing and changes made to the Distribution

System Code and Retail Settlement Code, combined with additional staff to support an aging workforce and succession planning. These regulatory initiatives and employee demographics are placing additional challenges on utilities in relation to the maintenance of effective and cost efficient operations.

The operating costs presented, represents the annual expenditures required to sustain LUI's distribution operations. LUI follows the OEB's Accounting Procedures Handbook (the "APH") in distinguishing work performed between operations and maintenance. A summary of LUI 's operating costs for 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year and the 2012 Test Year in accordance with the Filing Requirements, is provided in the table below:

Summary of OM&A Expenses						
Description	**2008 Board Approved**	**2008 Actual**	**2009 Actual**	**2010 Actual**	**2011 Bridge Year**	**2012 Test Year**
Operations	$ 620,871	$ 617,177	$ 505,675	$ 415,821	$ 579,609	$ 879,396
Maintenance	$ 104,107	$ 77,337	$ 139,615	$ 225,312	$ 306,219	$ 391,786
Billing &Collecting	$ 428,844	$ 440,285	$ 407,715	$ 425,479	$ 501,542	$ 500,298
Community Relations	$ 19,767	$ 8,053	-$ 4,705	$ 13,355	$ 13,927	$ 14,345
Administrative & General Expense	$ 921,831	$ 741,765	$ 806,924	$ 1,019,724	$ 1,047,829	$ 1,281,489
Total OMN&A	**$ 2,095,420**	**$ 1,884,617**	**$ 1,855,224**	**$ 2,099,690**	**$ 2,449,126**	**$ 3,067,314**
Year by Year Increase		-0.02	-1.58%	11.64%	14.27%	20.15%
Compound Annual Growth Rate from 2008 Approved						10%
Compound Annual Growth Rate from 2008 Actual						13%
Inflation Rate Canada CPI		2.4%	0.3%	1.8%	3.0%	3.0%

OM&A costs in the table above represents LUI's integrated set of asset maintenance and customer service activity 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 costs to provide services to customers connected to LUI'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 2012 Test Year are the result of a business planning and work prioritization process that ensures that the most appropriate, cost effective solutions are put in place. LUI strives to make sound and efficient business decisions while maintaining perspective for opportunities in the future.

LUI's estimated average OM&A cost per customer in 2010 is $224 as calculated using the reported OEB's Operating, Maintenance, Administrative Expenses and reported customer figures from the 2010 published *Yearbook of Electricity Distribut*ors provided below, which is one of the lowest when compared with other members of comparable populations served in LUI's cohort. The average for LUI's top 20 cohort being $189 and the industry average of $267. LUI is ranked third most efficient utility in the utility PEG *Sensitivity Analysis on Efficiency Ranking and Cohorts for the 2009 Rate Year,* and being ranked third in efficiency places, LUI is in the top cohort of twenty utilities.

As the distribution system expands and ages, however, it is reasonable to expect that additional costs will be incurred to maintain the additional assets. Likewise, additional investments in new distribution system infrastructure and facilities increases amortization expense. As previously mentioned, LUI strives to maintain the appropriate employee complement; however, as demonstrated in sections of the application, the effect of an aging workforce, long training or apprenticeship periods, and the increased regulatory environment has culminated with increases in staff requirements. Apprenticeships for Powerline Workers and System Control Operators occur over a four year period, training periods for Stations Protection and Control Technician occur over a six year period and training periods for Engineering Technologist/Technician occur over a five year period.

LUI is experiencing what others in the industry are experiencing, an aging workforce and a high volume of retirements in the foreseeable future. LUI will be experiencing in 2012 and 2013, from management's discussions with staff, employees exercising their option to retire earlier than age 65, necessitating the need to increase its number of Powerline Worker apprentices. In addition, increased requirements for regulatory requirements (MDM/R, expense in Smart Meter Deferral Account 1556), and Programming and Reporting needs, have increased LUI's staffing compliment.

5. COST OF CAPITAL AND RATE OF RETURN (Exhibit 5)

- Is the proposed capital structure appropriate?

- Is the cost of debt appropriate?

- Is the proposed return on equity appropriate?

LUI completed its transition to a capital structure of 60% debt and 40% equity through its 2010 electricity distribution rate application. LUI plans to maintain its current capital structure and has prepared this rate application with a deemed capital structure of 56% Long Term Debt, 4% Short Term Debt, and 40% Equity to comply with the Report of the Board on the Cost of Capital for Ontario Regulated Utilities, March 3, 2011.

LUI has assumed a return on equity of 9.58% consistent with the Cost of Capital Parameter Updates for 2011 Cost of Service Applications issued by the OEB on February 24, 2010. LUI understands the OEB will be finalizing the return on equity for 2011 rates based on January 2012 market interest rate information.

LUI will hold a mortgage with TD Canada Trust commencing in 2012 which will provide the long-term financing for the construction of its new substation that started in 2011 and new Administration building addition which will be in service 2012.

LUI is requesting a return on Short Term Debt for the 2012 Test year of 2.46% in accordance with the Cost of Capital Parameter Updates for 2011 Cost of Service Applications issued by the OEB on February 24, 2011. LUI understands that the OEB will be finalizing the return on short term debt for 2012 rates based on January 2012 market interest rate information. LUI's use of a Return on Short Term Debt of 2.46% is without prejudice to any revised ROE that may be adopted by the OEB in early 2012.

6. CALCULATION OF REVENUE DEFICIENCY OR SURPLUS (Exhibit 6)

- Is the calculation of Revenue Deficiency accurate?

LUI requested service revenue requirement for 2012 in the amount of $ 5,131,204 which includes the recovery of its costs to provide distribution services and its' permitted Return on Equity ("ROE"). When

forecasted energy and demand levels for 2012 are considered, LUI estimates that its present rates will produce a deficiency in Gross Distribution Revenue of $ 743,941 for the 2012 Test Year. Should this revenue deficiency continue, LUI will not be able to sustain the current capital investment, staffing requirements and maintenance required to ensure a safe and reliable distribution system.

7. COST ALLOCATION (Exhibit 7)

- Is the Applicant's cost allocation appropriate?
- Are the proposed revenue-to-cost ratios appropriate?

LUI notes that for its Residential, General Service <50 kW, Street Lighting and Unmetered Scattered Load (USL) rate classes, the current revenue to cost ratio of each rate class is within the applicable threshold defined by the OEB in the November 28, 2007, Report on Application of Cost Allocation for Electricity Distributors.

The GS 50 - 2,999 kW, Sentinel Lighting and GS 3,000 - 4,999 kW rate classes were not in the Board's applicable threshold and as a result, adjustments have been made in this Application to bring all rate classes within the allowed ranges of the revenue to cost ratios. The exception will be the GS 3,000 – 4,999 kW class, which LUI is proposing to move 10 points incrementally per year over 4 years to reach the Board's applicable threshold by 2015.

8. RATE DESIGN (Exhibit 8)

- Are the customer charges and the fixed-variable splits for each class appropriate?
- Are the proposed Retail Transmission Service Rates appropriate?
- Are the proposed loss factors appropriate?
- Is the Applicant's proposed Tariff of Rates and Charges appropriate?
- Is the Applicant's rate mitigation plan appropriate?

In preparing this application, LUI has considered the impact on its customers, with the goal of minimizing those impacts. Customer impacts including percentage average Total Bill Impact are set out in Appendix A Table of Rate and Bill Impacts in Exhibit 8. Embedded in this monthly bill impact is the effect of revised distribution rates (monthly service charge and volumetric rate), Smart Meter Funding Adder at its existing level, revised Loss Factors, LRAM rate rider and Deferral and Variance Account Rate Rider to dispose of the balances in the Deferral and Variance accounts requested in this Application.

9. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit 9)

- Are the account balances, cost allocation methodology and disposition plan appropriate?

LUI is in a credit position in various Deferral and Variance accounts.

LUI is requesting the disposition of the amounts specified in Exhibit 9 over a four year period, via a rate rider, allocated to its seven rate classes.

LUI is also requesting Smart Meter Capital and Recovery Variance account disposition which records the net of the amounts paid for direct capital costs related to the smart meter program and the amounts

charged to customers using the OEB- approved smart meter rate adder from May 1, 2006 and projected through to April 30, 2012.

10. LOSS REVENUE ADJUSTMENT MECHANISM (Exhibit 10)

- Is the LRAM amount appropriate?

LUI seeks approval for the recovery of 2010 LRAM amounts as part of this Application. Recovery is to be based on a volumetric rate rider commencing May 1, 2012.

LUI notes that the rate rider requested can be implemented over a one year term, due to the small value and small impact to our rates.

LUI notes that it implemented a number of CDM programs which were included in its third-tranche CDM plans and approved by the OEB. Additionally, LUI participated in several OPA programs from 2006 through 2010. LUI requested and was approved LRAM recoveries in its 2011 IRM rate filing for the period 2006 to 2009.

With continued success in its CDM activities since the previous claim, LUI has additional lost revenue that need to be addressed as part of this COS Application and LUI therefore engaged the services of Burman Energy Consultants Group Inc. (BECGI) to review the preliminary LRAM supporting information and assist us in producing finalized calculations and report suitable to support an LRAM claim as part of this rate submission.

PROCEDURAL ORDERS/MOTIONS/NOTICES

In 2006, the Board established a multi-year rate setting plan for electricity distributors. The plan calls for electricity distributors to have their rates set on a cost of service basis only once over a period of several years, with rates being set using an incentive regulation mechanism (“IRM”) in the intervening years. Subsequently, LUI filed a cost of service rate application in 2008 and is slated for rate rebasing in 2012.

ACCOUNTING ORDERS REQUESTED

LUI is not requesting Accounting Orders in this proceeding.

COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS

LUI 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.

LUI has filed trial balances, financial statements and pro forma financial statements and forecasted results for its 2011 Bridge Year and all proceeding years in accordance with Canadian General Accepted Accounting Principles. ("GAAP").

Pro forma financial statements and forecasted results for LUI's 2012 Test Year are reported in accordance with the proposed modified International Financial Reporting Standards ("IFRS") in compliance with the Board's letter dated March 15, 2011. The Board gave notice of a further amendment to paragraph 9.1.2 of Appendix B to the Report of the Board on the Transition to International Financial Reporting Standards of July, 2009 (EB-2008-0408) as previously amended on November 8, 2010 ("the IFRS Report"), to provide for the filing of certain information using modified IFRS rather than GAAP. The Board stated that distributors whose rates are being rebased for 2012 should make all reasonable efforts to file test year forecasts for their cost of service applications using modified IFRS.

DISTRIBUTION SERVICE TERRITORY AND DISTRIBUTION SYSTEM

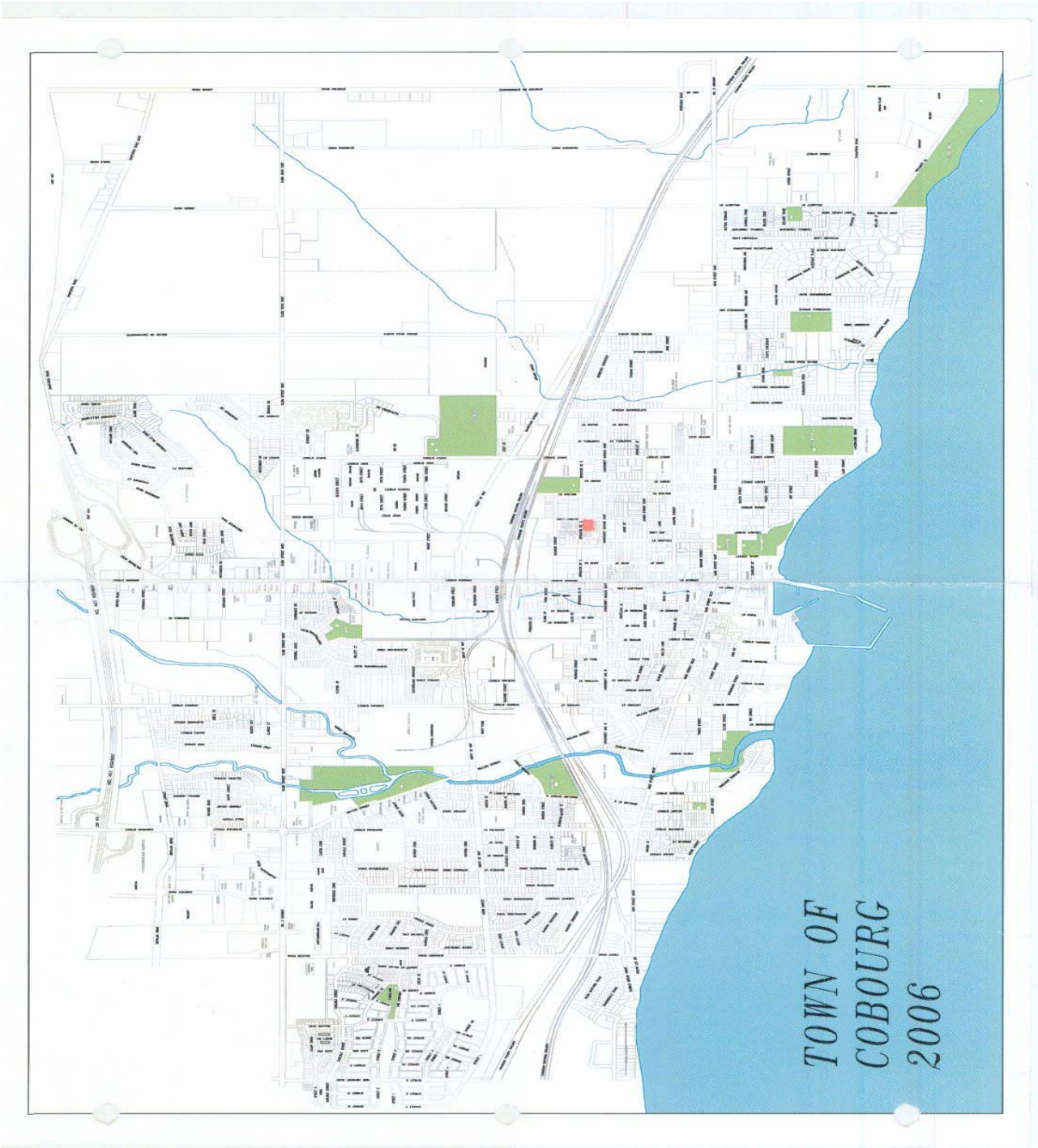
Description of Distributor:

COMMUNITY SERVED:	Town of Cobourg,
	Village of Colborne
TOTAL SERVICE AREA:	27 sq km
RURAL SERVICE AREA:	0 sq km
DISTRIBUTION TYPE:	Electricity distribution
SERVICE AREA POPULATION:	24,300
MUNICIPAL POPULATION:	24,300

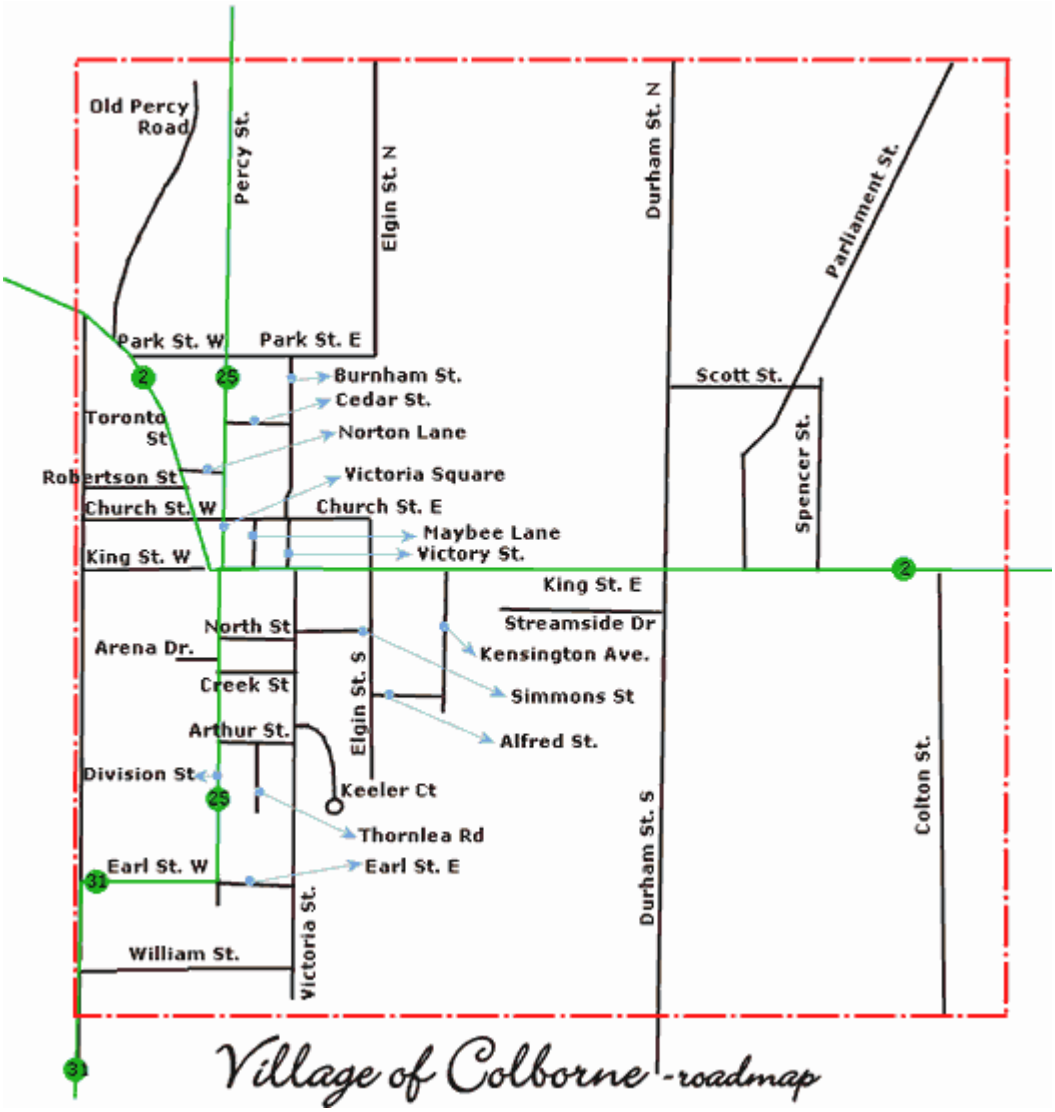
A map of the LUI's Distribution Service Territory accompanies this Schedule as Appendix B.

A schematic diagram of LUI's distribution system is attached in Appendix C.

APPENDIX B MAP OF DISTRIBUTION SERVICE TERRITORY - COBOURG

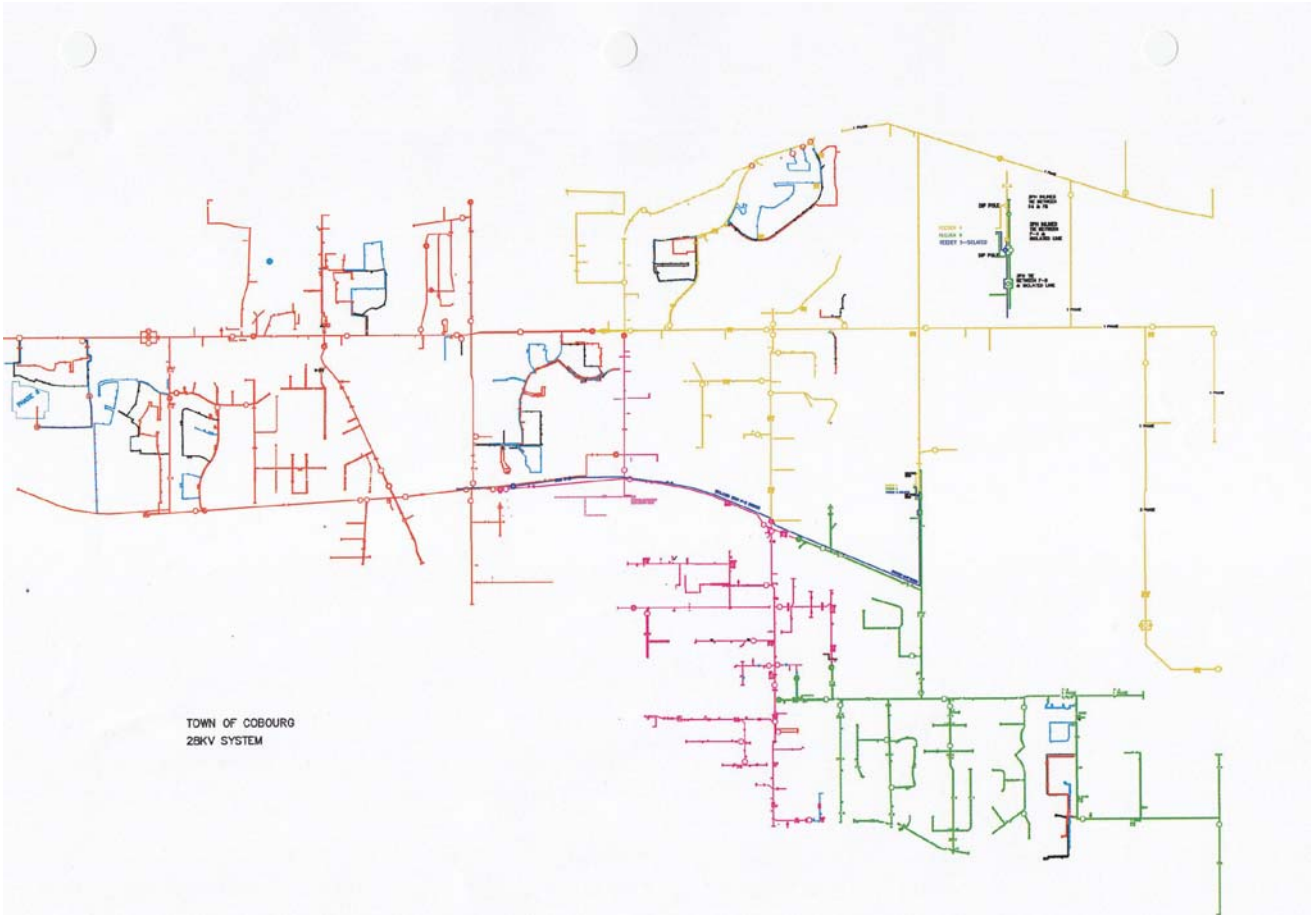


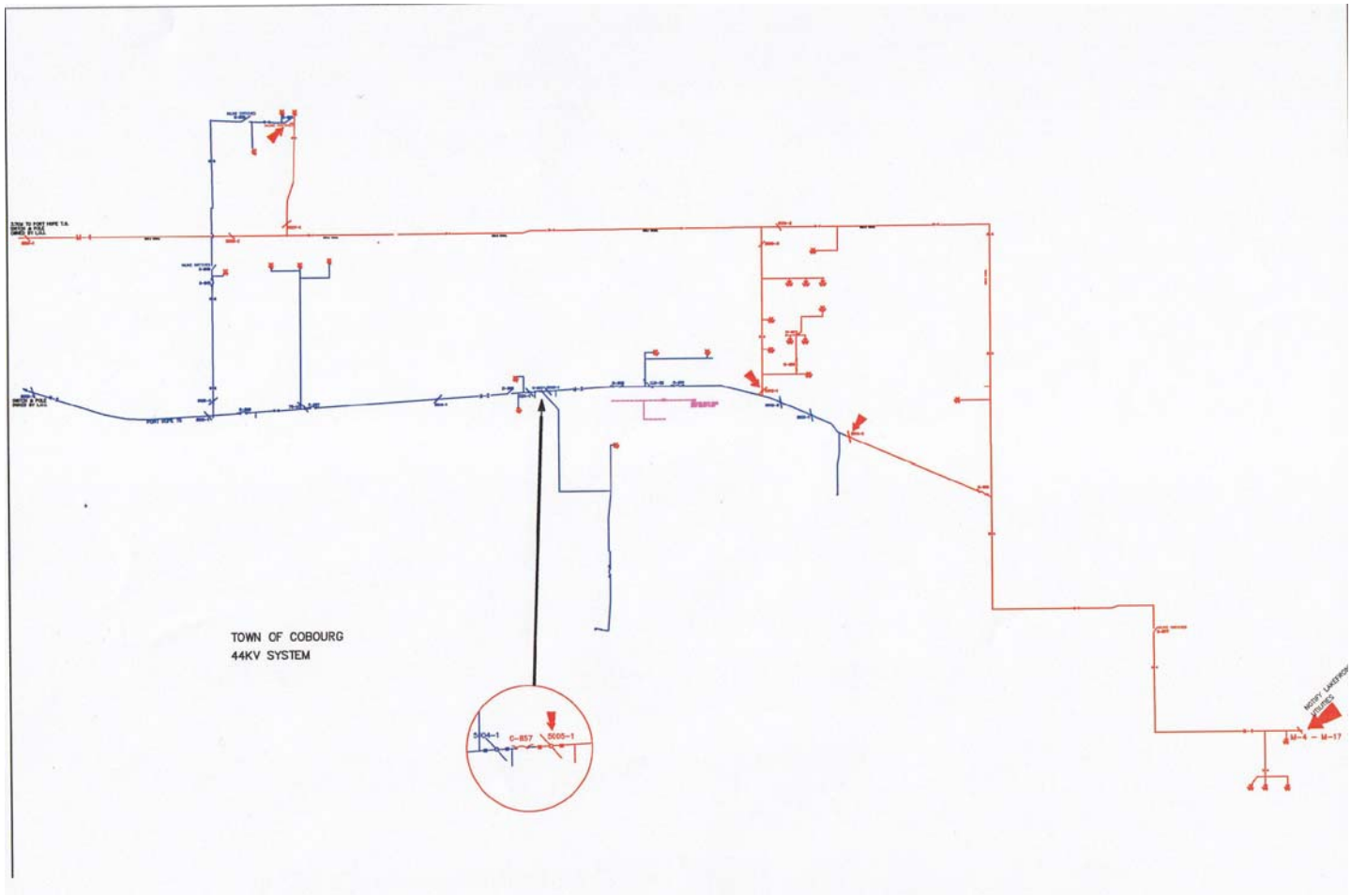
VILLAGE OF COLBORNE

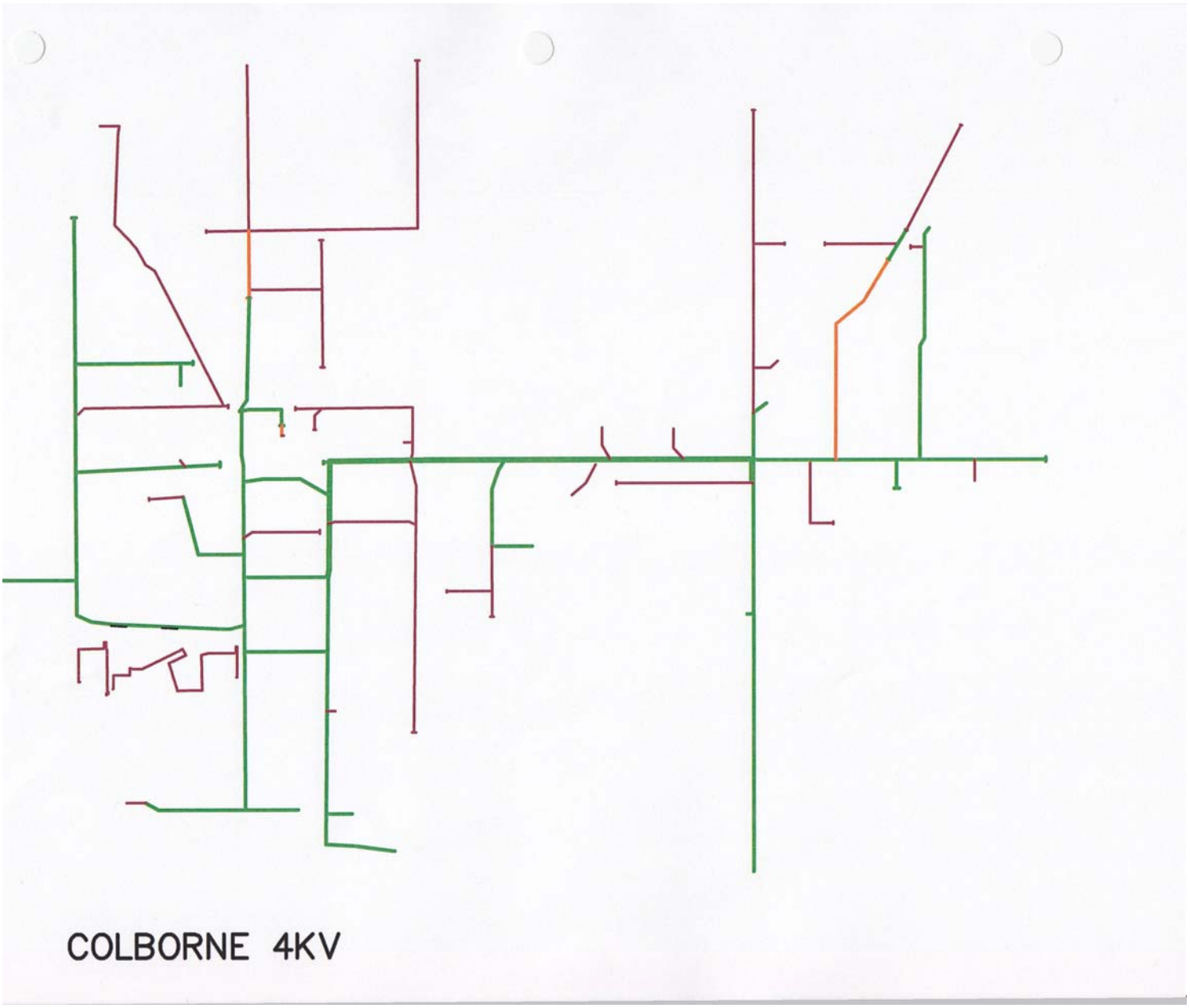


APPENDIX C MAP OF DISTRIBUTION SYSTEM

MAP OF Lakefront Utilities Inc. DISTRIBUTION SYSTEM


TOWN OF COBOURG
28KV SYSTEM


TOWN OF COBOURG
44KV SYSTEM


COLBORNE 4KV

LIST OF NEIGHBOURING UTILITIES

LUI is bounded by : Hydro One in all directions.

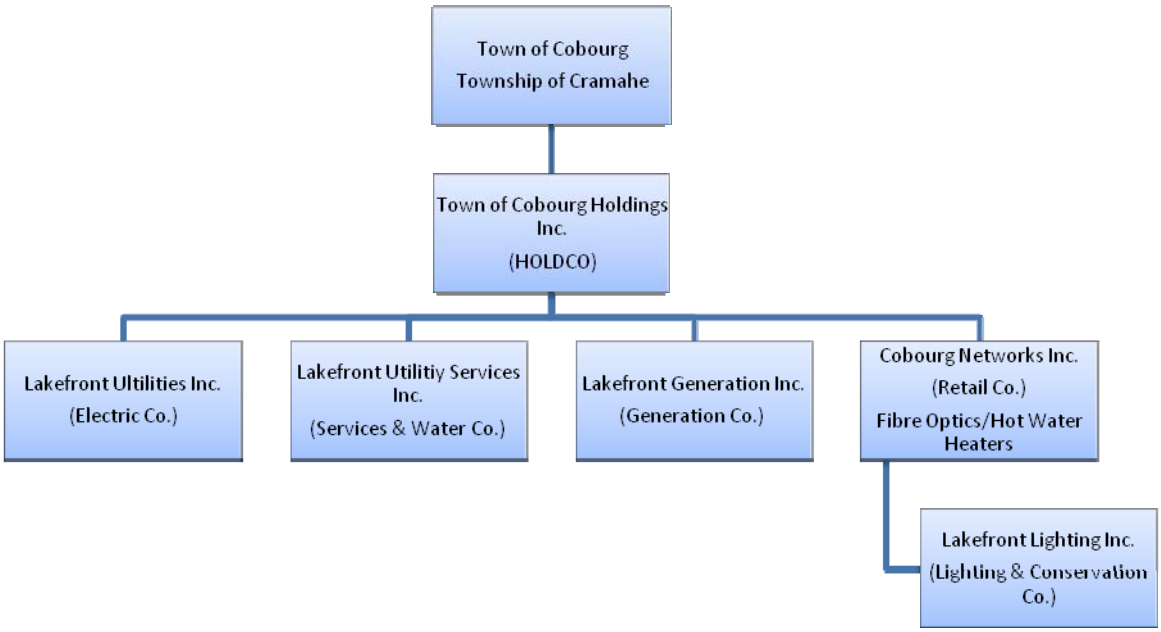
EXPLANATION OF HOST AND EMBEDDED UTILITIES

There are no embedded utilities within LUI's distribution service territory nor is LUI a host utility to other distributors.

UTILITY ORGANIZATIONAL STRUCTURE

LUI is 99.9% owned by the Town of Cobourg and 0.1% owned by the Township of Cramahe. A chart illustrating LUI's corporate family is provided below in Table 1-0

Table 1-0 CORPORATE ENTITIES RELATIONSHIP CHART



LUI is a subsidiary of the Town of Cobourg Holdings Inc. and the associated affiliates are Lakefront Utility Services Inc. ("LUSI"), Cobourg Networks Inc. ("CNI"), Lakefront Generation Inc. ("LGI") and Lakefront Lighting Inc. ("LLI").

In general, LUI shares certain services with its affiliates in functional areas such as Accounting and Information Technology. These services are shared in accordance with Services Agreements between the affliates. The shared services and revenues received have been identified and reported in Exhibit 4 – OM&A Costs ("Exhibit 4"). LUI provides services to its affiliates and purchases services from certain affiliates. In addition LUI pays a fee to its affiliate company, Lakefront Utility Services Inc. (LUSI), for its proportionate share of management services and Board of Directors governance.

LUSI is a service company providing services to LUI, Cobourg Networks Inc (CNI) and Lakefront Generation Inc. (LGI) . LUSI also provides water services to the Town of Cobourg, Village of Grafton and Village of Colborne. The revenues and expenses associated with providing the services are allocated to the recipients at cost. LUSI is not an energy service provider and have separate financial records and books of accounts with an independent Board of Directors from LUI.

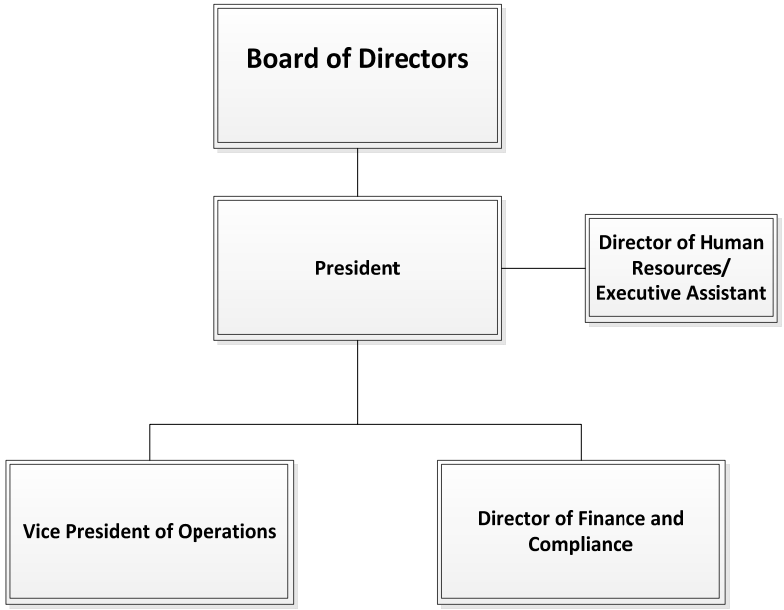
Cobourg Networks Inc. (CNI) provides Internet services to LUI in order for LUI to operate its billing system through the Application Service Provider (ASP) model. CNI is not an energy service provider and have separate financial records and books of accounts with an independent Board of Directors from LUI.

Lakefront Lighting Inc (LLI) is a subsidiary of CNI. LLI, is the retail arm of the affiliates with emphasis in lighting and water conservation sectors. LLI is not an energy service provider and have separate financial records and books of accounts with an independent Board of Directors from LUI.

Lakefront Generation Inc (LGI) is an affiliate of the Lakefront Group of Companies, and seeks out opportunities in energy related activities. LGI is not an energy service provider and have separate financial records and books of accounts with an independent Board of Directors from LUI.

Building and administration expenses are also allocated at cost on a user-based calculation.

Table 1-1 EXECUTIVE AND BOARD ORGANIZATIONAL STRUCTURE



PLANNED CHANGES IN CORPORATE AND OPERATIONAL STRUCTURE

No changes to LUI's corporate and operational structures are planned at the present time. However, LUI is reviewing recent changes to the Affiliate Relationships Code to determine if any changes to the corporate and operational structures are required to perform within the code.

STATUS OF BOARD DIRECTIVES FROM PREVIOUS BOARD DECISIONS

The directive in 2008 Board Decision for LUI was to move revenue/cost ratio for Street Lighting from 12.86% (thirteen percent) to 70% (seventy percent) were effected each year during the IRM process. LUI has completed this objective.

PRELIMINARY LIST OF WITNESSES

LUI is requesting that this Cost of Service Application be disposed of through a written proceeding and is therefore not submitting a list of witnesses or *curricula vitae* with this application. If the Board determines that an oral proceeding is required for this Application, then LUI will provide the required information at that time.

SUMMARY OF THE APPLICATION

LUI is an electricity distribution company licensed by the OEB to provide electricity distribution services to customers with the Town of Cobourg.

LUI's Mission Statement is:

"To provide safe, reliable, and efficient delivery of electrical energy within the Town of Cobourg and the Township of Cramahe while being accountable to our shareholders, the citizens of Cobourg and Colborne."

LUI's Vision Statement is:

"To be acknowledged as a leader among electric utilities in the areas of safety, reliability, customer service, financials and performance."

LUI's strategic priorities as defined in its Corporate Goals:

- ✓ *To form partnerships and alliances with other local distribution companies for economies of scale and cost sharing opportunities. This will be accomplished through participating in the Cornerstone Hydro Electric Concept ("CHEC") group.*
- ✓ *To invest in the development of our staff to provide an employee-oriented, high performance culture of organizational effectiveness that emphasizes empowerment, quality, productivity and standards, goal attainment and ongoing development of a superior workforce.*
- ✓ *To stay current with industry, sector and regulatory changes.*

- ✓ *Lakefront Utilities Inc. has won safety awards in the past and we will seek new ways to further enhance the safety of our employees, our customers and community. In keeping with this vision to pursue health and safety as its top priority, notably, in 2009 LUI was awarded, by the Electrical & Utilities Safety Association (E&USA), the President's Award for having achieved 250,000 Hours Worked Without a Lost Time Accident. LUI achieved another milestone of 350,000 Hours Worked Without a Lost Time Accident in February of 2011.*
- ✓ *To pursue new business opportunities, partnerships and best management practices in our quest to meet or exceed financial expectations of our community by cost sharing, efficiency gains, cost savings, improve reliability, superior customer service and protecting the environment.*
- ✓ *To investigate roles and opportunities that Lakefront Utilities Inc. can pursue in generation and promoting conservation and demand management initiatives.*

Within its service territory, LUI has partnered with local agencies and businesses to deliver innovative conservation and demand management programs.

LUI is committed to staying current with all Regulatory Proceedings, including OEB, OPA, IESO, ESA and MoE. To ensure that its practices and reporting are in compliance with the regulatory rules and participates in many proceedings and working groups with the EDA.

Smart Meters

LUI is requesting disposition of the Smart Meter Capital Deferral account in this application.

Conditions of Service/Service Charges

LUI is currently reviewing and updating its latest version of its Conditions of Service. These will be filed when complete with the Board, at a later date. LUI is a member of the Cornerstone Hydro Electric Concepts Association Inc. (CHEC) group which reviews and changes our Conditions of Service in accordance with changes to the Distribution System Code and Guidelines set out by the Ontario Energy Board.

Customer Impact

In preparing this application, LUI has considered the impacts on its customers, with a goal of minimizing those impacts. With respect to cost allocation, LUI notes that for the majority of its customers, the current revenue to cost ratio of each rate class does fall within the applicable threshold defined by the OEB in the November 28, 2007, Report on Application of Cost Allocation for Electricity Distributors. LUI has updated the Cost Allocation model for the 2012 forecast year. However, there is one class of customer the GS> 3000-4999 that does not fall within the board range, and as a result, adjustments have been made in this Application to move the GS> 3000-4999 customer class up towards the board approved range of the revenue –to-cost ratios. In the last Cost of Service, LUI was required to move the Sentinel and Streetlight customer classes up into the acceptable ranges for revenue-to-cost ratios. LUI was able to achieve the approved ratios between 2008 to 2011.

Table 1-2 TOTAL BILL IMPACT – PERCENT & DOLLAR

RESIDENTIAL

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			9.29			12.25	2.96	31.86%	10.17%
800 kWh	Distribution (kWh)	800	0.0134	10.72	800	0.0177	14.16	3.44	32.09%	11.76%
	Low Voltage Rider (kWh)	800	0.0013	1.04	800	0.0013	1.04	0.00	0.00%	0.86%
	Stranded Meters Rate Rider ($/Customer)			0.00			2.37	2.37		1.97%
	LRAM & SSM Rider (kWh)	800	0.0011	0.88	800	0.0002	0.19	(0.69)	(78.74%)	0.16%
	Smart Meter Rate Rider ($/Customer)			2.50			0.05	(2.45)	(98.00%)	0.04%
	Late Payment (kWh)	1	0.1800	0.18	1	0.0000	0.00	(0.18)	(100.00%)	0.00%
	Deferrral & Variance Acct (kWh)	800	0.0014	1.12	800	(0.0005)	(0.39)	(1.51)	(134.48%)	(0.32%)
	Distribution Sub-Total			**25.73**			**29.67**	**3.94**	**15.32%**	**24.64%**
	Retail Transmisssion (kWh)	843	0.0097	8.18	845.22	0.009946716	8.41	0.23	2.78%	6.98%
	Delivery Sub-Total			**33.91**			**38.08**	**4.17**	**12.29%**	**31.62%**
	Other Charges (kWh)	843	0.0131	11.07	845.22	0.0131	11.09	0.03	0.23%	9.21%
	Cost of Power Commodity (kWh)	600	0.0650	39.00	600.00	0.0650	39.00	0.00	0.00%	32.39%
	Cost of Power Commodity (kWh)	243.28	0.075000	18.246000	245.22	0.0750	18.39	0.15	0.80%	15.27%
	SPC (kWh)	843	0.0000	0.00	843.28	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**102.22**			**106.56**	**4.35**	**4.25%**	**88.50%**
	GST		13.00%	13.29		13.00%	13.85	0.56	4.24%	11.50%
	Total Bill			**115.51**			**120.42**	**4.92**	**4.26%**	**100.00%**

GENERAL SERVICE < 50 kW

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			22.50			28.02	5.52	24.53%	9.86%
2,000 kWh	Distribution (kWh)	2,000	0.0081	16.20	2,000	0.0101	20.20	4.00	24.69%	7.11%
	Low Voltage Rider (kWh)	2,000	0.0012	2.40	2,000	0.0012	2.40	0.00	0.00%	0.84%
	Stranded Meters Rate Rider ($/Customer)			2.50			2.37	(0.13)	(5.20%)	0.83%
	LRAM & SSM Rider (kWh)	2,000	0.0002	0.40	2,000	0.0002	0.39	(0.01)	(3.35%)	0.14%
	Smart Meter Rate Rider ($/Customer)			2.50			0.05	(2.45)	(98.00%)	0.02%
	Late Payment (kWh)	1	0.4400	0.44	1	0.0000	0.00	(0.44)	(100.00%)	0.00%
	Deferrral & Variance Acct (kWh)	2,000	0.0015	3.00	2,000	(0.0006)	(1.27)	(4.27)	(142.38%)	(0.45%)
	Distribution Sub-Total			**49.94**			**52.16**	**2.22**	**4.44%**	**18.36%**
	Retail Transmisssion (kWh)	2,108	0.0088	18.55	2,113.05	0.00902383	19.07	0.52	2.78%	6.71%
	Delivery Sub-Total			**68.49**			**71.22**	**2.73**	**3.99%**	**25.07%**
	Other Charges (kWh)	2,108.20	0.013125	27.67	2,113	0.0131	27.73	0.06	0.23%	9.76%
	Cost of Power Commodity (kWh)	600.00	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	13.73%
	Cost of Power Commodity (kWh)	1,508.20	0.0750	113.12	1,513	0.0750	113.48	0.36	0.32%	39.94%
	SPC (kWh)	2,108.20	0.0000	0.00	2,108	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**248.28**			**251.43**	**$3.16**	**1.27%**	**88.49%**
	GST		13.00%	32.28		13.00%	32.69	0.41	1.27%	11.50%
	Total Bill			**280.55**			**284.12**	**$3.57**	**1.27%**	**100.00%**

BUDGET DIRECTIVES

LUI compiles budget information for the three major components of the budgeting process: **Revenue Forecasts, Operating Maintenance and Administration (OM&A) Expense Forecast** and C**apital Budget Forecast**. This budget information is compiled using historical evidence for both the 2011 Bridge Year and the 2012 Test Year forecasts and ensures fair and accurate assumptions.

Revenue Forecast

LUI's energy sales and revenue forecast model was updated to reflect the most recent information. This model was then used to prepare the revenues sales and throughput volume and revenue forecast at existing rates for fiscal 2011 and 2012. The forecast is weather normalized as outlined in Exhibit 3 and considers such factors as new customer additions, customer class changes, and load profiles for all classes of customers.

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

The OM&A expenses for the 2011 Bridge Year and the 2012 Test Year have been based on an in-depth review of operating priorities and requirements and is strongly influenced by prior year experience. Each item is reviewed account by account for each of the forecast years with costs allocated for budget presentation.

Capital Budget

The capital budget forecast 2011 and 2012 is influenced, among other factors, by LUI's capacity to finance capital projects. LUI coordinates work with Town projects in order to achieve economies of scale. All proposed capital projects are assessed within the framework of its priority and are outlined in Exhibit 2 (Capital Expenditures by Project).

In addition, more than two decades ago, LUI started voltage conversion from 4.16kV to 27.6 kV system. This conversion continues today and will for the next 5 to 10 years at least. As a result of this conversion

and future growth, LUI requires more capacity to service the 27.6 kV system and therefore has begun the studies in 2011 to build a third strategically located 27.6kV municipal sub-station with a planned in service date of 2015. Currently the costs associated with the new substation are being accumulated in to WIP and are not included in Rate Base . The new station will provide additional capacity for future load growth and will enable the transfer of the existing 4.16kV load to the 27.6kV system and permit the discontinuance of the existing four aging inefficient 4.16kV sub-stations.

LUI is also currently working on expanding the Operational WorkCentre on Ewart Street.

CHANGES IN METHODOLOGY

LUI is not requesting any changes in methodology in the current proceeding with exception to that pro forma financial statements and forecasted results for LUI's Test Year ending December 31, 2012, are reported in accordance with proposed modified IFRS in compliance with the Boards letter dated March 15, 2011. The Board gave notice of a further amendment to paragraph 9.1.2 of Appendix B to report of the Board on the Transition to

CAUSES OF REVENUE DEFICIENCY/CALCULATION OF REVENUE DEFICIENCY UNDER MODIFIED IFRS

LUI has provided detailed calculations supporting its 2012 revenue deficiency. LUI's net revenue deficiency is calculated as $ **628,630** and when grossed up for PILs, the revenue deficiency is $ 743,941 . Lakefront Utilities Inc's calculation of its 2012 revenue deficiency is provided in Exhibit 6.

The revenue deficiency is primarily the result of:

- Labour and Payroll Costs
- Depreciation
- Modified IFRS

- OM&A
- Capital Expenditures

LUI is committed to meeting its corporate mission and goals of providing a safe and reliable distribution through prudent investments in capital assets and investing in training and education of staff required to meet the future needs of its customers.

APPENDIX D REVENUE REQUIREMENT WORKFORM

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$22,295,173	$ -	$22,295,173	$ -	$22,295,173
2	Accumulated Depreciation (average)	(3)	($8,695,275)	$ -	($8,695,275)	$ -	($8,695,275)
3	Net Fixed Assets (average)	(3)	$13,599,899	$ -	$13,599,899	$ -	$13,599,899
4	Allowance for Working Capital	(1)	$3,926,020	$ -	$3,926,020	$ -	$3,926,020
5	**Total Rate Base**		$17,525,919	$ -	$17,525,919	$ -	$17,525,919

Allowance for Working Capital - Derivation

(1)

6	Controllable Expenses		$3,116,856	$ -	$3,116,856	$ -	$3,116,856
7	Cost of Power		$23,056,611	$ -	$23,056,611	$ -	$23,056,611
8	Working Capital Base		$26,173,467	$ -	$26,173,467	$ -	$26,173,467
9	Working Capital Rate %	(2)	15.00%	0.00%	15.00%	0.00%	15.00%
10	Working Capital Allowance		$3,926,020	$ -	$3,926,020	$ -	$3,926,020

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study.
(3) Average of opening and closing balances for the year.

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$4,752,742	($4,752,742)	$ -	$ -	$ -
2	Other Revenue	(1)	$378,462	($378,462)	$ -	$ -	$ -
3	Total Operating Revenues		$5,131,204	($5,131,204)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$3,067,314	$ -	$3,067,314	$ -	$3,067,314
5	Depreciation/Amortization		$816,209	$ -	$816,209	$ -	$816,209
6	Property taxes		$49,542	$ -	$49,542	$ -	$49,542
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$3,933,064	$ -	$3,933,064	$ -	$3,933,064
10	Deemed Interest Expense		$491,348	($491,348)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)		$4,424,412	($491,348)	$3,933,064	$ -	$3,933,064
12	**Utility income before income taxes**		$706,791	($4,639,856)	($3,933,064)	$ -	($3,933,064)
13	Income taxes (grossed-up)		$35,198	$ -	$35,198	$ -	$35,198
14	**Utility net income**		$671,593	($4,639,856)	($3,968,262)	$ -	($3,968,262)

Notes

Other Revenues / Revenue Offsets

(1)	Specific Service Charges		$126,500		$ -		$ -
	Late Payment Charges		$63,140		$ -		$ -
	Other Distribution Revenue		$160,322		$ -		$ -
	Other Income and Deductions		$28,500		$ -		$ -
	Total Revenue Offsets		$378,462	$ -	$ -	$ -	$ -

Line No.	Particulars	Application	Settlement Agreement	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$671,593	$ -	$ -
2	Adjustments required to arrive at taxable utility income	($479,707)	$ -	($479,707)
3	Taxable income	$191,886	$ -	($479,707)
	Calculation of Utility income Taxes			
4	Income taxes	$29,742	$29,742	$29,742
6	Total taxes	$29,742	$29,742	$29,742
7	Gross-up of Income Taxes	$5,456	$5,456	$5,456
8	Grossed-up Income Taxes	$35,198	$35,198	$35,198
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$35,198	$35,198	$35,198
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	0.50%	0.50%	0.50%
13	Total tax rate (%)	15.50%	15.50%	15.50%

1

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$9,814,514	4.83%	$474,102
2	Short-term Debt	4.00%	$701,037	2.46%	$17,246
3	**Total Debt**	60.00%	$10,515,551	4.67%	$491,348
	Equity				
4	Common Equity	40.00%	$7,010,367	9.58%	$671,593
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$7,010,367	9.58%	$671,593
7	**Total**	100.00%	$17,525,919	6.64%	$1,162,941
		Settlement Agreement			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$ -
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
4	Common Equity	0.00%	$ -	0.00%	$ -
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	$ -
7	**Total**	0.00%	$17,525,919	0.00%	$ -
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	0.00%	$ -	4.83%	$ -
9	Short-term Debt	0.00%	$ -	2.46%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	9.58%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$17,525,919	0.00%	$ -

Notes

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

Line No.	Particulars	Initial Application		Settlement Agreement		Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$743,941		($163,730)		$3,933,064
2	Distribution Revenue	$4,008,801	$4,008,801	$4,008,801	$4,916,471	$ -	($3,933,064)
3	Other Operating Revenue Offsets - net	$378,462	$378,462	$ -	$ -	$ -	$ -
4	**Total Revenue**	$4,387,263	$5,131,204	$4,008,801	$4,752,742	$ -	$ -
5	Operating Expenses	$3,933,064	$3,933,064	$3,933,064	$3,933,064	$3,933,064	$3,933,064
6	Deemed Interest Expense	$491,348	$491,348	$ -	$ -	$ -	$ -
	Total Cost and Expenses	$4,424,412	$4,424,412	$3,933,064	$3,933,064	$3,933,064	$3,933,064
7	**Utility Income Before Income Taxes**	($37,150)	$706,791	$75,736	$819,677	($3,933,064)	($3,933,064)
8	Tax Adjustments to Accounting Income per 2009 PILs	($479,707)	($479,707)	($479,707)	($479,707)	$ -	$ -
9	**Taxable Income**	($516,857)	$227,084	($403,971)	$339,970	($3,933,064)	($3,933,064)
10	Income Tax Rate	15.50%	15.50%	15.50%	15.50%	15.50%	15.50%
11	**Income Tax on Taxable Income**	($80,113)	$35,198	($62,615)	$52,695	($609,625)	($609,625)
12	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
13	**Utility Net Income**	$42,963	$671,593	$138,352	($3,968,262)	($3,323,439)	($3,968,262)
14	**Utility Rate Base**	$17,525,919	$17,525,919	$17,525,919	$17,525,919	$17,525,919	$17,525,919
	Deemed Equity Portion of Rate Base	$7,010,367	$7,010,367	$ -	$ -	$ -	$ -
15	Income/(Equity Portion of Rate Base)	0.61%	9.58%	0.00%	0.00%	0.00%	0.00%
16	Target Return - Equity on Rate Base	9.58%	9.58%	0.00%	0.00%	0.00%	0.00%
17	Deficiency/Sufficiency in Return on Equity	-8.97%	0.00%	0.00%	0.00%	0.00%	0.00%
18	Indicated Rate of Return	3.05%	6.64%	0.79%	0.00%	-18.96%	0.00%
19	Requested Rate of Return on Rate Base	6.64%	6.64%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Rate of Return	-3.59%	0.00%	0.79%	0.00%	-18.96%	0.00%
21	Target Return on Equity	$671,593	$671,593	$ -	$ -	$ -	$ -
22	Revenue Deficiency/(Sufficiency)	$628,630	$0	($138,352)	$ -	$3,323,439	$ -
23	**Gross Revenue Deficiency/(Sufficiency)**	$743,941 **(1)**		($163,730) **(1)**		$3,933,064 **(1)**	

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

Line No.	Particulars	Application		Settlement Agreement		Per Board Decision
1	OM&A Expenses	$3,067,314		$3,067,314		$3,067,314
2	Amortization/Depreciation	$816,209		$816,209		$816,209
3	Property Taxes	$49,542		$49,542		$49,542
5	Income Taxes (Grossed up)	$35,198		$35,198		$35,198
6	Other Expenses	$ -				
7	Return					
	Deemed Interest Expense	$491,348		$ -		$ -
	Return on Deemed Equity	$671,593		$ -		$ -
8	**Service Revenue Requirement (before Revenues)**	$5,131,204		$3,968,262		$3,968,262
9	Revenue Offsets	$378,462		$ -		$ -
10	**Base Revenue Requirement**	$4,752,741		$3,968,262		$3,968,262
11	Distribution revenue	$4,752,742		$ -		$ -
12	Other revenue	$378,462		$ -		$ -
13	**Total revenue**	$5,131,204		$ -		$ -
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0	(1)	($3,968,262)	(1)	($3,968,262)

Notes

(1) Line 11 - Line 8

☐ Application of New Loss Factor to all applicable items ☐ Application of new Loss Factor to Deliv

Consumption 800 **kWh**

			Current Board-Approved			Proposed			Impact	
		Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
1	Monthly Service Charge	monthly	$ 9.2900	1	$ 9.29	$ 12.2500	1	$ 12.25	$ 2.96	31.86%
2	Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
3	Service Charge Rate Adder(s)			1	$ -	$ -	1	$ -	$ -	
4	Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
5	Distribution Volumetric Rate	per kWh	$ 0.0134	800	$ 10.72	$ 0.0177	800	$ 14.16	$ 3.44	32.09%
6	Low Voltage Rate Adder	per kWh	$ 0.0013	800	$ 1.04	$ 0.0013	800	$ 1.04	$ -	0.00%
7	Volumetric Rate Adder(s)			800	$ -		800	$ -	$ -	
8	Volumetric Rate Rider(s)			800	$ -		800	$ -	$ -	
9	Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
10	LRAM & SSM Rate Rider	per kWh	$ 0.0011	800	$ 0.88	$ 0.0002	800	$ 0.19	-$ 0.69	-78.74%
11	Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0014	800	$ 1.12	-$ 0.0007	800	-$ 0.57	-$ 1.69	-150.97%
12	Stranded Meter Rider	monthly	$ -	1	$ -	$ 2.3699	1	$ 2.37	$ 2.37	
13	Smart Meter Rate Rider	monthly	$ 2.5000	1	$ 2.50	$ 0.0500	1	$ 0.05	-$ 2.45	-98.00%
14	Late Payment Penalty	monthly	$ 0.1800	1	$ 0.18			$ -	-$ 0.18	-100.00%
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 25.73**			**$ 29.49**	**$ 3.76**	**14.60%**
17	RTSR - Network	per kWh	$ 0.0054	843.28	$ 4.55	$ 0.0055	845.2	$ 4.69	$ 0.14	2.97%
18	RTSR - Line and Transformation Connection	per kWh	$ 0.0043	843.28	$ 3.63	$ 0.0044	845.2	$ 3.72	$ 0.09	2.53%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 33.91**			**$ 37.89**	**$ 3.98**	**11.75%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0065	843.28	$ 5.48		845.2	$ -	-$ 5.48	-100.00%
21	Rural and Remote Rate Protection (RRRP)			843.28	$ -		845.2	$ -	$ -	
22	Special Purpose Charge	per kWh	$ -	843.28	$ -	$ -	845.2	$ -	$ -	
23	Standard Supply Service Charge			1	$ -		1	$ -	$ -	
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60		800	$ -	-$ 5.60	-100.00%
25	Energy			843.28	$ -	$ 0.0131	845.2	$ 11.09	$ 11.09	
26	First Block	per kWh	$ 0.0650	600	$ 39.00	$ 0.0650	600	$ 39.00	$ -	0.00%
27	Balance Block	per kWh	$ 0.0750	243	$ 18.23	$ 0.0750	245.22	$ 18.39	$ 0.17	0.91%
28	**Total Bill (before Taxes)**				**$ 102.22**			**$ 106.38**	**$ 4.16**	**4.07%**
29	HST		13%		$ 13.29	13%		$ 13.83	$ 0.54	4.07%
30	**Total Bill (including Sub-total B)**				**$ 115.50**			**$ 120.21**	**$ 4.71**	**4.08%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 11.55**	-10%		**-$ 12.02**	**-$ 0.47**	**4.07%**
32	**Total Bill (including OCEB)**				**$ 103.95**			**$ 108.19**	**$ 4.24**	**4.08%**
33	**Loss Factor (%)**	**Note 1**	5.41%			5.65%				

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	monthly	$ 22.5000	1	$ 22.50	$ 28.0200	1	$ 28.02	$ 5.52	24.53%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Service Charge Rate Adder(s)	per kWh	$ 0.4400	1	$ 0.44	$ -	1	$ -	-$ 0.44	-100.00%
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0081	2000	$ 16.20	$ 0.0101	2000	$ 20.20	$ 4.00	24.69%
Low Voltage Rate Adder	per kWh	$ 0.0012	2000	$ 2.40	$ 0.0012	2000	$ 2.40	$ -	0.00%
Volumetric Rate Adder(s)			2000	$ -		2000	$ -	$ -	
Volumetric Rate Rider(s)			2000	$ -		2000	$ -	$ -	
Smart Meter Disposition Rider			2000	$ -		2000	$ -	$ -	
LRAM & SSM Rider	per kWh	$ 0.0002	2000	$ 0.40	$ 0.0002	2000	$ 0.39	-$ 0.01	-3.35%
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0015	2000	$ 3.00	-$ 0.0009	2000	-$ 1.73	-$ 4.73	-157.67%
Stranded Meter Rider	monthly	$ 2.5000	1	$ 2.50	$ 2.3699	1	$ 2.37	-$ 0.13	-5.20%
Smart Meter Rate Rider	monthly	$ 2.5000	1	$ 2.50	$ 0.0500	1	$ 0.05	-$ 2.45	-98.00%
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 49.94**			**$ 51.70**	**$ 1.76**	**3.52%**
RTSR - Network	per kWh	$ 0.0049	2108.2	$ 10.33	$ 0.0050	2113	$ 10.64	$ 0.31	2.97%
RTSR - Line and Transformation Connection	per kWh	$ 0.0039	2108.2	$ 8.22	$ 0.0040	2113	$ 8.43	$ 0.21	2.53%
Sub-Total B - Delivery (including Sub-Total A)				**$ 68.49**			**$ 70.76**	**$ 2.27**	**3.32%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0065	2108.2	$ 13.70	$ 0.0065	2113	$ 13.73	$ 0.03	0.23%
Rural and Remote Rate Protection (RRRP)			2108.2	$ -		2113	$ -	$ -	
Special Purpose Charge	per kWh	$ -	2108.2	$ -	$ -	2113	$ -	$ -	
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 13.97	$ 0.0070	2000	$ 14.00	$ 0.03	0.23%
Energy			2108.2	$ -		2113	$ -	$ -	
First Block	per kWh	$ 0.0650	600	$ 39.00	$ 0.0650	600	$ 39.00	$ -	0.00%
Balance Block	per kWh	$ 0.0750	1508.2	$ 113.12	$ 0.0750	1513	$ 113.48	$ 0.36	0.32%
Total Bill (before Taxes)				**$ 248.28**			**$ 250.97**	**$ 2.69**	**1.09%**
HST		13%		$ 32.28	13%		$ 32.63	$ 0.35	1.09%
Total Bill (including Sub-total B)				**$ 280.55**			**$ 283.60**	**$ 3.05**	**1.09%**
Ontario Clean Energy Benefit (OCEB)		-10%		**-$ 28.06**	-10%		**-$ 28.36**	**-$ 0.30**	**1.07%**
Total Bill (including OCEB)				**$ 252.49**			**$ 255.24**	**$ 2.75**	**1.09%**
Loss Factor	**(1)**	5.41%			5.65%				

The LUI Pro Forma Statements for the 2011 Bridge Year and the 2012 Test Year accompany this Schedule as Appendix E and Appendix F respectively.

APPENDIX E COPY OF Lakefront Utilities Inc. 2011 PRO FORMA STATEMENTS

Lakefront Utilities Inc.
2011 BALANCE SHEET

Account Description	Total
1050-Current Assets	
1005-Cash	4,116,178
1010-Cash Advances and Working Funds	0
1020-Interest Special Deposits	0
1030-Dividend Special Deposits	0
1040-Other Special Deposits	0
1060-Term Deposits	0
1070-Current Investments	0
1100-Customer Accounts Receivable	1,799,794
1102-Accounts Receivable - Services	0
1104-Accounts Receivable - Recoverable Work	0
1105-Accounts Receivable - Merchandise, Jobbing, etc.	90,000
1110-Other Accounts Receivable	20,000
1120-Accrued Utility Revenues	3,500,000
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(40,000)
1140-Interest and Dividends Receivable	0
1150-Rents Receivable	0
1170-Notes Receivable	0
1180-Prepayments	51,000
1190-Miscellaneous Current and Accrued Assets	700
1200-Accounts Receivable from Associated Companies	0
1210-Notes Receivable from Associated Companies	0
1050-Current Assets Total	**9,537,672**

1100-Inventory	
1305-Fuel Stock	0
1330-Plant Materials and Operating Supplies	240,000
1340-Merchandise	0
1350-Other Material and Supplies	0
1100-Inventory Total	**240,000**

1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	0
1408-Long Term Receivable - Street Lighting Transfer	0
1410-Other Special or Collateral Funds	0
1415-Sinking Funds	0
1425-Unamortized Debt Expense	0
1445-Unamortized Discount on Long-Term Debt--Debit	0
1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	0
1460-Other Non-Current Assets	0
1465-O.M.E.R.S. Past Service Costs	0
1470-Past Service Costs - Employee Future Benefits	0
1475-Past Service Costs -Other Pension Plans	0
1480-Portfolio Investments - Associated Companies	0
1485-Investment In Subsidiary Companies - Significant Influence	0
1490-Investment in Subsidiary Companies	0
1150-Non-Current Assets Total	**0**

1200-Other Assets and Deferred Charges	
1505-Unrecovered Plant and Regulatory Study Costs	0
1508-Other Regulatory Assets	9,242
1510-Preliminary Survey and Investigation Charges	0
1515-Emission Allowance Inventory	0
1516-Emission Allowance Withheld	0
1518-RCVA Retail	44,297
1525-Miscellaneous Deferred Debits & 1521 SPC	58,288
1530-Deferred Losses from Disposition of Utility Plant	0
1540-Deferred Losses from Disposition of Utility Plant	0
1545-Development Charge Deposits/ Receivables	0
1548-RCVA - Service Transaction Request (STR)	40,408
1550-LV Charges - Variance	(234,703)
1555-Smart Meters Recovery	0
1556-Smart Meters OM & A	76,723
1562-Deferred PILs	(97,488)
1563-Deferred PILs - Contra	97,488
1565-C & DM Costs	0
1566-C & DM Costs Contra	0
1570-Qualifying Transition Costs	0
1571-Pre Market CofP Variance	0
1572-Extraordinary Event Losses	0
1574-Deferred Rate Impact Amounts	0
1580-RSVA - Wholesale Market Services	(325,368)
1582-RSVA - One-Time	17,991
1584-RSVA - Network Charges	28,722
1586-RSVA - Connection Charges	42,157
1588-RSVA - Commodity (Power)	73,808
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	0
1592-PILs and Tax Variance for 2006 & Subsequent Years	0
1595-Disposition and Recovery of Regulatory Balances	226,737
1200-Other Assets and Deferred Charges Total	**58,301**

1450-Distribution Plant	
1610-Intangible Assets	0
1805-Land	219,284
1806-Land Rights	0
1808-Buildings and Fixtures	994,216
1810-Leasehold Improvements	0
1815-Transformer Station Equipment - Normally Primary above 50 kV	0
1820-Distribution Station Equipment - Normally Primary below 50 kV	2,762,235
1825-Storage Battery Equipment	0
1830-Poles, Towers and Fixtures	1,557,311
1835-Overhead Conductors and Devices	4,213,754
1840-Underground Conduit	1,228,943
1845-Underground Conductors and Devices	3,066,154
1850-Line Transformers	5,351,049
1855-Services	599,529
1860-Meters	2,047,905
1865-Other Installations on Customer's Premises	0
1450-Distribution Plant Total	**22,040,380**

1500-General Plant	
1905-Land	0
1906-Land Rights	0
1908-Buildings and Fixtures	0
1910-Leasehold Improvements	0
1915-Office Furniture and Equipment	82,026
1920-Computer Equipment - Hardware	81,199
1925-Computer Software	287,582
1930-Transportation Equipment	759,705
1935-Stores Equipment	0
1940-Tools, Shop and Garage Equipment	233,730
1945-Measurement and Testing Equipment	18,712
1950-Power Operated Equipment	0
1955-Communication Equipment	0
1960-Miscellaneous Equipment	0
1970-Load Management Controls - Customer Premises	0
1975-Load Management Controls - Utility Premises	0
1980-System Supervisory Equipment	0
1985-Sentinel Lighting Rentals	0
1990-Other Tangible Property	0
1995-Contributions and Grants	(2,257,659)
1500-General Plant Total	**(794,706)**

1550-Other Capital Assets	
2005-Property Under Capital Leases	0
2010-Electric Plant Purchased or Sold	0
2020-Experimental Electric Plant Unclassified	0
2030-Electric Plant and Equipment Leased to Others	0
2040-Electric Plant Held for Future Use	0
2050-Completed Construction Not Classified--Electric	0
2055-Construction Work in Progress--Electric	0
2060-Electric Plant Acquisition Adjustment	0
2065-Other Electric Plant Adjustment	0
2070-Other Utility Plant	0
2075-Non-Utility Property Owned or Under Capital Lease	0
1550-Other Capital Assets Total	**0**

1600-Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(8,287,170)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	0
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	0
2160-Accumulated Amortization of Other Utility Plant	0
2180-Accumulated Amortization of Non-Utility Property	0
1600-Accumulated Amortization Total	**(8,287,170)**

Total Assets	**22,794,476**

1650-Current Liabilities	
2205-Accounts Payable	2,300,000
2208-Customer Credit Balances	123,410
2210-Current Portion of Customer Deposits	77,994
2215-Dividends Declared	0
2220-Miscellaneous Current and Accrued Liabilities	300,000
2225-Notes and Loans Payable	0
2240-Accounts Payable to Associated Companies	0
2242-Notes Payable to Associated Companies	0
2250-Debt Retirement Charges (DRC) Payable	121,000
2252-Transmission Charges Payable	0
2254-Electric Safety Authority Fees Payable	0
2256-Independent Market Operator Fees and Penalties Payable	0
2260-Current Portion of Long Term Debt	0
2262-Ontario Hydro Debt - Current Portion	0
2264-Pensions and Employee Benefits - Current Portion	0
2268-Accrued Interest on Long Term Debt	0
2270-Matured Long Term Debt	0
2272-Matured Interest on Long Term Debt	0
2285-Obligations Under Capital Leases--Current	0
2290-Commodity Taxes	100,000
2292-Payroll Deductions / Expenses Payable	0
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	(10,000)
2296-Future Income Taxes - Current	0
1650-Current Liabilities Total	**3,012,404**

1700-Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	0
2306-Employee Future Benefits	295,837
2308-Other Pensions - Past Service Liability	0
2310-Vested Sick Leave Liability	0
2315-Accumulated Provision for Rate Refunds	0
2320-Other Miscellaneous Non-Current Liabilities	0
2325-Obligations Under Capital Lease--Non-Current	0
2330-Devolpment Charge Fund	0
2335-Long Term Customer Deposits	0
2340-Collateral Funds Liability	0
2345-Unamortized Premium on Long Term Debt	0
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	0
2350-Future Income Tax - Non-Current	0
2405-Other Regulatory Liabilities	(58,000)
2410-Deferred Gains From Disposition of Utility Plant	0
2415-Unamortized Gain on Reacquired Debt	0
2425-Other Deferred Credits	0
2435-Accrued Rate-Payer Benefit	0
1700-Non-Current Liabilities Total	**237,837**

1800-Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	5,800,000
2510-Debenture Advances	0
2515-Required Bonds	0
2520-Other Long Term Debt	7,000,000
2525-Term Bank Loans - Long Term Portion	0
2530-Ontario Hydro Debt Outstanding - Long Term Portion	0
2550-Advances from Associated Companies	0
1800-Long-Term Debt Total	**12,800,000**

1850-Shareholders' Equity	
3005-Common Shares Issued	5,293,376
3008-Preference Shares Issued	0
3010-Contributed Surplus	0
3020-Donations Received	0
3022-Devolpment Charges Transferred to Equity	0
3026-Capital Stock Held in Treasury	0
3030-Miscellaneous Paid-In Capital	0
3035-Installments Received on Capital Stock	0
3040-Appropriated Retained Earnings	0
3045-Unappropriated Retained Earnings	2,094,661
3046-Balance Transferred From Income	(43,803)
3047-Appropriations of Retained Earnings - Current Period	0
3048-Dividends Payable-Preference Shares	0
3049-Dividends Payable-Common Shares	(600,000)
3055-Adjustment to Retained Earnings	0
3065-Unappropriated Undistributed Subsidiary Earnings	0
1850-Shareholders' Equity Total	**6,744,234**

Total Liabilities & Shareholder's Equity	**22,794,475**

Balance Sheet Total	0

Lakefront Utilities Inc.
2011 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(5,546,242)
4010-Commercial Energy Sales GS<50 & USL	(2,687,106)
4015-Industrial Energy Sales/Intermediate	(1,393,795)
4020-Energy Sales to Large Users	0
4025-Street Lighting Energy Sales	(87,034)
4030-Sentinel Energy Sales	(5,681)
4035-General Energy Sales GS> 50- 2999	(8,732,855)
4040-Other Energy Sales to Public Authorities	0
4045-Energy Sales to Railroads and Railways	0
4050-Revenue Adjustment	0
4055-Energy Sales for Resale	0
4060-Interdepartmental Energy Sales	0
4062-WMS	(1,704,674)
4064-Billed WMS-One Time	0
4066-NS	(1,309,278)
4068-CS	(1,031,246)
4075-LV Charges	(310,741)
3000-Sales of Electricity Total	**(22,808,653)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(4,004,517)
4082-RS Rev	(10,015)
4084-Serv Tx Requests	(4,560)
4090-Electric Services Incidental to Energy Sales	0
3050-Revenues From Services - Distirbution Total	**(4,019,092)**
3100-Other Operating Revenues	
4205-Interdepartmental Rents	(51,600)
4210-Rent from Electric Property	(56,500)
4215-Other Utility Operating Income	0
4220-Other Electric Revenues	0
4225-Late Payment Charges	(63,140)
4230-Sales of Water and Water Power	0
4235-Miscellaneous Service Revenues	(127,000)
4240-Provision for Rate Refunds	0
4245-Government Assistance Directly Credited to Income	0
3100-Other Operating Revenues Total	**(298,240)**

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	0
4365-Gains from Disposition of Allowances for Emission	0
4370-Losses from Disposition of Allowances for Emission	0
4375-Revenues from Non-Utility Operations	0
4380-Expenses of Non-Utility Operations	0
4385-Expenses of Non-Utility Operations	0
4390-Miscellaneous Non-Operating Income	0
4395-Rate-Payer Benefit Including Interest	0
4398-Foreign Exchange Gains and Losses, Including Amortization	0
3150-Other Income & Deductions Total	**0**

3200-Investment Income	
4405-Interest and Dividend Income	(28,500)
4415-Equity in Earnings of Subsidiary Companies	0
3200-Investment Income Total	**(28,500)**

3350-Power Supply Expenses	
4705-Power Purchased	18,452,714
4708-WMS	1,704,674
4710-Cost of Power Adjustments	0
4712-Charges - One - Time	0
4714-NW	1,309,278
4715-System Control and Load Dispatching	0
4716-CCN	1,031,246
4720-Other Expenses	0
4725-Competition Transition Expense	0
4730-Rural Rate Assistance Expense	0
4750-LV Charges	310,741
3350-Power Supply Expenses Total	**22,808,653**

3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	188,943
5010-Load Dispatching	0
5012-Station Buildings and Fixtures Expense	0
5014-Transformer Station Equipment - Operation Labour	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0
5016-Distribution Station Equipment - Operation Labour	2,523
5017-Distribution Station Equipment - Operation Supplies and Expenses	29,642
5020-Overhead Distribution Lines and Feeders - Operation Labour	178,880
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	122,488
5030-Overhead Subtransmission Feeders - Operation	0
5035-Overhead Distribution Transformers - Operation	0
5040-Underground Distribution Lines and Feeders - Operation Labour	18,023
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	19,352
5050-Underground Subtransmission Feeders - Operation	0
5055-Underground Distribution Transformers - Operation	0
5060-Street Lighting and Signal System Expense	0
5065-Meter Expense	15,202
5070-Customer Premises - Operation Labour	0
5075-Customer Premises - Materials and Expenses	0
5085-Miscellaneous Distribution Expense	4,556
5090-Underground Distribution Lines and Feeders - Rental Paid	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0
5096-Other Rent	0
3500-Distribution Expenses - Operation Total	**579,609**

3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	34,875
5110-Maintenance of Structures	0
5112-Maintenance of Transformer Station Equipment	0
5114-Mtaint Dist Stn Equip	0
5120-Maintenance of Poles, Towers and Fixtures	40,570
5125-Maintenance of Overhead Conductors and Devices	0
5130-Maintenance of Overhead Services	0
5135-Overhead Distribution Lines and Feeders - Right of Way	44,863
5145-Maintenance of Underground Conduit	0
5150-Maintenance of Underground Conductors and Devices	0
5155-Maintenance of Underground Services	8,960
5160-Maintenance of Line Transformers	35,674
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	141,277
5178-Customer Installations Expenses - Leased Property	0
5195-Maintenance of Other Installations on Customer Premises	0
3550-Distribution Expenses - Maintenance Total	**306,219**

3650-Billing and Collecting	
5305-Supervision	0
5310-Meter Reading Expense	134,191
5315-Customer Billing	130,575
5320-Collecting	106,842
5325-Collecting - Cash Over and Short	0
5330-Collection Charges	4,050
5335-Bad Debt Expense	21,888
5340-Miscellaneous Customer Accounts Expenses	103,995
3650-Billing and Collecting Total	**501,542**

3700-Community Relations	
5405-Supervision	0
5410-Community Relations - Sundry	13,927
5415-Energy Conservation	0
5420-Community Safety Program	0
5425-Miscellaneous Customer Service and Informational Expenses	0
3700-Community Relations Total	**13,927**

3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	47,906
5610-Management Salaries and Expenses	449,700
5615-General Administrative Salaries and Expenses	93,985
5620-Office Supplies and Expenses	102,802
5625-Administrative Expense Transferred-Credit	0
5630-Outside Services Employed	101,364
5635-Property Insurance	27,878
5640-Injuries and Damages	60,558
5645-Employee Pensions and Benefits	0
5650-Franchise Requirements	0
5655-Regulatory Expenses	85,546
5660-General Advertising Expenses	2,583
5665-Miscellaneous Expenses	830
5670-Rent	0
5675-Maintenance of General Plant	33,370
5680-Electrical Safety Authority Fees	41,306
5685-Independent Market Operator Fees and Penalties	0
5695-OM&A Contra Account	0
3800-Administrative and General Expenses Total	**1,047,829**

3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	1,124,562
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	**1,124,562**

3900-Interest Expense	
6005-Interest on Long Term Debt	427,000
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	0
6035-Other Interest Expense	308,560
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	**735,560**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	48,099
3950-Taxes Other Than Income Taxes Total	**48,099**
4000-Income Taxes	
6110-Income Taxes	32,287
6115-Provision for Future Income Taxes	0
4000-Income Taxes Total	**32,287**
4100-Extraordinary & Other Items	
6205-Donations	0
6210-Life Insurance	0
6215-Penalties	0
6225-Other Deductions	0
4100-Extraordinary & Other Items Total	**0**
Net Income - (Gain)/Loss	**43,803**

APPENDIX F COPY OF Lakefront Utilities Inc. 2012 PRO FORMA STATEMENTS

Lakefront Utilities Inc.
2012 BALANCE SHEET

Account Description	Total
1050-Current Assets	
1005-Cash	3,211,955
1010-Cash Advances and Working Funds	0
1020-Interest Special Deposits	0
1030-Dividend Special Deposits	0
1040-Other Special Deposits	0
1060-Term Deposits	0
1070-Current Investments	0
1100-Customer Accounts Receivable	1,827,151
1102-Accounts Receivable - Services	0
1104-Accounts Receivable - Recoverable Work	0
1105-Accounts Receivable - Merchandise, Jobbing, etc.	90,000
1110-Other Accounts Receivable	20,000
1120-Accrued Utility Revenues	3,600,000
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(40,000)
1140-Interest and Dividends Receivable	0
1150-Rents Receivable	0
1170-Notes Receivable	0
1180-Prepayments	52,000
1190-Miscellaneous Current and Accrued Assets	700
1200-Accounts Receivable from Associated Companies	0
1210-Notes Receivable from Associated Companies	0
1050-Current Assets Total	**8,761,806**

1100-Inventory	
1305-Fuel Stock	0
1330-Plant Materials and Operating Supplies	241,000
1340-Merchandise	0
1350-Other Material and Supplies	0
1100-Inventory Total	**241,000**

1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	0
1408-Long Term Receivable - Street Lighting Transfer	0
1410-Other Special or Collateral Funds	0
1415-Sinking Funds	0
1425-Unamortized Debt Expense	0
1445-Unamortized Discount on Long-Term Debt--Debit	0
1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	0
1460-Other Non-Current Assets	0
1465-O.M.E.R.S. Past Service Costs	0
1470-Past Service Costs - Employee Future Benefits	0
1475-Past Service Costs -Other Pension Plans	0
1480-Portfolio Investments - Associated Companies	0
1485-Investment In Subsidiary Companies - Significant Influence	0
1490-Investment in Subsidiary Companies	0
1150-Non-Current Assets Total	**0**

1200-Other Assets and Deferred Charges	
1505-Unrecovered Plant and Regulatory Study Costs	0
1508-Other Regulatory Assets	9,242
1510-Preliminary Survey and Investigation Charges	0
1515-Emission Allowance Inventory	0
1516-Emission Allowance Withheld	0
1518-RCVA Retail	44,297
1525-Miscellaneous Deferred Debits & 1521 SPC	58,288
1530-Deferred Losses from Disposition of Utility Plant	0
1540-Deferred Losses from Disposition of Utility Plant	0
1545-Development Charge Deposits/ Receivables	0
1548-RCVA - Service Transaction Request (STR)	40,408
1550-LV Charges - Variance	(234,703)
1555-Smart Meters Recovery	0
1556-Smart Meters OM & A	76,723
1562-Deferred PILs	(97,488)
1563-Deferred PILs - Contra	97,488
1565-C & DM Costs	0
1566-C & DM Costs Contra	0
1570-Qualifying Transition Costs	0
1571-Pre Market CofP Variance	0
1572-Extraordinary Event Losses	0
1574-Deferred Rate Impact Amounts	0
1580-RSVA - Wholesale Market Services	(325,368)
1582-RSVA - One-Time	17,991
1584-RSVA - Network Charges	28,722
1586-RSVA - Connection Charges	42,157
1588-RSVA - Commodity (Power)	73,808
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	0
1592-PILs and Tax Variance for 2006 & Subsequent Years	0
1595-Disposition and Recovery of Regulatory Balances	226,737
1200-Other Assets and Deferred Charges Total	**58,301**

1450-Distribution Plant	
1610-Intangible Assets	0
1805-Land	219,284
1806-Land Rights	0
1808-Buildings and Fixtures	1,369,216
1810-Leasehold Improvements	0
1815-Transformer Station Equipment - Normally Primary above 50 kV	0
1820-Distribution Station Equipment - Normally Primary below 50 kV	2,762,235
1825-Storage Battery Equipment	0
1830-Poles, Towers and Fixtures	1,797,311
1835-Overhead Conductors and Devices	4,422,754
1840-Underground Conduit	1,388,943
1845-Underground Conductors and Devices	3,066,154
1850-Line Transformers	5,543,049
1855-Services	623,529
1860-Meters	2,097,905
1865-Other Installations on Customer's Premises	0
1450-Distribution Plant Total	**23,290,380**

1500-General Plant	
1905-Land	0
1906-Land Rights	0
1908-Buildings and Fixtures	0
1910-Leasehold Improvements	0
1915-Office Furniture and Equipment	107,026
1920-Computer Equipment - Hardware	231,199
1925-Computer Software	612,582
1930-Transportation Equipment	814,705
1935-Stores Equipment	0
1940-Tools, Shop and Garage Equipment	627,730
1945-Measurement and Testing Equipment	18,712
1950-Power Operated Equipment	0
1955-Communication Equipment	0
1960-Miscellaneous Equipment	0
1970-Load Management Controls - Customer Premises	0
1975-Load Management Controls - Utility Premises	0
1980-System Supervisory Equipment	0
1985-Sentinel Lighting Rentals	0
1990-Other Tangible Property	0
1995-Contributions and Grants	(2,357,659)
1500-General Plant Total	**54,294**

1550-Other Capital Assets	
2005-Property Under Capital Leases	0
2010-Electric Plant Purchased or Sold	0
2020-Experimental Electric Plant Unclassified	0
2030-Electric Plant and Equipment Leased to Others	0
2040-Electric Plant Held for Future Use	0
2050-Completed Construction Not Classified--Electric	0
2055-Construction Work in Progress--Electric	0
2060-Electric Plant Acquisition Adjustment	0
2065-Other Electric Plant Adjustment	0
2070-Other Utility Plant	0
2075-Non-Utility Property Owned or Under Capital Lease	0
1550-Other Capital Assets Total	**0**

1600-Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(9,103,379)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	0
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	0
2160-Accumulated Amortization of Other Utility Plant	0
2180-Accumulated Amortization of Non-Utility Property	0
1600-Accumulated Amortization Total	**(9,103,379)**

Total Assets	**23,302,401**

1650-Current Liabilities	
2205-Accounts Payable	2,350,000
2208-Customer Credit Balances	123,410
2210-Current Portion of Customer Deposits	0
2215-Dividends Declared	0
2220-Miscellaneous Current and Accrued Liabilities	300,000
2225-Notes and Loans Payable	0
2240-Accounts Payable to Associated Companies	0
2242-Notes Payable to Associated Companies	0
2250-Debt Retirement Charges (DRC) Payable	117,000
2252-Transmission Charges Payable	0
2254-Electric Safety Authority Fees Payable	0
2256-Independent Market Operator Fees and Penalties Payable	0
2260-Current Portion of Long Term Debt	0
2262-Ontario Hydro Debt - Current Portion	0
2264-Pensions and Employee Benefits - Current Portion	0
2268-Accrued Interest on Long Term Debt	0
2270-Matured Long Term Debt	0
2272-Matured Interest on Long Term Debt	0
2285-Obligations Under Capital Leases--Current	0
2290-Commodity Taxes	100,000
2292-Payroll Deductions / Expenses Payable	0
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	(10,000)
2296-Future Income Taxes - Current	0
1650-Current Liabilities Total	**2,980,410**

1700-Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	0
2306-Employee Future Benefits	304,712
2308-Other Pensions - Past Service Liability	0
2310-Vested Sick Leave Liability	0
2315-Accumulated Provision for Rate Refunds	0
2320-Other Miscellaneous Non-Current Liabilities	0
2325-Obligations Under Capital Lease--Non-Current	0
2330-Devolpment Charge Fund	0
2335-Long Term Customer Deposits	0
2340-Collateral Funds Liability	0
2345-Unamortized Premium on Long Term Debt	0
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	0
2350-Future Income Tax - Non-Current	0
2405-Other Regulatory Liabilities	(60,000)
2410-Deferred Gains From Disposition of Utility Plant	0
2415-Unamortized Gain on Reacquired Debt	0
2425-Other Deferred Credits	0
2435-Accrued Rate-Payer Benefit	0
1700-Non-Current Liabilities Total	**244,712**

1800-Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	5,800,000
2510-Debenture Advances	0
2515-Required Bonds	0
2520-Other Long Term Debt	7,000,000
2525-Term Bank Loans - Long Term Portion	0
2530-Ontario Hydro Debt Outstanding - Long Term Portion	0
2550-Advances from Associated Companies	0
1800-Long-Term Debt Total	**12,800,000**

1850-Shareholders' Equity	
3005-Common Shares Issued	5,293,376
3008-Preference Shares Issued	0
3010-Contributed Surplus	0
3020-Donations Received	0
3022-Devolpment Charges Transferred to Equity	0
3026-Capital Stock Held in Treasury	0
3030-Miscellaneous Paid-In Capital	0
3035-Installments Received on Capital Stock	0
3040-Appropriated Retained Earnings	0
3045-Unappropriated Retained Earnings	2,039,282
3046-Balance Transferred From Income	544,621
3047-Appropriations of Retained Earnings - Current Period	0
3048-Dividends Payable-Preference Shares	0
3049-Dividends Payable-Common Shares	(600,000)
3055-Adjustment to Retained Earnings	0
3065-Unappropriated Undistributed Subsidiary Earnings	0
1850-Shareholders' Equity Total	**7,277,279**

Total Liabilities & Shareholder's Equity	**23,302,401**

Balance Sheet Total	(0)

Lakefront Utilities Inc.
2012 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(5,597,222)
4010-Commercial Energy Sales GS<50 & USL	(2,742,537)
4015-Industrial Energy Sales/Intermediate	(1,393,795)
4020-Energy Sales to Large Users	0
4025-Street Lighting Energy Sales	(87,807)
4030-Sentinel Energy Sales	(5,665)
4035-General Energy Sales GS> 50- 2999	(8,774,591)
4040-Other Energy Sales to Public Authorities	0
4045-Energy Sales to Railroads and Railways	0
4050-Revenue Adjustment	0
4055-Energy Sales for Resale	0
4060-Interdepartmental Energy Sales	0
4062-WMS	(1,718,234)
4064-Billed WMS-One Time	0
4066-NS	(1,358,005)
4068-CS	(1,065,063)
4075-LV Charges	(313,691)
3000-Sales of Electricity Total	**(23,056,611)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(4,791,063)
4082-RS Rev	(9,985)
4084-Serv Tx Requests	(4,015)
4090-Electric Services Incidental to Energy Sales	0
3050-Revenues From Services - Distirbution Total	**(4,805,063)**

3100-Other Operating Revenues	
4205-Interdepartmental Rents	(51,600)
4210-Rent from Electric Property	(56,400)
4215-Other Utility Operating Income	0
4220-Other Electric Revenues	0
4225-Late Payment Charges	(63,140)
4230-Sales of Water and Water Power	0
4235-Miscellaneous Service Revenues	(126,500)
4240-Provision for Rate Refunds	0
4245-Government Assistance Directly Credited to Income	0
3100-Other Operating Revenues Total	**(297,640)**

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	0
4365-Gains from Disposition of Allowances for Emission	0
4370-Losses from Disposition of Allowances for Emission	0
4375-Revenues from Non-Utility Operations	0
4380-Expenses of Non-Utility Operations	0
4385-Expenses of Non-Utility Operations	0
4390-Miscellaneous Non-Operating Income	0
4395-Rate-Payer Benefit Including Interest	0
4398-Foreign Exchange Gains and Losses, Including Amortization	0
3150-Other Income & Deductions Total	**0**

3200-Investment Income	
4405-Interest and Dividend Income	(28,500)
4415-Equity in Earnings of Subsidiary Companies	0
3200-Investment Income Total	**(28,500)**

3350-Power Supply Expenses	
4705-Power Purchased	18,601,618
4708-WMS	1,718,234
4710-Cost of Power Adjustments	0
4712-Charges - One - Time	0
4714-NW	1,358,005
4715-System Control and Load Dispatching	0
4716-CCN	1,065,063
4720-Other Expenses	0
4725-Competition Transition Expense	0
4730-Rural Rate Assistance Expense	0
4750-LV Charges	313,691
3350-Power Supply Expenses Total	**23,056,611**

3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	323,678
5010-Load Dispatching	0
5012-Station Buildings and Fixtures Expense	0
5014-Transformer Station Equipment - Operation Labour	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0
5016-Distribution Station Equipment - Operation Labour	2,599
5017-Distribution Station Equipment - Operation Supplies and Expenses	35,331
5020-Overhead Distribution Lines and Feeders - Operation Labour	309,975
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	126,163
5030-Overhead Subtransmission Feeders - Operation	0
5035-Overhead Distribution Transformers - Operation	631
5040-Underground Distribution Lines and Feeders - Operation Labour	25,000
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	19,933
5050-Underground Subtransmission Feeders - Operation	0
5055-Underground Distribution Transformers - Operation	0
5060-Street Lighting and Signal System Expense	0
5065-Meter Expense	31,316
5070-Customer Premises - Operation Labour	0
5075-Customer Premises - Materials and Expenses	77
5085-Miscellaneous Distribution Expense	4,693
5090-Underground Distribution Lines and Feeders - Rental Paid	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0
5096-Other Rent	0
3500-Distribution Expenses - Operation Total	**879,396**

3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	52,313
5110-Maintenance of Structures	0
5112-Maintenance of Transformer Station Equipment	0
5114-Mtaint Dist Stn Equip	0
5120-Maintenance of Poles, Towers and Fixtures	41,787
5125-Maintenance of Overhead Conductors and Devices	10,000
5130-Maintenance of Overhead Services	3,000
5135-Overhead Distribution Lines and Feeders - Right of Way	45,054
5145-Maintenance of Underground Conduit	0
5150-Maintenance of Underground Conductors and Devices	0
5155-Maintenance of Underground Services	9,229
5160-Maintenance of Line Transformers	36,139
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	194,264
5178-Customer Installations Expenses - Leased Property	0
5195-Maintenance of Other Installations on Customer Premises	0
3550-Distribution Expenses - Maintenance Total	**391,786**

3650-Billing and Collecting	
5305-Supervision	0
5310-Meter Reading Expense	17,192
5315-Customer Billing	131,000
5320-Collecting	130,277
5325-Collecting - Cash Over and Short	0
5330-Collection Charges	4,172
5335-Bad Debt Expense	22,545
5340-Miscellaneous Customer Accounts Expenses	195,112
3650-Billing and Collecting Total	**500,298**

3700-Community Relations	
5405-Supervision	0
5410-Community Relations - Sundry	14,345
5415-Energy Conservation	0
5420-Community Safety Program	0
5425-Miscellaneous Customer Service and Informational Expenses	0
3700-Community Relations Total	**14,345**

3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	49,343
5610-Management Salaries and Expenses	494,916
5615-General Administrative Salaries and Expenses	143,854
5620-Office Supplies and Expenses	105,886
5625-Administrative Expense Transferred-Credit	0
5630-Outside Services Employed	155,405
5635-Property Insurance	28,715
5640-Injuries and Damages	62,375
5645-Employee Pensions and Benefits	0
5650-Franchise Requirements	0
5655-Regulatory Expenses	103,562
5660-General Advertising Expenses	4,660
5665-Miscellaneous Expenses	855
5670-Rent	0
5675-Maintenance of General Plant	84,371
5680-Electrical Safety Authority Fees	47,546
5685-Independent Market Operator Fees and Penalties	0
5695-OM&A Contra Account	0
3800-Administrative and General Expenses Total	**1,281,489**

3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	816,209
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	**816,209**
3900-Interest Expense	
6005-Interest on Long Term Debt	372,400
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	0
6035-Other Interest Expense	245,920
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	**618,320**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	49,542
3950-Taxes Other Than Income Taxes Total	**49,542**
4000-Income Taxes	
6110-Income Taxes	35,198
6115-Provision for Future Income Taxes	0
4000-Income Taxes Total	**35,198**
4100-Extraordinary & Other Items	
6205-Donations	0
6210-Life Insurance	0
6215-Penalties	0
6225-Other Deductions	0
4100-Extraordinary & Other Items Total	**0**
Net Income - (Gain)/Loss	**(544,621)**

RECONCILIATION BETWEEN PRO FORMA STATEMENTS AND REVENUE DEFICIENCY STATEMENTS

LUI advises that because the 2010 Audited Financial Statements do not vary from the regulatory financial results filed in this Application, a reconciliation between the financial statements and financial results filed has not been provided. However, as a result of differences between deemed and actual interest expense, non utility revenue and expenses, the following chart provides a reconciliation for 2012 Pro Forma Statements and the Revenue Deficiency Statements.

Deemed Net Income	671,593.20
Interest Deemed	491,347.89
Actual Interest	618,320.00
Difference	- 126,972.11
Add back difference	544,621.10
Actual FS Net Income	544,621.10

MATERIALITY THRESHOLD

LUI has chosen to use a materiality threshold of $50,000 throughout this Cost of Service Application. In the Board's June 22, 2011 Filing Requirements, a default threshold of $50,000 was prescribed for those distributors with a distribution revenue requirement less than or equal to $10 million. Since LUI's 2008 Cost of Service Rate Application revenue requirement is under $10 million and the revenue requirement for the Test Year 2012 is also under $10 million, the default threshold of $50,000 seemed most appropriate for use in this Application. However you will note that LUI has made every effort to ensure that all variances and analysis is prepared, even for variances under $50,000 in order to assist in analyzing LUI's Rate Application.

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RATE BASE OVERVIEW

Lakefront Utilities Inc. (LUI) is an LDC in the Province of Ontario that is responsible for providing all regulated electricity distribution services to approximately 9,800 residential and business customers in the Town of Cobourg and Village of Colborne.

LUI utilizes the OEB USofA for recording and grouping its assets. LUI provided a summary of its historical rate base calculations for the years 2008 Board Approved, 2008 Actual, 2009 to 2010 Actual, as well as 2011 Bridge Year and 2012 Test Year in the Table below.

The rate base used for the purpose of calculating the revenue requirement used in this Application follows an average of the balances at the beginning and the end of the 2012 Test Year, plus a working capital allowance, which is 15% of the sum of the cost of power and controllable expenses. The 15% allowance is consistent with the June 22, 2011 filing requirements.

The net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. LUI does not have any non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses. LUI has calculated its 2012 Test Year Rate Base as $`.

LUI has prepared this Rate Application using MIFRS for the 2012 Test Year in all circumstances, unless otherwise specifically stated. LUI has also added a comparison between CGAAP and MIFRS where required to identify differences between the two.

LUI uses the following accounts (with written descriptions) in the calculation of its net fixed assets:

1805 – Land

This account is used to record the cost of land held by LUI, used in connection with power distribution.

1806 - Land Rights

This account is used to record the cost of rights, interests, easements and privileges held by the utility in land owned by others.

1808 - Buildings & Fixtures

This account is used to record the costs of buildings owned by LUI used in connection with distribution operations. In LUI's financial system, the costs are separated for each building by asset type and asset number.

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 LUI's distribution stations, used for the purpose of stepping down to distribution voltages. In LUI's financial system, costs are separated for each distribution station by asset type and asset number. The detail of stations has been tracked in such a manner that an accurate record of their age, cost, location and voltage characteristics are evident.

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. LUI has approximately 2,787 poles within its service territory.

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. LUI has approximately 95 kilometers of overhead line within its service territory.

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.
In LUI's financial system, costs are recorded by annual additions and also segregated by overhead and underground.

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. LUI's records are maintained providing information separately for underground and overhead services.

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. (excluding Smart Meters).
In LUI's metering sub-system, meters are identified by type, capacity and function.
LUI is requesting the disposal of the Smart Meter variance accounts in this Cost of Service Rate Application and therefore wishes to include Smart Meters into this account in 2012.

1908 - Buildings and Fixtures

This account includes the costs of buildings and fixtures used for utility purposes owned by LUI. In LUI's financial system, the costs are separated for each building by asset type and asset number.

1915 – Office Furniture & Equipment

This account contains the cost of general office furniture and equipment. In LUI's financial system, the items in this account are considered unique, identifiable assets.

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. In LUI's financial systems, the items in this account are considered unique, identifiable assets.

1925 – Computer Software

This account contains the installed costs of all computer software purchased or developed in-house. In LUI's financial system, the items in this account are considered unique, identifiable assets.

1930 – Transportation Equipment

This account contains the costs of all vehicles owned by LUI, 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 LUI's warehouse for shipping, receiving, handling and storage of materials and supplies. In LUI's financial system, the items in this account are considered unique and identifiable assets.

1940 – Tools, Shop and Garage Equipment

This account contains the cost of all tools and non-power equipment purchased by LUI in accordance with the example items from the Accounting Procedures Handbook (APH) issued by the OEB. In LUI's financial system, the items in this account are considered unique and identifiable assets.

1945 – Measurement and Testing Equipment

This account contains the cost of all measurement and testing equipment purchased by LUI in accordance with the example items from the Accounting Procedures Handbook (APH) issued by the OEB. In LUI's financial system, the items in this account are considered unique and identifiable assets.

1995 – Contributions and Grants

This account includes amount 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.) In LUI's financial system, separate records are kept as to the identity of the project and the contributor.

RATE BASE

Rate Base Overview

The rate base used for the purpose of calculating the revenue requirement used in this Application uses an average of the net book value of fixed assets at the beginning and the end of the 2012 Test Year, plus a working capital allowance, which is 15% of the sum of the cost of power and controllable expenses in the test year.

The net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. LUI's rate base calculation excludes any non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses. LUI has provided its rate base calculations for the years 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year and 2012 Test Year in Table 2-0 below.

Table 2-0A Summary of Rate Base (MIFRS)

Description	2008 OEB Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Gross Fixed Assets	20,351,477	20,383,574	17,756,449	18,318,391	21,245,673	23,344,673
Accumulated Depreciation	9,297,933	9,640,718	6,903,141	7,412,314	8,287,170	9,103,379
Net Book Value	11,053,544	10,742,856	10,853,308	10,906,077	12,958,503	14,241,294
Average Net Book Value	11,006,545	10,539,841	10,798,082	10,879,692	11,932,290	13,599,899
Working Capital	22,710,874	21,670,175	21,492,619	22,910,816	25,305,878	26,173,467
Working Capital Allowance (15%)	3,406,631	3,250,526	3,223,893	3,436,622	3,795,882	3,926,020
Rate Base	14,413,176	13,790,367	14,021,975	14,316,315	15,728,172	17,525,919

Table 2-0B Summary of Rate Base (CGAAP)

Description	2008 OEB Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Gross Fixed Assets	20,351,477	20,383,574	17,756,449	18,318,391	21,245,673	23,344,673
Accumulated Depreciation	9,297,933	9,640,718	6,903,141	7,412,314	8,287,170	9,541,584
Net Book Value	11,053,544	10,742,856	10,853,308	10,906,077	12,958,503	13,803,089
Average Net Book Value	11,006,545	10,539,841	10,798,082	10,879,692	11,932,290	13,380,796
Working Capital	22,710,874	21,670,175	21,492,619	22,910,816	25,305,878	26,173,466
Working Capital Allowance	3,406,631	3,250,526	3,223,893	3,436,622	3,795,882	3,926,020
Rate Base	14,413,176	13,790,367	14,021,975	14,316,315	15,728,172	17,306,816

LUI's capital investment in distribution plant has been steadily increasing since 2008. Due to LUI's conversion of its 4kV to 27.6kV, LUI will need to replace existing substations, and infrastructure that is over 40 and 60 years old.

LUI has provided a summary of its cost of power and controllable expenses used in calculating working capital for the period 2008 Actual to 2010 Actual, including the 2008 Board Approved, 2011 Bridge Year and 2012 Test Year in Table 2-1, below.

Table 2-1A Summary of Working Capital Calculation (MIFRS)

Description	2008 OEB Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Cost of Power	20,560,245	19,742,668	19,583,913	20,764,427	22,808,653	23,056,611
Operations	620,871	617,177	505,675	415,821	579,609	879,396
Maintenance	104,107	77,337	139,615	225,312	306,219	391,786
Billing & Collecting	428,844	440,285	407,715	425,479	501,542	500,298
Community Relations	19,767	8,053	(4,705)	13,355	13,927	14,345
Administration & General Expense	921,831	741,765	806,924	1,019,724	1,047,829	1,281,489
Property Taxes	55,209	42,890	53,482	46,698	48,099	49,542
Working Capital	22,710,874	21,670,175	21,492,619	22,910,816	25,305,878	26,173,467

Table 2-1B Summary of Working Capital Calculation (CGAAP)

Description	2008 OEB Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Cost of Power	20,560,245	19,742,668	19,583,913	20,764,427	22,808,653	23,056,611
Operations	620,871	617,177	505,675	415,821	579,609	879,396
Maintenance	104,107	77,337	139,615	225,312	306,219	391,786
Billing & Collecting	428,844	440,285	407,715	425,479	501,542	500,298
Community Relations	19,767	8,053	(4,705)	13,355	13,927	14,345
Administration & General Expense	921,831	741,765	806,924	1,019,724	1,047,829	1,281,488
Property Taxes	55,209	42,890	53,482	46,698	48,099	49,542
Working Capital	22,710,874	21,670,175	21,492,619	22,910,816	25,305,878	26,173,466

The changes in working capital are primarily attributed to the annual changes in Cost of Power resulting from growth, weather and changes in the market price of electricity and increases in OM&A expenditures to service the growth such as staffing requirements, locate costs, meter reading, postage, etc. LUI has not completed a lead-lag study pending OEB direction. The working capital allowance is based on 15% of cost of power and controllable expenses in accordance with the Filing Requirements and consistent with OEB Decisions on other distribution rate applications where a utility specific lead-lag study had not been completed.

In support of its rate base calculation, LUI has included details of its Gross Assets, Accumulated Depreciation, Working Capital and Fixed Asset Continuity Schedules for 2008 Actual to 2012 Test Year as required in the Filing Requirements.

Budget Process

In managing its distribution system assets, LUI's main objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, safety, and customer service expectations. LUI applies a planning process for all its capital additions and is committed to providing our customers with an economical, safe, reliable supply of electricity and helping the Town of Cobourg and Village of Colborne become the most energy efficient communities in Ontario. As a result of this process LUI is of the opinion that capital spending decisions are in line with best practices in the industry. LUI's Asset Management Plan, which

sets out LUI's processes for determining the necessary distribution system investments, accompanies this Exhibit as Appendix A.

The Capital Budget process at LUI is an integral planning tool and ensures that appropriate resources are available to maintain and grow its capital infrastructure. It is the responsibility of each department to contribute in the preparation of the Capital and Operating budgets with the assistance of the Finance department. The responsibility of the Finance department is to coordinate the capital budget and forecast process and present a preliminary Capital budget to the President for approval. Once the preliminary Capital budget and long range forecast has been approved by the President, it is presented to the Board of Directors for approval.

Once the Board of Directors approve the annual budget, the budget amounts do not change but rather provide a plan against which actual results may be evaluated.

Capital Budget

LUI's capital budget is segregated into the following categories:

- Asset Management Capital Expenditures
- Developer-Driven (Growth related) Capital Expenditures
- Municipal Driven Capital Expenditures
- Other Capital Expenditures

Asset management capital expenditures are capital projects relating to LUI's existing and new capital infrastructure and/or projects identified through regulatory and legislative requirements. A primary capital focus has been its voltage conversion program from 4kV to 27.6kV whose ultimate goal is to reduce system losses and contribute to the CDM mandate of the Province. Developer-driven capital expenditures are directly related to growth and are partially funded through Capital Contributions. Municipal-driven capital expenditures are also related to growth or other municipal initiatives, which drive road, water and sewer requirements and are partially funded through Capital Contributions, 50% of labour and labour

saving devices, in accordance with the Municipal Act. Other Capital Expenditures are general assets relating to Leasehold Building Improvements, Office Furniture and Equipment, Communications Equipment, Computer Hardware and Software, System Supervisory Equipment, Vehicles and Miscellaneous Tools and Equipment.

This Application incorporates LUI's 2011 Bridge Year & 2012 Test Year Capital and Operating, Maintenance & Administration Budgets used in determining the revenue requirement to bring these plans to fruition.

LUI's Capital Budget process is based on:

Customer Demand

These are projects that LUI undertakes to meet customer obligations in accordance with the OEB's Distribution System Code (the "DSC") and LUI's Conditions of Service. Activities include connecting new residential and general service customers, constructing distribution plant to connect new subdivisions and relocating system plant equipment for roadway reconstruction work. LUI contributes to the cost of these projects using the economic evaluation methodology in accordance with the DSC and the provisions of its Conditions of Service for system expansions to determine the level of capital contribution.

Replacement

Replacement projects are completed when it has been determined through proper condition assessment that assets have reached their end of useful life. LUI completes visual inspections of its plant and performs predictive testing on certain assets where such testing is available, and replaces assets based on inspection and testing results as warranted. In some cases the projects involve spot replacement of assets; in other cases, the projects involve complete asset replacement within a geographic area. New assets require less maintenance, deliver better reliability and reduce safety risks to the general public.

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 and transformers or voltage conversion projects. These projects are not customer-specific, but rather, they benefit many customers.

Regulatory Requirements

These projects are 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 & Infrastructure or the Ministry of Environment.

Smart Meters

In June of 2004, the Minister of Energy issued a Directive under Section 27.1 of the *Ontario Energy Board Act,* 1998 which required the Board to develop and, upon approval by the Minister of Energy, implement a plan to achieve the government's objectives for the deployment of smart electricity meters.

The provincial Smart Meter Initiative would stem from this Directive and all Local Distribution Companies (LDCs) in Ontario would be heavily involved in creating a conservation culture in Ontario and making the Province a North American leader in energy efficiency.

The provincial initiative mandated the installation of a smart electricity meter in every Ontario home by December 31, 2010. The underlying premise behind the mandate to install these meters was to educate customers on their consumption habits and to implement new rate structures that encouraged load shifting and conservation of energy, thereby reducing the requirement for increased power generation capabilities.

This was an enormous undertaking for all LDCs; a project that took months of planning and carefully managed execution. To accommodate the needs of the Ministry of Energy and Infrastructure, LUI installed approximately 9,500 Smart Meters to fulfill its requirements for the mandate.

Smart Grid

LUI believes that Smart Grid initiatives within our distribution service territory need to be undertaken incrementally and form part of a realistic and sensible distribution system improvement program. At this juncture, Smart Grid activities are likely to form part of our future capital distribution system replacement plan. A detailed summary of incremental expenditures associated with specific Smart Grid activities and projects is currently being compiled.

Substations

Substation investments are undertaken to improve or maintain reliability to large numbers of customers and to maintain security and safety at the substations. LUI has been converting aging 4.6kV to 27.6kV as required for reliability, which in addition to the construction of new 27.6kV feeders, will lead to a reduction in the number of distribution stations and improved efficiency in the delivery of electricity. LUI has initiated the studies for a new 27.6kV substation with an in service date of 2015.

Customer Connections and Metering

Capital expenditures include meter installations, meter upgrades, and the capital components of wholesale and retail meter verification activities. As of July 31, 2011 LUI has completed 99.7% of the deployment of Smart Meters as approved by Ontario Regulation 427/06. Smart Meter capital is currently recorded in the smart meter variance account 1555. LUI is proposing the disposition on its smart meter variance accounts in this Application.

General Plant Capital Projects

General plant capital projects are also been categorized into project pools. Each pool generally by OEB USofA category has identified within it the specific focus of the capital requirement and include:

- Land, Buildings and Leasehold Improvements (USoA 1905, 1908, 1910)
- Office Furniture & Equipment (USoA 1915)
- Computer Hardware & Software(USoA 1920, 1925)
- Transportation/Vehicles Equipment (USoA 1930)
- Stores Equipment, Tools and Measuring Equipment (USoA 1935, 1940, 1945)
- Communication Equipment (USoA 1955)
- System Supervisory Equipment (USoA 1980)
- Other Tangible Property (USoA 1990)

LUI follows Generally Accepted Accounting Principles, in particular the CICA Handbook Section 3060, Capital Assets as well as the guidelines as set out in the OEB Accounting Procedure Handbook.

LUI does not capitalize interest on funds used during construction as capital projects are budgeted for and completed in the fiscal year. In addition, LUI does not capitalize, through internal cost allocations, any indirect administrative support costs such as Finance or Facilities. LUI does not have a Corporate Services Department.

LUI's Distribution System

LUI owns and operates the electricity distribution system in the Town of Cobourg and Village of Colborne serving more than 22,000 residential and business customers. LUI is supplied power from one Transformer Station and three 44kV breakers, all owned and operated by Hydro One Networks Inc. LUI distributes electricity to the Town of Cobourg and Village of Colborne at the primary distribution voltage of 27.6kV and 4kV (through six 4kV and two 27.6kV substations).

LUI's licensed service area is 30 square kilometres of urban service area. LUI's distribution system is made up of 68 kilometres of overhead lines, 34 kilometres of underground lines, 3220 poles, 1200 distribution transformers and 9660 meters of which 9500 are Smart Meters installed on Residential and General Service <50 kW customers.

Asset Management Plan

LUI is has developed an Asset Management Plan which outlines the capital and operating expenditures necessary to ensure that LUI continues to provide highest standards for the safe, reliable supply of electricity at the lowest cost. A copy of the Asset Management Plan is attached to this Exhibit as Appendix C. In Appendix D, LUI demonstrates the detail and reporting that has been produced using LUI's Asset Management Tool.

LUI's Asset Management Plan continues to be developed in collaboration with the Town of Cobourg with due regard to the different Acts, Regulations, Codes and Guidelines and the continual updating of good utility practice to ensure the needs of the Town of Cobourg and Village of Colborne customers are met.

RATE BASE VARIANCE ANALYSIS & MATERIALITY

The following below sets out LUI's year over year rate base variances for the 2008 Actual, 2008 OEB Approved, 2009 to 2010 Actuals, 2011 Bridge Year and 2012 Test Year. The Table below identified a range for materiality purposes, from $107,429 to $143,660. For the purposes of this rate application we have made a conscious effort to detail variances that are greater than $50,000 in discussing Rate Base Variances, specifically due to the filing requirements outlining a materiality threshold of $50,000 for distribution revenues less than or equal to $10 million.

Table 2-3 Rate Base Materiality (MIFRS)

Rate Base Materiality

Description	2008 OEB Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Gross Fixed Assets	$20,351,477	$20,383,574	$17,756,449	$18,318,391	$21,515,673	$23,468,673
Accumulated Depreciation	$9,297,933	$9,640,718	$6,903,141	$7,412,314	$8,289,904	$9,102,666
Net Book Value	$11,053,544	$10,742,856	$10,853,308	$10,906,077	$13,225,770	$14,366,008
Variance calc 1% NBV		$107,429	$108,533	$109,061	$132,258	$143,660

Table 2-4A Rate Base Variances (MIFRS)

Rate Base Variances

Rate Base:

Description	2008 OEB Approved	2008 Actual	Variance from 2008 OEB Approved	2009 Actual	2009 Variance from 2008 Actual	2010 Actual	2010 Variance from 2009 Actual	2011 Bridge	2011 Variance from 2010 Actual	2012 Test	2012 Variance from 2011 Bridge
Gross Fixed Assets	20,351,477	20,383,574	32,097	17,756,449	(2,627,125)	18,318,391	561,942	21,515,673	3,197,283	23,468,673	1,953,000
Accumulated Depreciation	9,297,933	9,640,718	342,785	6,903,141	(2,737,577)	7,412,314	509,173	8,289,904	877,590	9,102,666	812,762
Net Book Value (Actual not approved)	11,053,544	10,742,856	(310,688)	10,853,308	110,452	10,906,077	52,769	13,225,770	2,319,693	14,366,008	1,140,238
Average Net Book Value(Act not App)	11,053,544	10,742,856	(310,688)	10,798,082	55,226	10,879,692	81,611	12,065,923	1,186,231	13,795,889	1,729,965
Working Capital	22,810,874	21,670,175	(1,140,699)	21,492,619	(177,557)	22,910,816	1,418,197	24,373,635	1,462,820	25,151,057	777,421
Working Capital Allowance (15%)	3,421,631	3,250,526	(171,105)	3,223,893	(26,634)	3,436,622	212,730	3,656,045	219,423	3,772,659	116,613
Rate Base	14,475,175	13,993,382	(481,793)	14,021,975	28,592	14,316,315	294,340	15,721,969	1,405,654	17,568,547	1,846,579

Table 2-4B Rate Base Variances (CGAAP)

Description	2008 OEB Approved	2008 Actual	Variance from 2008 OEB Approved	2009 Actual	Variance from 2008 Actual	2010 Actual	Variance from 2009 Actual	2011 Bridge	Variance from 2010 Actual	2012 Test	Variance from 2011 Bridge
Gross Fixed Assets	20,351,477	20,383,574	32,097	17,756,449	(2,627,125)	18,318,391	561,942	21,245,673	2,927,283	23,344,673	2,099,000
Accumulated Depreciation	9,297,933	9,640,718	18,938,651	6,903,141	(2,737,577)	7,412,314	509,173	8,287,170	874,857	9,541,584	1,254,414
Net Book Value (Actual not approved)	11,053,544	10,742,856	(310,688)	10,853,308	110,452	10,906,077	52,769	12,958,503	2,052,426	13,803,089	844,586
Average Net Book Value(Act not App)	11,006,545	10,539,841	(466,704)	10,798,082	258,241	10,879,692	81,611	11,932,290	1,052,598	13,380,796	1,448,506
Working Capital	22,710,874	21,670,175	(1,040,699)	21,492,619	(177,557)	22,910,816	1,418,197	25,305,878	2,395,063	26,173,466	867,587
Working Capital Allowance	3,406,631	3,250,526	(156,105)	3,223,893	(26,634)	3,436,622	212,730	3,795,882	359,259	3,926,020	130,138
Rate Base	14,413,176	13,790,367	(622,809)	14,021,975	231,608	14,316,315	294,340	15,728,172	1,411,857	17,306,816	1,578,644

The 2008 Approved Rate Base was higher than 2008 Actual Rate Base mainly due to lower than anticipated working capital spending of over $1,000,000. LUI also began to remove fully depreciated assets from their books. LUI began with gross capital of $ 21,019,622 by the end of the year in 2008, which was reduced by fully depreciated assets of $ 636,048 to be $ 20,383,574 as per Table 2-4 above. The other significant item that caused a lower than planned Rate Base, is due to lower working capital costs. This includes the cost of power, which was budgeted at $ 20,560,245, however cost of power ended up at $ 19,742,668, a difference of $ (817,577).

The 2009 Actual Rate Base variance from 2008 Actual Rate Base is below the materiality threshold, and therefore requires no explanation.

The 2010 Actual Rate Base is greater than 2009 Rate Base by a variance of $ 294,340. LUI had a net increase in capital spending in 2010. The total gross assets this year pre-removal of fully depreciated assets was $ 19,248,489 and fully depreciated assets removed from our books was $ 3,631,020 in 2009 which affects 2010, and removed $ 384,900 in 2010. This shows an increase in capital spending, to reflect that LUI has an aging infrastructure and has been replacing existing 4.16 kV (4kV) to 27.6kV lines. LUI has also had an increase in working capital spending, which causes the Rate Base to increase by $ 212,730.

The 2011 Forecast/Bridget Year Rate Base has increased from 2010 by $ 1,411,857. This figure is a reflection of a few items. First, LUI has had no fully depreciated assets to remove from the capital assets schedule in 2011, and therefore the net increase in capital spending in 2011 is $ **1,988,901**, not including any WIP. This has a positive impact on our average net fixed assets balance. The largest contributor to this increase relates to LUI's requirement for an expansion to its office space, by expanding the Operations Work Centre

(OWC). More discussion surrounding the OWC is outlined later in this Exhibit. LUI has also added Smart Meters to the Rate Base in 2011, and this factor contributes to the increase in Rate Base. Note, this is offset by the removal of stranded assets from Rate Base, and requesting recovery of these balances, through a rider, as outlined in Exhibit 9. LUI has also had some increases in the working capital spending which increased our Rate Base by $ 359,259.

The 2012 Test Year Rate Base has increased from 2011 Bridge Year by $1,797,747. Again this is a result of increased capital spending as well as increased working capital spending, related to succession planning, and other drivers, as discussed in Exhibit 4.

Gross Fixed Asset Variance Analysis

For the purposes of this Application LUI has provided capital investment information for the period 2008 and forward. LUI's investment in capital has increased in each year from 2008 to 2010 as set out in Table 2-7; Percentage Change in Gross Fixed Assets. LUI's capital additions by USoA for the years 2008 to the 2012 Test Year, is provided in Table 2-8 and discussed in further detail in this Exhibit. LUI notes that for analysis purposes that the year over year analysis will be done based on MIFRS in 2012.

CONVERSION TO MODIFIED INTERNATIONAL FINANCIAL REPORTINGSTANDARDS (MIFRS)

The conversion from Canadian Generally Accepted Accounting Principles (CGAAP) to Modified International Financial Reporting Standards (MIFRS) has resulted in some changes to LUI's accounting for Plant Property and Equipment (PP&E).

IMPACT ON FIXED ASSETS

LUI 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 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 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. LUI has reviewed the useful life 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. LUI has restated its continuity statements for the 2012 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. LUI will continue to use the Cost Model to measure PP&E.

Table 2-5 Percentage Change in Gross Fixed Assets (MIFRS)

Gross Assets

REV REQUIREMENT I/S COLUMN

Description	2008 Board Approved	2008 Actual	Percentage % 2008 actual &Board approved	2009 Actual	% change from 2008 and 2009	2010 Actual	% change from 2009 and 2010	2011 Bridge	% change from 2010 and 2011	2012 Test	% change from 2011 and 2012
Intangible Assets											
1610-Intangible Assets	482,400	659,200	37%	600,064	-9%	54,866	-91%	0	-100%	0	
Sub-Total-Land and Buildings	**482,400**	**659,200**	37%	**600,064**	-9%	**54,866**	-91%	**0**	-100%	**0**	
Land and Buildings											
1805-Land	219,284	219,284	0%	219,284	0%	219,284	0%	219,284	0%	219,284	0%
1806-Land Rights	11,363	11,363	0%	0	-100%	0		0		0	
1808-Buildings and Fixtures	825,069	787,877	-5%	862,119	9%	919,216	7%	994,216	8%	1,369,216	38%
Sub-Total-Land and Buildings	**1,055,716**	**1,018,523**	-4%	**1,081,402**	6%	**1,138,499**	5%	**1,213,499**	7%	**1,588,499**	31%
DS											
1820-Distribution Station Equipment - Normally Primary below 50 kV	2,730,090	2,751,440	1%	2,774,813	1%	2,762,235	0%	2,762,235	0%	2,762,235	0%
Sub-Total-DS	**2,730,090**	**2,751,440**	1%	**2,774,813**	1%	**2,762,235**	0%	**2,762,235**	0%	**2,762,235**	0%
Poles and Wires											
1830-Poles, Towers and Fixtures	4,257,766	4,161,770	-2%	805,335	-81%	1,107,311	37%	1,557,311	41%	1,797,311	15%
1835-Overhead Conductors and Devices	3,131,109	3,332,377	6%	3,565,181	7%	3,813,754	7%	4,213,754	10%	4,422,754	5%
1840-Underground Conduit	446,063	446,063	0%	499,541	12%	878,943	76%	1,228,943	40%	1,388,943	13%
1845-Underground Conductors and Devices	2,807,068	2,815,942	0%	2,872,314	2%	3,066,154	7%	3,066,154	0%	3,066,154	0%
Sub-Total-Poles and Wires	**10,642,006**	**10,756,151**	1%	**7,742,370**	-28%	**8,866,162**	15%	**10,066,162**	14%	**10,675,162**	6%
Line Transformers											
1850-Line Transformers	4,195,996	4,391,844	5%	4,780,641	9%	5,111,049	7%	5,351,049	5%	5,543,049	4%
Sub-Total-Line Transformers	**4,195,996**	**4,391,844**	5%	**4,780,641**	9%	**5,111,049**	7%	**5,351,049**	5%	**5,543,049**	4%
Services and Meters											
1855-Services	377,581	419,152	11%	453,103	8%	509,529	12%	599,529	18%	623,529	4%
1860-Meters	905,640	874,954	-3%	890,316	2%	894,462	0%	2,047,905	129%	2,097,905	2%
1861-Smart Meters											
Sub-Total-Services and Meters	**1,283,221**	**1,294,106**	1%	**1,343,419**	4%	**1,403,992**	5%	**2,647,434**	89%	**2,721,434**	3%
IT Assets											
1920-Computer Equipment - Hardware	60,595	113,886	88%	117,818	3%	31,199	-74%	81,199	160%	231,199	185%
1925-Computer Software	160,926	100,071	-38%	66,132	-34%	113,876	72%	287,582	153%	612,582	113%
Sub-Total-IT Assets	**221,521**	**213,956**	-3%	**183,949**	-14%	**145,075**	-21%	**368,781**	154%	**843,781**	129%
Equipment											
1915-Office Furniture and Equipment	108,191	83,915	-22%	107,816	28%	57,026	-47%	82,026	44%	107,026	30%
1930-Transportation Equipment	510,134	630,840	24%	585,222	-7%	759,705	30%	759,705	0%	814,705	7%
1940-Tools, Shop and Garage Equipment	93,083	84,981	-9%	158,730	87%	158,730	0%	233,730	47%	627,730	169%
1945-Measurement and Testing Equipment	(2,785)	0	-100%	0		18,712		18,712	0%	18,712	0%
Sub-Total-Equipment	**708,623**	**799,736**	13%	**851,768**	7%	**994,172**	17%	**1,094,172**	10%	**1,568,172**	43%
Other Distribution Assets											
1995-Contributions and Grants - Credit	(968,096)	(1,501,383)	55%	(1,601,978)	7%	(2,157,659)	35%	(2,257,659)	5%	(2,357,659)	4%
Sub-Total-Other Distribution Assets	**(968,096)**	**(1,501,383)**	55%	**(1,601,978)**	7%	**(2,157,659)**	35%	**(2,257,659)**	5%	**(2,357,659)**	4%
GROSS ASSET TOTAL	**20,351,477**	**20,383,574**	-1%	**17,756,449**	-13%	**18,318,391**	6%	**21,245,673**	16%	**23,344,673**	10%

Table 2-6 Gross Asset Variances by Year (MIFRS)

Gross Assets

REV REQUIREMENT I/S COLUMN		D		F		H		J		L	
Description	2008 Board Approved	2008 Actual	Variance from 2008 Board Approved	2009 Actual	Variance from 2008 Actual	2010 Actual	Variance from 2009 Actual	2011 Bridge	Variance from 2010 Actual	2012 Test	Variance from 2011 Bridge
Intangible Assets											
1610-Intangible Assets	482,400	659,200	176,800	600,064	(59,136)	54,866	(545,198)		(54,866)		
Sub-Total-Land and Buildings	**482,400**	**659,200**	**176,800**	**600,064**	**(59,136)**	**54,866**	**(545,198)**		**(54,866)**		
Land and Buildings											
1805-Land	219,284	219,284	(0)	219,284		219,284		219,284		219,284	
1806-Land Rights	11,363	11,363			(11,363)						
1808-Buildings and Fixtures	825,069	787,877	(37,192)	862,119	74,242	919,216	57,097	994,216	75,000	1,369,216	375,000
Sub-Total-Land and Buildings	**1,055,716**	**1,018,523**	**(37,193)**	**1,081,402**	**62,879**	**1,138,499**	**57,097**	**1,213,499**	**75,000**	**1,588,499**	**375,000**
DS											
1820-Distribution Station Equipment - Normally Primary below 50 kV	2,730,090	2,751,440	21,350	2,774,813	23,373	2,762,235	(12,578)	2,762,235		2,762,235	
Sub-Total-DS	**2,730,090**	**2,751,440**	**21,350**	**2,774,813**	**23,373**	**2,762,235**	**(12,578)**	**2,762,235**		**2,762,235**	
Poles and Wires											
1830-Poles, Towers and Fixtures	4,257,766	4,161,770	(95,996)	805,335	(3,356,435)	1,107,311	301,976	1,557,311	450,000	1,797,311	240,000
1835-Overhead Conductors and Devices	3,131,109	3,332,377	201,268	3,565,181	232,804	3,813,754	248,573	4,213,754	400,000	4,422,754	209,000
1840-Underground Conduit	446,063	446,063	(0)	499,541	53,478	878,943	379,402	1,228,943	350,000	1,388,943	160,000
1845-Underground Conductors and Devices	2,807,068	2,815,942	8,874	2,872,314	56,372	3,066,154	193,840	3,066,154		3,066,154	
Sub-Total-Poles and Wires	**10,642,006**	**10,756,151**	**114,145**	**7,742,370**	**(3,013,781)**	**8,866,162**	**1,123,792**	**10,066,162**	**1,200,000**	**10,675,162**	**609,000**
Line Transformers											
1850-Line Transformers	4,195,996	4,391,844	195,848	4,780,641	388,797	5,111,049	330,408	5,351,049	240,000	5,543,049	192,000
Sub-Total-Line Transformers	**4,195,996**	**4,391,844**	**195,848**	**4,780,641**	**388,797**	**5,111,049**	**330,408**	**5,351,049**	**240,000**	**5,543,049**	**192,000**
Services and Meters											
1855-Services	377,581	419,152	41,571	453,103	33,951	509,529	56,426	599,529	90,000	623,529	24,000
1860-Meters	905,640	874,954	(30,686)	890,316	15,362	894,462	4,147	225,726	(668,736)	275,726	50,000
1860-Smart Meters								1,822,179		1,822,179	
Sub-Total-Services and Meters	**1,283,221**	**1,294,106**	**10,885**	**1,343,419**	**49,313**	**1,403,992**	**60,573**	**2,647,434**	**(578,736)**	**2,721,434**	**74,000**
IT Assets											
1920-Computer Equipment - Hardware	60,595	113,886	53,291	117,818	3,932	31,199	(86,618)	81,199	50,000	231,199	150,000
1925-Smart Meters Software								123,706	123,706	123,706	
1925-Computer Software	160,926	100,071	(60,855)	66,132	(33,939)	113,876	47,744	163,876	50,000	488,876	325,000
Sub-Total-IT Assets	**221,521**	**213,956**	**(7,565)**	**183,949**	**(30,007)**	**145,075**	**(38,875)**	**368,781**	**223,706**	**843,781**	**475,000**
Equipment											
1915-Office Furniture and Equipment	108,191	83,915	(24,276)	107,816	23,901	57,026	(50,791)	82,026	25,000	107,026	25,000
1930-Transportation Equipment	510,134	630,840	120,706	585,222	(45,618)	759,705	174,483	759,705		814,705	55,000
1940-Tools, Shop and Garage Equipment	93,083	84,981	(8,102)	158,730	73,749	158,730		233,730	75,000	627,730	394,000
1945-Measurement and Testing Equipment	(2,785)		2,785			18,712	18,712	18,712		18,712	
Sub-Total-Equipment	**708,623**	**799,736**	**91,113**	**851,768**	**52,032**	**994,172**	**142,404**	**1,094,172**	**100,000**	**1,568,172**	**474,000**
Other Distribution Assets											
1995-Contributions and Grants - Credit	(968,096)	(1,501,383)	(533,287)	(1,601,978)	(100,595)	(2,157,659)	(555,681)	(2,257,659)	(100,000)	(2,357,659)	(100,000)
Sub-Total-Other Distribution Assets	**(968,096)**	**(1,501,383)**	**(533,287)**	**(1,601,978)**	**(100,595)**	**(2,157,659)**	**(555,681)**	**(2,257,659)**	**(100,000)**	**(2,357,659)**	**(100,000)**
GROSS ASSET TOTAL	**20,351,477**	**20,383,574**	**32,097**	**17,756,449**	**(2,627,125)**	**18,318,391**	**561,942**	**21,245,673**	**1,105,104**	**23,344,673**	**2,099,000**

LUI has prepared and presented the year over year analysis for each year in a consistent format for comparison purposes.

2008 Board Approved vs. 2008 Board Actual

The 2008 Actual versus 2008 Board Approved gross assets are not signifcantly different year over year. Therefore no dsicussion is required.

2009 Actual vs. 2008 Actual

There is a significant decrease in the gross assets from 2009 to 2008. The variance totals $ (2,627,125). LUI removed a total of $ 3,631,020 of fully depreciated assets from their books and therefore accounts for the decrease in this account. The offset to these fully depreciated assets, was the increased spending on overhead and transformers.

2010 Actual vs. 2009 Actual

In 2010, LUI had a net increase in gross assets of $561,942. This balances consists mainly of approximately $ 1,492,040 in additional capital spending, offset by a small reduction to gross assets of $ 384,900 of fully depreciated assets in 2010.

2011 Bridge Year vs. 2010 Actual

In the 2011 Bridge Year we see an increase in gross assets of $ 1,105,104 over the 2010 Actual Year. This is mainly attributable to the necessary expansion to the OWC in order to manage space and inventory issues. This project is expected to cost approximately $375,000 over the next two years, not including required interior updates, plumbing, workstations, etc. This will be discussed further in this Exhibit.

2012 Test Year vs. 2011 Bridge Year

The 2012 Test Year is $2,099,000 higher than the 2011 year. LUI has three key drivers of its capital investment. The first driver of LUI's capital investment is its obligation to connect

a customer in accordance with Section 28 of the *Electricity Act, 1998*, Section 7 of LUI's Electricity Distribution License and the Distribution System Code. As previously discussed, the Town of Cobourg and therefore LUI have experienced growth since 2001. In many development areas LUI did not have existing distribution plant capable of supplying the new developments and as such, LUI is required to construct the expansion of its overhead distribution plant. LUI contributes to the subdivision based on an economic evaluation in accordance with the DSC. The developer is allowed to build the subdivision based on LUI's subdivision agreement outlining specifications and LUI contributes based on actual connections and load over a 5 year horizon.

The second driver is also a result of the growth in the Town of Cobourg whereby the Town is investing in the widening of roads, installation of sewers and water which in many cases results in LUI being required to relocate existing distribution lines. LUI collects a partial recovery of these costs in accordance with the Municipal Act.

The third driver is LUI's own capital investment required to meet its commitment to provide a safe and reliable supply of electricity to its customers. Details are provided in LUI's Asset Management Plan attached as Appendix C to this Exhibit but in summary includes the rebuilding and conversion of deteriorating 4kV distribution plant, pole replacement and other capital works required as a result of inspection and testing of existing distribution plant. Other Asset investments include building/facilities, computer hardware, software, vehicles and communication equipment.

Accumulated Amortization Variance Analysis

Table 2-7 Accumulated Amortization (MIFRS)

Accumulated Depreciation

Description	2008 Board Approved	2008 Actual	Variance from 2008 Board Approved	2009 Actual	Variance from 2008 Actual	2010 Actual	Variance from 2009 Actual	2011 Bridge	Variance from 2010 Actual	2012 Test	Variance from 2011 Bridge
Intangible Assets											
1610-Intangible Assets											
Sub-Total-Land and Buildings											
Land and Buildings											
1805-Land											
1806-Land Rights	910		(910)								
1808-Buildings and Fixtures	77,583	80,340	2,757	98,905	18,565	118,783	19,878	139,982	21,199	170,834	30,853
1905-Land											
1906-Land Rights											
1810-Leasehold Improvements											
Sub-Total-Land and Buildings	**78,493**	**80,340**	**1,847**	**98,905**	**18,565**	**118,783**	**19,878**	**139,982**	**21,199**	**170,834**	**30,853**
TS Primary Above 50											
1815-Transformer Station Equipment - Normally Primary above 50 kV											
Sub-Total-TS Primary Above 50											
DS											
1820-Distribution Station Equipment - Normally Primary below 50 kV	1,459,025	1,454,646	(4,379)	1,543,908	89,262	1,598,842	54,934	1,720,437	121,595	1,770,531	50,094
Sub-Total-DS	**1,459,025**	**1,454,646**	**(4,379)**	**1,543,908**	**89,262**	**1,598,842**	**54,934**	**1,720,437**	**121,595**	**1,770,531**	**50,094**
Poles and Wires											
1830-Poles, Towers and Fixtures	3,840,294	3,541,337	(298,957)	126,195	(3,415,142)	164,448	38,253	217,741	53,293	271,801	54,060
1835-Overhead Conductors and Devices	(202,456)	212,728	415,184	490,657	277,929	761,802	271,145	1,036,323	274,521	1,129,324	93,002
1840-Underground Conduit	124,450	125,991	1,541	145,674	19,683	174,014	28,340	216,943	42,928	254,921	37,978
1845-Underground Conductors and Devices	1,591,385	1,589,757	(1,628)	1,702,354	112,597	1,819,955	117,601	1,941,432	121,478	2,017,028	75,595
Sub-Total-Poles and Wires	**5,353,673**	**5,469,813**	**116,140**	**2,464,880**	**(3,004,933)**	**2,920,219**	**455,339**	**3,412,439**	**492,220**	**3,673,074**	**260,635**
Line Transformers											
1850-Line Transformers	1,826,615	1,829,447	2,832	2,011,895	182,448	2,204,716	192,821	2,408,631	203,914	2,566,961	158,330
Sub-Total-Line Transformers	**1,826,615**	**1,829,447**	**2,832**	**2,011,895**	**182,448**	**2,204,716**	**192,821**	**2,408,631**	**203,914**	**2,566,961**	**158,330**
Services and Meters											
1855-Services	106,210	106,766	556	123,725	16,959	142,492	18,767	164,187	21,695	174,351	10,163
1860-Meters	463,386	460,813	(2,573)	495,851	35,038	531,280	35,429	157,638	(373,642)	166,656	9,018
1860-Smart Meters								243,758	243,758	356,502	112,744
Sub-Total-Services and Meters	**569,596**	**567,579**	**(2,017)**	**619,576**	**51,997**	**673,772**	**54,196**	**565,583**	**(108,189)**	**697,509**	**131,926**
General Plant											
1908-Buildings and Fixtures	(24,529)		24,529								
1910-Leasehold Improvements											
Sub-Total-General Plant	**(24,529)**		**24,529**								
IT Assets											
1920-Computer Equipment - Hardware	21,862	85,777	63,915	100,224	14,447	12,705	(87,519)	23,945	11,240	53,496	29,551
1925 Computer Software Smart Meters								52,475	52,475	68,304	15,829
1925-Computer Software	57,706	49,046	(8,660)	28,333	(20,713)	46,334	18,001	73,712	27,378	131,474	57,762
Sub-Total-IT Assets	**79,568**	**134,823**	**55,255**	**128,557**	**(6,266)**	**59,039**	**(69,518)**	**150,132**	**91,093**	**253,275**	**103,143**
Equipment											
1915-Office Furniture and Equipment	46,115	60,155	14,040	57,928	(2,227)	7,334	(50,594)	14,286	6,953	23,739	9,453
1930-Transportation Equipment	91,724	246,223	154,499	229,806	(16,417)	149,873	(79,933)	244,837	94,963	345,300	100,463
1935-Stores Equipment											
1940-Tools, Shop and Garage Equipment	35,764	39,573	3,809	48,849	9,276	48,849		67,780	18,931	116,914	49,134
1945-Measurement and Testing Equipment	(3,343)	(2,785)	558		2,785	936	936	2,807	1,871	4,678	1,871
1950-Power Operated Equipment											
1955-Communication Equipment											
1960-Miscellaneous Equipment											
Sub-Total-Equipment	**170,260**	**343,166**	**172,906**	**336,583**	**(6,583)**	**206,992**	**(129,591)**	**329,710**	**122,718**	**490,631**	**160,921**
Other Distribution Assets											
1825-Storage Battery Equipment											
1970-Load Management Controls - Customer Premises											
1975-Load Management Controls - Utility Premises											
1980-System Supervisory Equipment	(2,031)		2,031								
1985-Sentinel Lighting Rental Units											
1990-Other Tangible Property											
1995-Contributions and Grants - Credit	(212,737)	(239,096)	(26,359)	(301,163)	(62,067)	(370,049)	(68,886)	(439,742)	(69,693)	(519,435)	(79,693)
1996-Hydro One S/S Contribution											
Sub-Total-Other Distribution Assets	**(214,768)**	**(239,096)**	**(24,328)**	**(301,163)**	**(62,067)**	**(370,049)**	**(68,886)**	**(439,742)**	**(69,693)**	**(519,435)**	**(79,693)**
ACCUMULATED DEPRICIATION TOTAL	**9,297,933**	**9,640,718**	**342,785**	**6,903,141**	**(2,737,577)**	**7,412,314**	**509,173**	**8,287,170**	**874,857**	**9,103,379**	**816,209**

Table 2-8 Accumulated Amortization % Change

Accumulated Depreciation

Description	2008 Board Approved	2008 Actual	Percentage % 2008 actual &Board approved	2009 Actual	% change from 2008 and 2009	2010 Actual	% change from 2009 and 2010	2011 Bridge	% change from 2010 and 2011	2012 Test	% change from 2011 and 2012
Intangible Assets											
1610-Intangible Assets	0	0		0		0		0		0	
Sub-Total-Land and Buildings	**0**	**0**		**0**		**0**		**0**		**0**	
Land and Buildings											
1805-Land		0		0		0		0		0	
1806-Land Rights	910	0	-100.00%	0		0		0		0	
1808-Buildings and Fixtures	77,583	80,340	3.55%	98,905	23.11%	118,783	20.10%	139,982	17.85%	170,834	22.04%
1905-Land		0		0		0		0		0	
1906-Land Rights		0		0		0		0		0	
1810-Leasehold Improvements		0		0		0		0		0	
Sub-Total-Land and Buildings	**78,493**	**80,340**	2.35%	**98,905**	23.11%	**118,783**	20.10%	**139,982**	17.85%	**170,834**	22.04%
TS Primary Above 50											
1815-Transformer Station Equipment - Normally Primary above 50 kV	0	0		0		0		0		0	
Sub-Total-TS Primary Above 50	**0**	**0**		**0**		**0**		**0**		**0**	
DS											
1820-Distribution Station Equipment - Normally Primary below 50 kV	1,459,025	1,454,646	-0.30%	1,543,908	6.14%	1,598,842	3.56%	1,720,437	7.61%	1,770,531	2.91%
Sub-Total-DS	**1,459,025**	**1,454,646**	-0.30%	**1,543,908**	6.14%	**1,598,842**	3.56%	**1,720,437**	7.61%	**1,770,531**	2.91%
Poles and Wires											
1830-Poles, Towers and Fixtures	3,840,294	3,541,337	-7.78%	126,195	-96.44%	164,448	30.31%	217,741	32.41%	271,801	24.83%
1835-Overhead Conductors and Devices	(202,456)	212,728	-205.07%	490,657	130.65%	761,802	55.26%	1,036,323	36.04%	1,129,324	8.97%
1840-Underground Conduit	124,450	125,991	1.24%	145,674	15.62%	174,014	19.45%	216,943	24.67%	254,921	17.51%
1845-Underground Conductors and Devices	1,591,385	1,589,757	-0.10%	1,702,354	7.08%	1,819,955	6.91%	1,941,432	6.67%	2,017,028	3.89%
Sub-Total-Poles and Wires	**5,353,673**	**5,469,813**	2.17%	**2,464,880**	-54.94%	**2,920,219**	18.47%	**3,412,439**	16.86%	**3,673,074**	7.64%
Line Transformers											
1850-Line Transformers	1,826,615	1,829,447	0.16%	2,011,895	9.97%	2,204,716	9.58%	2,408,631	9.25%	2,566,961	6.57%
Sub-Total-Line Transformers	**1,826,615**	**1,829,447**	0.16%	**2,011,895**	9.97%	**2,204,716**	9.58%	**2,408,631**	9.25%	**2,566,961**	6.57%
Services and Meters											
1855-Services	106,210	106,766	0.52%	123,725	15.88%	142,492	15.17%	164,187	15.23%	174,351	6.19%
1860-Meters	463,386	460,813	-0.56%	495,851	7.60%	531,280	7.15%	157,638	-70.33%	166,656	5.72%
1861-Smart Meters											
Sub-Total-Services and Meters	**569,596**	**567,579**	-0.35%	**619,576**	9.16%	**673,772**	8.75%	**321,825**	-52.24%	**341,007**	5.96%
General Plant											
1908-Buildings and Fixtures	(24,529)	0	-100.00%	0	0.00%	0		0		0	
1910-Leasehold Improvements	0	0		0		0		0		0	
Sub-Total-General Plant	**(24,529)**	**0**	-100.00%	**0**	0.00%	**0**		**0**		**0**	
IT Assets											
1920-Computer Equipment - Hardware	21,862	85,777	292.36%	100,224	16.84%	12,705	-87.32%	14,286	12.45%	23,739	66.17%
1921-Computer Equipment - Hardware post March 22, 2004											
1925-Computer Software	57,706	49,046	-15.01%	28,333	-42.23%	46,334	63.53%	23,945	-48.32%	53,496	123.41%
Sub-Total-IT Assets	**79,568**	**134,823**	69.44%	**128,557**	-4.65%	**59,039**	-54.08%	**38,231**	-35.24%	**77,235**	102.02%
Equipment											
1915-Office Furniture and Equipment	46,115	60,155	30.45%	57,928	-3.70%	7,334	-87.34%	0	-100.00%	0	
1930-Transportation Equipment	91,724	246,223	168.44%	229,806	-6.67%	149,873	-34.78%	73,712	-50.82%	131,474	78.36%
1935-Stores Equipment		0		0		0		52,475		68,304	30.16%
1940-Tools, Shop and Garage Equipment	35,764	39,573	10.65%	48,849	23.44%	48,849		244,837	401.21%	345,300	41.03%
1945-Measurement and Testing Equipment	(3,343)	(2,785)	-16.69%	0	-100.00%	936	#DIV/0!	0	-100.00%	0	
1950-Power Operated Equipment		0		0		0		67,780		116,914	72.49%
1955-Communication Equipment		0		0		0		2,807		4,678	66.67%
1960-Miscellaneous Equipment		0		0		0		0		0	
Sub-Total-Equipment	**170,260**	**343,166**	101.55%	**336,583**	-1.92%	**206,992**	-38.50%	**441,610**	113.35%	**666,670**	50.96%
Other Distribution Assets											
1825-Storage Battery 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	(2,031)	0	-100.00%	0	0.00%	0		0		0	
1985-Sentinel Lighting Rental Units		0		0		0		0		0	
1990-Other Tangible Property		0		0		0		0		0	
1995-Contributions and Grants - Credit	(212,737)	(239,096)	12.39%	(301,163)	25.96%	(370,049)	22.87%	(439,742)	18.83%	(519,435)	18.12%
1996-Hydro One S/S Contribution											
Sub-Total-Other Distribution Assets	**(214,768)**	**(239,096)**	11.33%	**(301,163)**	25.96%	**(370,049)**	22.87%	**(439,742)**	18.83%	**(519,435)**	18.12%
ACCUMULATED DEPRICIATION TOTAL	**9,297,933**	**9,640,718**	3.69%	**6,903,141**	-28.40%	**7,412,314**	7.38%	**8,043,413**	8.51%	**8,746,877**	8.75%

The variance year over year accumulated amortization is directly attributable to capital spending and the removal of fully depreciated assets from the records. Any discussions surrounding these items has been addressed in full , above in the section on Gross Assets.

Table 2-9 Capital Additions 2008 Actual to 2012 Test Year

OEB	Description	Additions 2008	2009	2010	2011	2012
1610	Intangible Assets	76,800.00	47,200.00		(54,866.00)	-
1805	Land			-	-	-
1806	Land Rights		-		-	-
1808	Buildings and Fixtures	22,807.58	74,242.00	57,097.03	75,000.00	375,000.00
1810	Leasehold Improvements		-		-	-
1815	Transformer Station Equipment - Normally Primary above 50 kV		-		-	-
1820	Distribution Station Equipment - Normally Primary below 50 kV	6,000.00	23,373.00	22,514.47	-	-
1825	Storage Battery Equipment		-		-	-
1830	Poles, Towers and Fixtures	173,875.40	104,867.00	301,976.45	450,000.00	240,000.00
1835	Overhead Conductors and Devices	294,659.52	232,804.00	248,573.16	400,000.00	209,000.00
1840	Underground Conduit		53,478.00	379,402.26	350,000.00	160,000.00
1845	Underground Conductors and Devices		56,372.00	193,839.73	-	-
1850	Line Transformers	573,895.24	388,797.00	330,408.14	240,000.00	192,000.00
1855	Services	10,955.12	33,951.00	56,425.66	90,000.00	24,000.00
1860	Meters	19,737.24	15,362.00	4,146.86	(668,736.23)	50,000.00
1860	Smart Meters				255,355.00	-
1865	Other Installations on Customer's Premises		-		-	-
1905	Land		-		-	-
1906	Land Rights		-		-	-
1908	Buildings and Fixtures		-		-	-
1910	Leasehold Improvements		-		-	-
1915	Office Furniture and Equipment	1,750.36	41,318.00	13,956.94	25,000.00	25,000.00
1920	Computer Equipment - Hardware	3,924.37	10,525.00	8,307.51	50,000.00	150,000.00
1925	Computer Software	39,144.87		47,743.93	50,000.00	325,000.00
1925	Computer Softward - Smart Meters				8,546.00	-
1930	Transportation Equipment	284,466.60	54,788.00	364,617.00	-	55,000.00
1935	Stores Equipment				-	-
1940	Tools, Shop and Garage Equipment	8,386.67	73,749.00		75,000.00	394,000.00
1945	Measurement and Testing Equipment		-	18,711.50	-	-
1950	Power Operated Equipment		-		-	-
1955	Communication Equipment		-		-	-
1960	Miscellaneous Equipment		-		-	-
1970	Load Management Controls - Customer Premises		-		-	-
1975	Load Management Controls - Utility Premises		-		-	-
1980	System Supervisory Equipment		-		-	-
1985	Sentinel Lighting Rentals		-		-	-
1990	Other Tangible Property		-		-	-
1995	Contributions and Grants	(271,735.00)	(100,595.00)	(555,680.95)	(100,000.00)	(100,000.00)
2005	Property under Capital Lease				-	-
	Total before Work in Process	**1,244,667.97**	**1,110,231.00**	**1,492,039.69**	**1,245,298.77**	**2,099,000.00**
					-	
	Work in Process					
	Total after Work in Process	**1,244,667.97**	**1,110,231.00**	**1,492,039.69**	**1,245,298.77**	**2,099,000.00**

Capital Projects Exceeding Materiality Threshold

The following section sets out the year over year variances in LUI's capital expenditures by the OEB's USoA classification. Also provided are the annual fixed asset continuity schedules, capital projects by USoA and explanations for the capital projects exceeding the materiality threshold of $50,000. This information has been presented for the years 2008 to 2010 Actuals, the 2011 Bridge Year and the 2012 Test Year.

Table 2-9 below sets out the year over year gross asset variances by the OEB's USoA classification. LUI has prepared the year over year analysis in a consistent format for comparison purposes

2008 Actual Capital Additions

The 2008 Fixed Asset Continuity Schedule, in the Table below provides a summary of the additions and disposals based on the OEB USoA classification. This schedule may also be found in LUI's Revenue Requirement Model attached to this Application.

Table 2-10 2008 Fixed Asset Continuity Schedule

CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1610	Intangible Assets	582,400	76,800		659,200	0			0	659,200
N/A	1805	Land	219,284			219,284	0			0	219,284
CEC	1806	Land Rights	11,363			11,363	0			0	11,363
1	1808	Buildings and Fixtures	765,069	22,808		787,877	62,746	17,594		80,340	707,537
	1810	Leasehold Improvements	0			0	0			0	0
	1815	Transformer Station Equipment - Normally Prima	0			0	0			0	0
1	1820	Distribution Station Equipment - Normally Primar	2,745,440	6,000		2,751,440	1,365,873	88,773		1,454,646	1,296,794
	1825	Storage Battery Equipment	0			0	0			0	0
1	1830	Poles, Towers and Fixtures	3,987,894	173,875		4,161,770	3,532,840	24,541	16,044	3,541,337	620,433
1	1835	Overhead Conductors and Devices	3,158,069	294,660	120,352	3,332,377	59,460	273,618	120,350	212,728	3,119,649
1	1840	Underground Conduit	446,063			446,063	107,378	18,613		125,991	320,072
1	1845	Underground Conductors and Devices	2,815,942			2,815,942	1,478,288	111,469		1,589,757	1,226,185
1	1850	Line Transformers	3,817,949	573,895		4,391,844	1,648,644	163,194	(17,609)	1,829,447	2,562,397
1	1855	Services	408,197	10,955		419,152	91,845	16,061	1,140	106,766	312,386
1	1860	Meters	855,216	19,737		874,954	425,293	34,336	(1,184)	460,813	414,141
	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights	0			0	0			0	0
1	1908	Buildings and Fixtures	428,577		428,577	0	428,577		428,577	0	0
	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	83,191	1,750	1,026	83,915	44,660	16,521	1,026	60,155	23,760
45	1920	Computer Equipment - Hardware	161,543	3,924	51,581	113,886	110,790	28,172	53,185	85,777	28,109
12	1925	Computer Software	60,926	39,145		100,071	39,732	9,314		49,046	51,025
10	1930	Transportation Equipment	346,373	284,467		630,840	163,357	82,866		246,223	384,617
10	1935	Stores Equipment	0			0	0			0	0
8	1940	Tools, Shop and Garage Equipment	82,487	8,387	5,892	84,981	36,653	8,182	5,262	39,573	45,408
	1945	Measurement and Testing Equipment	0			0	(2,151)		634	(2,785)	2,785
	1950	Power Operated Equipment	0			0	0			0	0
10	1955	Communication Equipment	0			0	0			0	0
	1960	Miscellaneous Equipment	0			0	0			0	0
	1970	Load Management Controls - Customer Premise	0			0	0			0	0
	1975	Load Management Controls - Utility Premises	0			0	0			0	0
	1980	System Supervisory Equipment	28,619		28,619	0	28,619		28,619	0	0
	1985	Sentinel Lighting Rentals	0			0	0			0	0
	1990	Other Tangible Property	0			0	0			0	0
1	1995	Contributions and Grants	(1,229,648)	(271,735)		(1,501,383)	(184,475)	(54,621)		(239,096)	(1,262,287)
	2005	Property under Capital Lease	0			0				0	0
		Total before Work in Process	**19,774,954**	**1,244,668**	**636,048**	**20,383,574**	**9,438,129**	**838,633**	**636,044**	**9,640,718**	**10,742,856**
WIP		Work in Process	0			0	0			0	0
		Total after Work in Process	**19,774,954**	**1,244,668**	**636,048**	**20,383,574**	**9,438,129**	**838,633**	**636,044**	**9,640,718**	**10,742,856**

2008 Actual Capital Projects (exceeding threshold)

The following Table 2-1 provides LUI's capital additions, exceeding the materiality threshold of $50,000, by project, project type and USoA as well as the total projects, by USoA that fall under the materiality threshold.

LUI 2008 CAPITAL PROJECTS – MATERIALITY > $25,000

Table 2-11 2008 Actual Capital Projects

2008 Actual Capital Projects			1610	1808	1820	1830	1835	1840	1845	1850	1855	1860	1915	1920	1925	1930	1940	1995	
Projects	Type of Projec	Type of Project	Other	Buildings	Distribution Station	Poles, Towers & Fixtures	O/H Cond & Devices	U/G Conduit	U/G Cond & Devices	Line Transformer	Services	Meters	Office Equipm	Computer Hardware	Computer Software	Transportation Equipment	Tools & Equipment	Contributions & Grants	Total
William Street	Rebuild / Upgrade	Rebuild / Upgrade								30,050									30,050
Burnham St - William St	Rebuild / Upgrade	Rebuild / Upgrade				22,301	33,956			10,274									66,531
Carlisle Street	Rebuild / Upgrade	Rebuild / Upgrade				12,311	21,998			8,940									43,249
Curtis Crescent	Rebuild / Upgrade	Rebuild / Upgrade				9,394	28,577			8,855									46,826
Northwood Drive	Rebuild / Upgrade	Rebuild / Upgrade				10,277	27,981			13,599									51,857
Westwood Dr North End	Rebuild / Upgrade	Rebuild / Upgrade					31,529			6,536									38,065
William ROW to Tracks	Rebuild / Upgrade	Rebuild / Upgrade				42,609	65,047			37,680									145,336
Swayne Street	Rebuild / Upgrade	Rebuild / Upgrade				13,028	38,720			50,586									102,335
Westwood Dr	Rebuild / Upgrade	Rebuild / Upgrade								10,697									10,697
Jarvis Rd - Load Transfer	Rebuild / Upgrade	Rebuild / Upgrade				3,786	1,345			2,482									7,613
Division & Park	Rebuild / Upgrade	Rebuild / Upgrade								171									171
Sinclair 28KV	Rebuild / Upgrade	Rebuild / Upgrade					509												509
Westwood Cres	Rebuild / Upgrade	Rebuild / Upgrade								9,619									9,619
Westwood to Northwood	Rebuild / Upgrade	Rebuild / Upgrade								6,449									6,449
Carlisle(Burham - Curtis)	Rebuild / Upgrade	Rebuild / Upgrade								2,491									2,491
John Street South - 28KV Conversion	Rebuild / Upgrade	Rebuild / Upgrade				8,373													8,373
Bagot Street - Rebuild	Rebuild / Upgrade	Rebuild / Upgrade				7,813													7,813
Furnace Street	Rebuild / Upgrade & Betterment	Rebuild / Upgrade				15,265				19,700									34,965
Misc. Underground development	Underground Services	Expansion									7,972								7,972
Misc. Overhead Development	Overhead Services	Expansion									2,983								2,983
Palisade Gardens - 240 Chapel St	New Commercial Customer	Expansion								35,132									35,132
Northumberland Cty - 860 William St	Commercial Customer Upgrade Service	Expansion								20,096									20,096
260 Division St	Commercial Customer Upgrade Service	Expansion								21,190									21,190
DD Mac Electric	Commercial Customer Upgrade Service	Expansion								9,077									9,077
75 White Street	Commercial Customer Upgrade Service	Expansion								24,325									24,325
Northumberland Mall - Elgin St	Commercial Customer Upgrade Service	Expansion								27,645									27,645
68 King St West	Commercial Customer Upgrade Service	Expansion								3,000									3,000
Town of Cobourg - 6 Darcy St	Commercial Customer Upgrade Service	Expansion								46,496									46,496
VanDyk - Westpark Village	Subdivision	Expansion								22,110									22,110
Fraser Ford 1056 Elgin Streeet	New Commercial Development	Expansion								23,042									23,042
Division Street Tim's Gas Bar	New Commercial Development	Expansion								31,987									31,987
73-77 King Street Transformer	New Commercial Development	Expansion								27,043									27,043
LeBlanc - 12 Elgin Street East	Subdivision	Expansion								23,627									23,627
1125 Elgin Street Mark's Work Wearhouse	New Commercial Development	Expansion					28,577			17,641									46,218
Palisade Gardens - 240 Chapel St - O/H Road Crossing	Commercial Customer Upgrade Service	Expansion					8,507												8,507
Havelock St - New pole Line	Municipal Initiative	Municipal Initiative				6,901	7,914			4,768									19,583
Road Construction -TOC Havelock/James St	Municipal Initiative	Municipal Initiative				6,639													6,639
Distribution Station equipment	LUI	Upgrade			6,000														6,000
Transportation Equipment	LUI	Transportation Equipment														284,467			284,467
Tools	LUI	Tools															8,387		8,387
Computer Software	LUI	Software													39,145				39,145
Storage - Shelving	LUI	Office Equipment											1,750						1,750
Meters	LUI	Meters										19,737							19,737
Computer Hardware	LUI	Hardware												3,924					3,924
New Office Furnace Unit	LUI	Building Upgrades		7,981															7,981
Pole Yard Upgrade & Fence	LUI	Building Upgrades		13,017															13,017
Ewart St Garage Signage	LUI	Building Upgrades		1,809															1,809
Capital Contributions	LUI																	-271,735	-271,735
Miscellaneous Other Projects	Rebuild / Upgrade	Rebuild / Upgrade	76,800			15,179				18,589									110,568
ACCOUNT TOTALS			0	22,808	6,000	158,696	294,659	0	0	555,307	10,955	19,737	1,750	3,924	39,145	284,467	8,387	-271,735	**114,483**

2008 OVERHEAD REBUILD/UPGRADE CONVERSION PROJECTS

REBUILD/UPGRADE NEED:

LUI has a population of approximately 3,200 overhead line poles. LUI recognizes that the conditions of these assets deteriorate over time and LUI takes a proactive approach to their replacement. Asset Management Programs are put in place to inspect all poles on a cyclical basis in all of LUI's service areas. Project areas are prioritized by the age of the assets to ensure proper safety precautions are taken to upgrade the assets that demand it. Asset information is stored and analyzed with the help of LUI's Geographical Information System (GIS). Capital projects are prioritized using condition assessment data, asset age, reliability, supply and safety considerations, where possible depreciated line replacements are combined with voltage conversions or feeder capacity upgrade/additions. Overhead lines are replaced when alternatives such as maintenance or rehabilitation are not possible or cost effective. The consequences of not proceeding would be allowing the condition of these assets to deteriorate into a state negatively impacting public safety and/ or system reliability

PROJECT DETAIL/ SCOPE:

The scope of these projects included the rebuilding of the overhead distribution that was in poor condition and had reached the end of its life. The Town and Cobourg Public Utility Commission (presently LUI) made the assessment 25 years ago to convert the township from 4Kv to 27.6Kv. The project also facilitated the conversion from 4kv to 27.6kv as part of LUI's Asset Management strategy. Transformers, conductors, poles, guys/anchors, and other equipment were replaced if they were not recoverable.

EXPECTED BENEFITS:

- ✓ Reduced Exposure to safety hazards associated with aged plant and equipment
- ✓ Increased reliability of new plant and materials
- ✓ Increased safety of new design standards and clearances.
- ✓ Increased line capacity/lower line losses from voltage conversions

***PROJECT TITLE*:** William Street

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$ 30, 050

PROJECT VALUE $ 30,050

***PROJECT TITLE*:** Burnham Street & William Street

PROJECT COSTS BY US O A:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$22,301
1835	Overhead Conductors and Devices	$33,956
1850	Line Transformers	$10,274

PROJECT VALUE $ 66,531

***PROJECT TITLE*:** Carlisle Street

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$12, 311
1835	Overhead Conductors and Devices	$21, 998
1850	Line Transformers	$8, 940

PROJECT VALUE $ 43,249

***PROJECT TITLE*:** Curtis Crescent

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$9,394
1835	Overhead Conductors and Devices	$28,577
1850	Line Transformers	$8,855

PROJECT VALUE $ 46,826

***PROJECT TITLE*:** Northwood Drive

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$10,277
1835	Overhead Conductors and Devices	$27,981
1850	Line Transformers	$13,599

PROJECT VALUE $ 51,857

***PROJECT TITLE*:** Westwood Drive North End

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1835	Overhead Conductors and Devices	$31,529
1850	Line Transformers	$6,536

PROJECT VALUE $ 38,065

***PROJECT TITLE*:** William Street ROW - Up to Railroad Tracks

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$42,609
1835	Overhead Conductors and Devices	$65,047
1850	Line Transformers	$37,680

PROJECT VALUE $ 145,336

***PROJECT TITLE*:** Swayne Street

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$13,028
1835	Overhead Conductors and Devices	$38,720
1850	Line Transformers	$50,586

PROJECT VALUE $ 102,335

***PROJECT TITLE*:** Furnace Street

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1835	Overhead Conductors and Devices	$15,265
1850	Line Transformers	$19,700

PROJECT VALUE $ 34,965

2008 RESIDENTIAL EXPANSION PROJECTS

RESIDENTIAL EXPANSION NEED:

LUI's underground residential subdivisions are capital expansions to the LUI distribution system driven solely by customer demand. In accordance with the Distribution System Code, LUI performs economic evaluation for each project and provides the developer with an offer to connect. Developers that meet LUI's conditions of service and provide the necessary financial commitments are connected. Total expenditures vary with the level of economic activity in LUI's service area. The spending for this expansion project is customer driven.

There are no alternatives to proceeding with this customer requested work, and the consequence of not proceeding would result in LUI being in conflict with the Distribution System Code and municipal development objectives.

PROJECT DETAIL/ SCOPE:

This project involves the installation of line transformers to facilitate electrical servicing of new residential developments. Included are new primary cables, transformers, civil infrastructure,

secondary cables, and other necessary plant and equipment. Work is coordinated with developers and other utilities and is completed in accordance with developer's timelines.

EXPECTED BENEFITS:

- ✓ Increased feeder capacity and distribution assets for growth.
- ✓ Expansion of system to connect new customers.

***PROJECT TITLE*:** Palisade Gardens – Chapel Street

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1850	Line Transformers	$35,132

PROJECT VALUE $ 35,132

***PROJECT TITLE*:** Town of Cobourg Darcy Street

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1850	Line Transformers	$46,496

PROJECT VALUE $ 46,496

***PROJECT TITLE*:** 73-77 King Street

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1850	Line Transformers	$27,043

PROJECT VALUE $ 27,043

2008 COMMERCIAL EXPANSION PROJECTS

COMMERCIAL EXPANSION NEED:

LUI's commercial additions are capital expansions to the LUI distribution system driven solely by customer demand. In accordance with the Distribution System Code, LUI performs economic evaluation for each project and provides the developer with an offer to connect. Developers that meet LUI's conditions of service and provide the necessary financial commitments are connected. Total expenditures vary with the level of economic activity in LUI's service area. The spending for this expansion project is customer driven.

There are no alternatives to proceeding with this customer requested work, and the consequence of not proceeding would result in LUI being in conflict with the Distribution System Code and municipal development objectives.

PROJECT DETAIL/ SCOPE:

This project involves the installation of line transformers to facilitate electrical servicing of new commercial developments. Included are new primary cables, transformers, civil infrastructure, secondary cables, and other necessary plant and equipment. Work is coordinated with developers and other utilities and is completed in accordance with developer's timelines.

EXPECTED BENEFITS:

- ✓ Increased feeder capacity and distribution assets for growth.
- ✓ Expansion of system to connect new customers.

***PROJECT TITLE*:** Northumberland Mall – 1111 Elgin Street

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1850	Line Transformers	$27,645

PROJECT VALUE $ 27,645

***PROJECT TITLE*:** Division Street – Tim Horton's / Ultramar Gas Bar

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1850	Line Transformers	$31,987

PROJECT VALUE $ 31,987

***PROJECT TITLE*:** Elgin Street – Mark Work Wear House Development

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1835	Overhead Conductors and Devices	$28,577
1850	Line Transformers	$17,641

PROJECT VALUE $ 46,218

2008 SOFTWARE ADDITION PROJECTS

COMPUTER SOFTWARE NEED:

LUI invested in a Geographic Information System (GIS) to support its business operations. GIS integrates software, hardware, and data for capturing, managing, analyzing and displaying asset information. GIS provides critical tools to organize information and knowledge, make informed decisions, improve communications and increase efficiency of work processes. From its inception much work has been performed in transferring paper based asset data into the GIS data base. LUI currently uses its GIS to assist with engineering design, asset management, supply planning outage planning and budgeting processes. The GIS is constantly being updated and expanded as new assets are installed with new constructions or replacing aged assets and also as new analytical tools are needed. There are plans to integrate the GIS with other enterprise information systems such as outage management, SCADA system and engineering analysis tolls to provide faster, more efficient analysis and respond to power system operational issues.

PROJECT DETAIL/ SCOPE:

The focus for the GIS system investment in 2008 was to continue to build the database of primary and secondary distribution circuits. A number of external tools were implemented to aid in data extraction from the system into the GIS. This is expected to be a continuous project until fully developed and updated.

EXPECTED BENEFITS:

- ✓ Increased efficiency in maintaining information
- ✓ Increased efficiency in accessing information
- ✓ Increased ability to analyze data and develop improvement strategies.
- ✓ Increased ability to report data to internal and external stakeholders.

***PROJECT TITLE*:** Computer Software Upgrades

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1925	Computer Software	$39,145

PROJECT VALUE $ 39,145

2008 TRANSPORTATION ADDITIONS

TRANSPORTATION BUSINESS NEED:

LUI invested in the purchase of a Radial Boom Digger Derrick Truck to assist with underground cable pulls and the installation of poles using the crane feature. It was necessary in 2008 for LUI to purchase a Digger Derrick Truck because of the strong engine capacity, and for assistance with easy installation of poles, overheads and pad transformers. It also helps with the pulling and moving of materials specific to work orders. Digger trucks are used in the utility industry as a means of performing necessary work around the service area. In complying with safety standards the depreciation of a Radial Boom Digger Derrick is 10 years and it is required that LUI update to the new design standards for Asset Management and Employee Safety criterions.

PROJECT DETAIL/ SCOPE:

The focus for the Digger Derrick capital addition in 2008 was to continue being within the safety and standards code. Once a Radial Boom Digger Derrick Truck has fully depreciated an asset assessment evaluation is performed based on asset age, reliability, supply and safety considerations, where possible depreciated trucks are replaced to remain in date with the new model benefits. LUI found the depreciated truck to be out of date and most benefit would result in the acquisition of the Radial Boom Digger Derrick Truck rather than to continue to maintain an older version of this asset.

EXPECTED BENEFITS:

- ✓ Reduced expense of hiring or renting third party equipment.
- ✓ Reduced maintenance expense of older model.
- ✓ Increased safety of new design standards.
- ✓ Increased efficiency of work time capacity.

***PROJECT TITLE*:** Transportation Capital Addition

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1930	Transportation Equipment	$284,467

PROJECT VALUE $ 284,467

LUI 2009 CAPITAL PROJECTS – MATERIALITY > $25,000

Table 2 – 12 2009 Fixed Asset Continuity Schedule

2009 Actual Capital Projects		1610	1808	1820	1830	1835	1840	1845	1850	1855	1860	1915	1920	1925	1930	1940	1995	
	Type of Project	Other	Building & Fixtures	Distribut	Poles, Towers & Fixtures	O/H Cond & Devices	U/G Conduit	U/G Cond & Devic	Line Transforme	Services	Meters	Office Equipme	Computer Hardwar	Computer Softwa	Transportatio n Equipme	Tools & Equipme	Contributions & Grants	Total
William Street	Rebuild / Upgrade				3,319	12,599			1,875									17,793
Burwash Street	Rebuild / Upgrade				9,993													9,993
Hayden Crescent	Rebuild / Upgrade				12,240	15,127			9,966									37,333
Murray Crescent	Rebuild / Upgrade				10,031	12,289			8,489									30,808
Spragge Crescent	Rebuild / Upgrade				7,435													7,435
Harden Crescent	Rebuild / Upgrade				9,500	15,347			2,830									27,676
Harden Street	Rebuild / Upgrade				9,923	15,073			8,319									33,314
Marion Street	Rebuild / Upgrade				4,662	5,120												9,781
Sandra Crescent	Rebuild / Upgrade				3,218	7,291			3,570									14,078
Sinclair Street	Rebuild / Upgrade				20,263	27,966			19,479									67,707
Durham Street	Rebuild / Upgrade				4,675	1,812												6,487
Orange	Rebuild / Upgrade								4,564									4,564
Havelock Street	Rebuild / Upgrade					7,914			4,768									12,682
Furnace Street	Rebuild / Upgrade					29,793			19,701									49,493
John Street South	Rebuild / Upgrade								5,360									5,360
Division & Park	Rebuild / Upgrade								6,858									6,858
Densmore Rd - 3 Phase	Rebuild / Upgrade				6,699	42,803		18,854	1,171									69,526
King Street East	Rebuild / Upgrade								1,294									1,294
VanDyk - Westpark Village	Expansion								57,724	6,241								63,964
LeBlanc - Densmore Rd	Expansion								4,766	1,872								6,638
Colson & Colson - Densmore	Expansion					660			660									1,320
Porter - Brook Meadows	Expansion								10,676	1,722								12,397
Northumberland Cty - 860	Expansion								27,280									27,280
Transformers Capital	Expansion								21,543									21,543
Curtis Subdivision	Expansion						34,372	28,645	10,640	8,184								81,841
New Amherst Subdivision	Expansion						19,106	5,389										24,495
Albert St - Division to Third	Municipal Initiative				2,910	3,233			33,078	5,429								44,650
Ontario Street Elgin to 401	Municipal Initiative					28,075												28,075
Queen Street Division to	Betterment								70,080									70,080
420 King Street Phase 3	Betterment								45,799									45,799
Computer Hardware	Computer Hardware												10,525					10,525
Equipment	Equipment															73,749		73,749
Meters	Meters										15,362							15,362
Office Equipment	Office Equipment											41,318						41,318
Office Renovations	Office Renovations		74,242															74,242
Transportation Equipment	Transportation Equipment														54,788			54,788
Kerr Street and Other	Upgrade			23,373														23,373
Miscellaneous Other Projects	Rebuild / Upgrade	47,200				7,705		3,484	8,309	10,503								77,201
Capital Contributions	Contributions																-100,595	-100,595
ACCOUNT TOTALS		0	74,242	23,373	104,867	225,099	53,478	52,888	380,488	23,448	15,362	41,318	10,525	0	54,788	73,749	0	1,133,625

2009 OVERHEAD REBUILD/UPGRADE CONVERSION PROJECTS

REBUILD/UPGRADE NEED:

LUI has a population of approximately 3,200 overhead line poles. LUI recognizes that the conditions of these assets deteriorate over time and LUI takes a proactive approach to their replacement. Asset Management Programs are put in place to inspect all poles on a cyclical basis in all of LUI's service areas. Project areas are prioritized by the age of the assets to ensure proper safety precautions are taken to upgrade the assets that demand it. Asset information is stored and analyzed with the help of LUI's Geographical Information System (GIS). Capital projects are prioritized using condition assessment data, asset age, reliability, supply and safety considerations, where possible depreciated line replacements are combined with voltage conversions or feeder capacity upgrade/additions. Overhead lines are replaced when alternatives such as maintenance or rehabilitation are not possible or cost effective. The consequences of not proceeding would be allowing the condition of these assets to deteriorate into a state negatively impacting public safety and/ or system reliability

PROJECT DETAIL/ SCOPE:

The scope of these projects included the rebuilding of the overhead distribution that was in poor condition and had reached the end of its life. The Town and Cobourg Public Utility Commission (presently LUI) made the assessment 25 years ago to convert the township from 4Kv to 27.6Kv. The project also facilitated the conversion from 4kv to 27.6kv as part of LUI's Asset Management strategy. Transformers, conductors, poles, guys/anchors, and other equipment were replaced if they were not recoverable.

EXPECTED BENEFITS:

- ✓ Reduced Exposure to safety hazards associated with aged plant and equipment
- ✓ Increased reliability of new plant and materials
- ✓ Increased safety of new design standards and clearances.
- ✓ Increased line capacity/lower line losses from voltage conversions

***PROJECT TITLE*:** Hayden Crescent

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$12,240
1835	Overhead Conductors and Devices	$15,127
1850	Line Transformers	$9,966

PROJECT VALUE $ 37,333

***PROJECT TITLE*:** Murray Crescent

PROJECT COSTS BY US O A:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$10,031
1835	Overhead Conductors and Devices	$12,289
1850	Line Transformers	$8,489

PROJECT VALUE $ 30,808

***PROJECT TITLE*:** Harden Crescent
PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$9,500
1835	Overhead Conductors and Devices	$15,347
1850	Line Transformers	$2,830

PROJECT VALUE $ 27,676

***PROJECT TITLE*:** Harden Street
PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$9,394
1835	Overhead Conductors and Devices	$15,073
1850	Line Transformers	$8,319

PROJECT VALUE $ 33,314

***PROJECT TITLE*:** Sinclair Street
PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$20,263
1835	Overhead Conductors and Devices	$27,966
1850	Line Transformers	$19,479

PROJECT VALUE $ 67,707

***PROJECT TITLE*:** Furnace Street
PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1835	Overhead Conductors and Devices	$29,793
1850	Line Transformers	$19,701

PROJECT VALUE $ 49,493

2009 UNDERGROUND REBUILD/UPGRADE CONVERSION PROJECTS

REBUILD/UPGRADE NEED:

LUI has a population of approximately 3,200 overhead line poles. LUI recognizes that the conditions of these assets deteriorate over time and LUI takes a proactive approach to their replacement. Asset Management Programs are in place to inspect all poles on a cyclical basis in all of LUI's service areas. Asset information is stored and analyzed with the help of LUI's Geographical Information System (GIS). Capital projects are prioritized using condition assessment data, asset age, reliability, supply and safety considerations, where possible depreciated line replacements are combined with voltage conversions or feeder capacity upgrade/additions. Overhead lines are replaced when alternatives such as maintenance or rehabilitation are not possible or cost effective**. In certain circumstances LUI finds it beneficial to replace the overheads lines with underground conductors and devices. Reasons include aesthetic appeal, zoning (subdivision and historical) regulations, and functionality of the lines.** The consequences of not proceeding would allow the condition of these assets to deteriorate into a state negatively impacting public safety and or system reliability.

PROJECT DETAIL/ SCOPE:

The scope of this project included the rebuilding of LUI's subdivisions and promoting the installation of **underground lines** for aesthetic appeal. The Town and Public Utility Commission made the assessment 25 years ago to convert the township from 4Kv to 27.6Kv. The project also facilitated the conversion from 4kv to 27.6 kv as part of LUI's Asset Management strategy. Transformers, conductors, poles, guys/anchors, and other equipment were replaced if they were not recoverable.

EXPECTED BENEFITS:

- ✓ Reduced Exposure to safety hazards associated with aged plant and equipment
- ✓ Increased reliability of new plant and materials
- ✓ Increased safety of new design standards and clearances.
- ✓ Increased line capacity/lower line losses from voltage conversions
- ✓ Increased Aesthetic Appeal

***PROJECT TITLE*:** Densmore Road – 3 Phase

PROJECT COSTSBY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$6,699
1835	Overhead Conductors and Devices	$42,803
1845	Underground Conductors and Devices	$18,854
1850	Line Transformers	$1,171

PROJECT VALUE $ 69,526

2009 RESIDENTIAL EXPANSION PROJECTS

RESIDENTIAL EXPANSION NEED:

LUI's underground residential subdivisions are capital expansions to the LUI distribution system driven solely by customer demand. In accordance with the Distribution System Code, LUI performs economic evaluation for each project and provides the developer with an offer to connect. Developers that meet LUI's conditions of service and provide the necessary financial commitments are connected. Total expenditures vary with the level of economic activity in LUI's service area. The spending for this expansion project is customer driven.

There are no alternatives to proceeding with this customer requested work, and the consequence of not proceeding would result in LUI being in conflict with the Distribution System Code and municipal development objectives.

PROJECT DETAIL/ SCOPE:

This project involves the installation of line transformers to facilitate electrical servicing of new residential developments. The scope of this project included the rebuilding of LUI's subdivisions and promoting the installation of **underground lines** for aesthetic appeal. Included are new primary cables, transformers, civil infrastructure, secondary cables, and other necessary plant and equipment. Work is coordinated with developers and other utilities and is completed in accordance with developer's timelines.

EXPECTED BENEFITS:

- ✓ Increased feeder capacity and distribution assets for growth.
- ✓ Expansion of system to connect new customers.

***PROJECT TITLE*:** Curtis Subdivision

PROJECT DESCRIPTION COSTS BY USOA:

USoA	Description	TOTAL VALUE
1840	Underground Conduit	$34,372
1845	Underground Conductors and Devices	$28,645
1850	Line Transformers	$10,640
1855	Services	$8,184

PROJECT VALUE $ 81,841

***PROJECT TITLE*:** Northumberland County – 860 William Street

PROJECT DESCRIPTION COSTS BY USOA:

USoA	Description	TOTAL VALUE
1850	Line Transformers	$27,280

PROJECT VALUE $ 27,280

***PROJECT TITLE*:** VanDyke – Westpark Village

PROJECT DESCRIPTION COSTS BY USOA:

USoA	Description	TOTAL VALUE
1850	Line Transformers	$57,724
1855	Services	$6,241

PROJECT VALUE $ 63,964

2009 BETTERMENT/ADVANCEMENT PROJECTS

CAPITAL ADVANCEMENT NEED:

Betterment and advancement community projects include the expenditures incurred to relocate and replace poles, lines, and transformers that conflict with the city planning reconstruction activities. The Town of Cobourg has deemed these projects as preserved heritage streets within our service territory. This means that all above ground lines must be converted to the 27.6 Kv extension using underground lines. The spending budgets are driven by activities of road authorities and township specifications for the projects are rarely known at the time of development and planning. There are no alternative to these activities. These expenditures are not discretionary as compliance is mandated by the Town of Cobourg, and Cramahe Township.

PROJECT DETAIL/ SCOPE:

This work includes the removal of all existing poles, conductors, transformers, guying and all other equipment within the road authority's scope of work and construction standards at an alternate locations. LUI realizes that there are reduced benefits to relocating existing lines, and makes best effort to recover the materials and the remaining life of the asset to avoid the cost of the purchase materials.

EXPECTED BENEFITS:

- ✓ Reduced Exposure to safety hazards associated with aged plant and equipment
- ✓ Increased reliability of new plant and materials
- ✓ Increased safety of new design standards and clearances.
- ✓ Increased line capacity/lower line losses from voltage conversions

***PROJECT TITLE*:** 420 King Street – Phase 3

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1850	Line Transformers	$45,799

PROJECT VALUE $ 70,080

***PROJECT TITLE*:** Queen Street from Division Street to Church Street

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1850	Line Transformers	$70,080

PROJECT VALUE $ 70,080

2009 MUNICIPAL CAPITAL PROJECTS

MUNICIPAL CAPITAL NEED:

Municipal Initiative Projects include the expenses to relocate and replace poles, lines, and transformers that conflict with city planning reconstruction activities. The Town requests specific work to be done that requires LUI's services to remove and reinstall certain aspects of our distribution infrastructure so that they may gain access for their own purposes (i.e: road expansion, sidewalk restoration). The spending budgets are driven by activities of road authorities and townships specifications for the projects are rarely known at the time of development and planning. There are no alternatives to these activities. These expenditures are not discretionary as compliance is mandated by the Town of Cobourg, and Cramahe Township and Public Service Works on Highways Act R.S.O 1990. In efforts to make these projects cost effective, during time of removal LUI assesses the benefits of converting these areas with upgraded system assets due to building a new substation.

PROJECT DETAIL/ SCOPE:

This work includes the removal of all existing poles, conductors, transformers, guying and all other equipment within the road authority's scope of work and construction standards at an alternate locations. LUI realizes that there are reduced benefits to relocating existing lines, and makes best effort to recover the materials and the remaining life of the asset to avoid the cost of the purchase materials.

EXPECTED BENEFITS:

- ✓ Reduced Exposure to safety hazards associated with aged plant and equipment
- ✓ Increased reliability of new plant and materials
- ✓ Increased safety of new design standards and clearances.
- ✓ Increased line capacity/lower line losses from voltage conversions

***PROJECT TITLE*:** Albert Street – Division to Third

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$2,910
1835	Overhead Conductors and Devices	$3,233
1850	Line Transformers	$33,078
1855	Services	$5,429

PROJECT VALUE $ 44,650

***PROJECT TITLE*:** Ontario Street – Elgin Street to 401 Bridge

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1835	Overhead Conductors and Devices	$28,075

PROJECT VALUE $ 28,075

2009 OFFICE CAPITAL PROJECTS

OFFICE CAPITAL NEED:

LUI developed an office improvement plan due to the aging capital in its office workplace. LUI experienced lack of office space, and because of the addition of new staff in the finance and human resources department LUI was required to renovate its building office space to accommodate these individuals. Not only did LUI require the expansion of its building LUI also required proper workspace equipment and invested in the purchase of office furniture. In 2009 LUI purchased new chairs for its employees to comply with employee ergonomics standards and to provide proper updated working desks, as the older equipment was not practical, and consumed too much space for a growing company. In addition to the above project the Operations Work Center (OWC) also required the addition of two office spaces for the field service representatives and the increasing lack of space because it's holding of inventory and operational materials.

PROJECT DETAIL/ SCOPE:

LUI's scope for office renovations was to create more space and LUI was required to economically maximize its building's space. LUI performed this project by analyzing the costs between various options. LUI was required to perform cost benefit analysis on the purchase of a new building, or create additions to the existing building, while reconfiguring the current workspace. LUI decided on a combination of these options and purchased new equipment, reconfigured its office space, and performed a small renovation to reduce the copier room space and add an office space. More benefits were found from this solution for asset management planning.

EXPECTED BENEFITS:

- ✓ Better performance from employees overall.
- ✓ Increased ergonomic safety of new design standards.
- ✓ Increased efficiency of work time capacity.
- ✓ Appropriate business standard cubicles.

***PROJECT TITLE*:** Office Renovation Project

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1915	Office Equipment	$41,318
1808	Building and Fixtures	$74,242

PROJECT VALUE $ 115,560

2009 TRANSPORTATION CAPITAL PROJECTS

BUSINESS TRANSPORTATION NEED:

LUI invested in the purchase of a two trucks, one of which is a replacement and the other being an addition to LUI's vehicle fleet. LUI had a business need for the vehicles so that employees were able to better respond to calls in the field. It was necessary in 2009 for LUI to purchase these line trucks because of the capacity required to carry the equipment with ease. These trucks are used in the utility industry as a means of performing necessary work around the service area. In complying with safety standards the depreciation of the company vehicles are 10 years and it is necessary that LUI update to the new design standards for employee safety criterions. LUI has determined that these time frames represent the most cost efficient schedules and that to extend beyond these timeframes it incurs increased maintenance costs and reduced fleet reliability.

PROJECT DETAIL/ SCOPE:

This project includes all costs associated with developing the specifications for the vehicles; completing the tendering process; ordering the vehicle; inspecting the engine and body during assessment and purchase of the truck; and commissioning the completed truck into LUI's fleet and at LUI's facility (installing signage and high visibility striping, two way radio system, registering the truck with MTO, completing an in-service training session for our drivers, etc.). The focus for the capital additions of company trucks was to continue to be within the safety and standards code. Once the trucks have fully depreciated an asset assessment evaluation is performed based on asset age, reliability, supply and safety considerations, where possible depreciated trucks are replaced to remain in date with the new model benefits

EXPECTED BENEFITS:

- ✓ Reduced maintenance expense of older model.
- ✓ Increased safety of new design standards.
- ✓ Increased efficiency of work time capacity.

PROJECT TITLE: Transportation Capital Addition and Replacement

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1930	Transportation Equipment	$54,788

PROJECT VALUE $ 54,788

2009 BUSINESS EQUIPMENT CAPITAL PROJECTS

BUSINESS EQUIPMENT NEED:

During the year of 2009 LUI invested in the purchases of:

- Voltage Detector - Which is used for testing meters
- Storage Tree – Which is used to install wire
- Rubber Blankets – Which are used to safely cover live wires and provide a safe work environment
- Analyzer – Which is used for equipment testing of meters
- Metric measuring wheel- Which is used for measuring accurate distance
- Ball Clevis- Which is used for the stringing of wires
- 6 ton and 12 ton Press –Which is used for installing connectors to Wire

LUI increased capital work due to the conversion of its service area from 4Kv to 27.6Kv as well as the expansion of subdivisions in LUI's region. With this increased capital work LUI required purchases of additional operational materials and equipment. LUI's regular business needs necessitate proper and safe equipment to perform daily work orders in the field without interruption due to ineffective equipment.

PROJECT DETAIL/ SCOPE:

LUI intends to promote a safe and secure workplace, and due to the nature of utility service work it is necessary to provide employees with up to date and efficient tools to complete their day-to-day work. The scope of these equipment additions are to complete all assignments while recognizing the increase in demand due to conversion and expansion LUI purchased the equipment necessary to provide safe and beneficial capital equipment for the use of its employees.

EXPECTED BENEFITS:

- ✓ Reduced maintenance expense of older model.
- ✓ Increased safety of new design standards.
- ✓ Increased efficiency of work time capacity.

***PROJECT TITLE*:** Equipment

PROJECT COSTSBY USOA:

USoA	Description	TOTAL VALUE
1940	Tools & Equipment	$73,749

PROJECT VALUE $ 73,749

Table 2-14 2010 Fixed Asset Continuity Schedule

CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1610	Intangible Assets	600,064		545,198	54,866	0			0	54,866
N/A	1805	Land	219,284	0		219,284	0			0	219,284
CEC	1806	Land Rights	0			0	0			0	0
47	1808	Buildings and Fixtures	862,119	57,097		919,216	98,905	19,878		118,783	800,433
13	1810	Leasehold Improvements	0			0	0			0	0
47	1815	Transformer Station Equipment - Normally Primary	0			0	0			0	0
47	1820	Distribution Station Equipment - Normally Primary	2,774,813	22,514	35,093	2,762,235	1,543,908	90,027	35,093	1,598,842	1,163,393
47	1825	Storage Battery Equipment	0			0	0			0	0
47	1830	Poles, Towers and Fixtures	805,335	301,976		1,107,311	126,195	38,253		164,448	942,863
47	1835	Overhead Conductors and Devices	3,565,181	248,573		3,813,754	490,657	271,145		761,802	3,051,952
47	1840	Underground Conduit	499,541	379,402		878,943	145,674	28,340		174,014	704,929
47	1845	Underground Conductors and Devices	2,872,314	193,840		3,066,154	1,702,354	117,601		1,819,955	1,246,199
47	1850	Line Transformers	4,780,641	330,408		5,111,049	2,011,895	192,821		2,204,716	2,906,333
47	1855	Services	453,103	56,426		509,529	123,725	18,767		142,492	367,037
47	1860	Meters	890,316	4,147		894,462	495,851	35,429		531,280	363,183
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights	0			0	0			0	0
47	1908	Buildings and Fixtures	0			0	0			0	0
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	107,816	13,957	64,747	57,026	57,928	14,153	64,747	7,334	49,692
10	1920	Computer Equipment - Hardware	117,818	8,308	94,926	31,199	100,224	7,407	94,926	12,705	18,494
12	1925	Computer Software	66,132	47,744		113,876	28,333	18,001		46,334	67,542
10	1930	Transportation Equipment	585,222	364,617	190,134	759,705	229,806	110,201	190,134	149,873	609,831
8	1935	Stores Equipment	0			0	0			0	0
8	1940	Tools, Shop and Garage Equipment	158,730			158,730	48,849			48,849	109,881
8	1945	Measurement and Testing Equipment	0	18,712		18,712	0	936		936	17,776
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	0
8	1960	Miscellaneous Equipment	0			0	0			0	0
47	1970	Load Management Controls - Customer Premises	0			0	0			0	0
47	1975	Load Management Controls - Utility Premises	0			0	0			0	0
47	1980	System Supervisory Equipment	0			0	0			0	0
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(1,601,978)	(555,681)		(2,157,659)	(301,163)	(68,886)		(370,049)	(1,787,610)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**17,756,449**	**1,492,040**	**930,098**	**18,318,391**	**6,903,141**	**894,073**	**384,900**	**7,412,314**	**10,906,077**
WIP		Work in Process	0			0	0			0	0
		Total after Work in Process	**17,756,449**	**1,492,040**	**930,098**	**18,318,391**	**6,903,141**	**894,073**	**384,900**	**7,412,314**	**10,906,077**

2010 Actual Capital Projects (exceeding threshold)

The following Table 2-15 provides LUI's capital additions, exceeding the materiality threshold of $25,000, by project, project type and USoA as well as the total projects, by USoA that fall under the materiality threshold.

Table 2-15 2010 Actual Capital Projects

LUI 2010 CAPITAL PROJECTS – MATERIALITY > $25,000

2010 Actual Capital Projects		1808	1820	1830	1835	1840	1845	1850	1855	1860	1915	1920	1925	1930	1945	1995	
	Type of Project	Building & Fixtures	Distribution Station	Poles, Towers & Fixtures	O/H Cond & Devices	U/G Conduit	U/G Cond & Devices	Line Transformers	Services	Meters	Office Equipment	Computer Hardware	Computer Software	Transportation Equipment	Measurement Equip	Contributions & Grants	Total
Orange Street	Rebuild / Upgrade			13,358	23,219			4,565									41,141
Carlisle	Rebuild / Upgrade			2,816													2,816
Maguire Street	Rebuild / Upgrade			48,997	60,927			12,047									121,971
Queen Street	Rebuild / Upgrade					116,188	25,319	73,317									214,824
Albert Street	Rebuild / Upgrade			2,910		91,641	8,662	33,078									136,291
Burnham, William to Heath	Rebuild / Upgrade			2,894													2,894
William Street	Rebuild / Upgrade			2,903	10,408			884									14,195
University Street	Rebuild / Upgrade			392													392
Burnham, Heath - Westwood	Rebuild / Upgrade			50,968													50,968
Spragge Street	Rebuild / Upgrade				15,358												15,358
Densmore Rd - 3 Phase	Rebuild / Upgrade				7,202												7,202
Curtis Subdivision	Expansion				2,507	146,330	99,717	44,637	36,399								329,590
Westpark Village Phase 2C	Expansion					13,172	2,807	1,727									17,707
Westpark Village Phase 3A	Expansion					9,186	3,827	2,041									15,055
New Amherst	Expansion						33,545										33,545
ODC - Weston	Expansion			21,083	14,623												35,707
Parkview Hills	Expansion							16,367	12,316								28,683
KPR -Burnham PS	Expansion							7,332									7,332
VanDyk - Carlisle	Expansion					2,693											2,693
VanDyk - Westpark Village	Expansion								2,801								2,801
Porter - Brook Meadows Brook Rd	Expansion								2,815								2,815
LeBlanc - Densmore Rd	Expansion						9,459	17,459	940								27,858
691 King St West - Stallwood Homes	Expansion							10,930									10,930
323 George St	Expansion							28,982									28,982
Distribution Stn <50KV	Equipment		22,514														22,514
Darcy St - Community Centre	Municipal Initiative			145,830	114,180		7,619	73,635									341,264
Capital 09 Albert to Third	Municipal Initiative						1,809										1,809
Measurement Equipment	Measurement Equipment														18,712		18,712
Meters	Meters									4,147							4,147
Office Equipment	Office Equipment										13,957						13,957
Office Upgrades	Office Upgrades	57,097															57,097
Software	Software												47,744				47,744
Hardware	Hardware											8,308					8,308
Transportation Equip	Transportation Equip													364,617			364,617
Miscellaneous Other Projects	Rebuild / Upgrade			9,824	149	193	1,074	3,407	1,154								15,801
Capital Contributions																-555,681	-555,681
ACCOUNT TOTALS		**57,097**	**22,514**	**155,654**	**114,329**	**193**	**10,503**	**77,042**	**1,154**	**4,147**	**13,957**	**8,308**	**47,744**	**364,617**	**18,712**	**-555,681**	**340,288**

2010 OVERHEAD REBUILD/UPGRADE CONVERSION PROJECTS

REBUILD/UPGRADE NEED:

LUI has a population of approximately 3,200 overhead line poles. LUI recognizes that the conditions of these assets deteriorate over time and LUI takes a proactive approach to their replacement. Asset Management Programs are put in place to inspect all poles on a cyclical basis in all of LUI's service areas. Project areas are prioritized by the age of the assets to ensure proper safety precautions are taken to upgrade the assets that demand it. Asset information is stored and analyzed with the help of LUI's Geographical Information System (GIS). Capital projects are prioritized using condition assessment data, asset age, reliability, supply and safety considerations, where possible depreciated line replacements are combined with voltage conversions or feeder capacity upgrade/additions. Overhead lines are replaced when alternatives such as maintenance or rehabilitation are not possible or cost effective. The consequences of not proceeding would be allowing the condition of these assets to deteriorate into a state negatively impacting public safety and/ or system reliability

PROJECT DETAIL/ SCOPE:

The scope of these projects included the rebuilding of the overhead distribution that was in poor condition and had reached the end of its life. The Town and Cobourg Public Utility Commission (presently LUI) made the assessment 25 years ago to convert the township from 4Kv to 27.6Kv. The project also facilitated the conversion from 4kv to 27.6kv as part of LUI's Asset Management strategy. Transformers, conductors, poles, guys/anchors, and other equipment were replaced if they were not recoverable.

EXPECTED BENEFITS:

- ✓ Reduced Exposure to safety hazards associated with aged plant and equipment
- ✓ Increased reliability of new plant and materials
- ✓ Increased safety of new design standards and clearances.
- ✓ Increased line capacity/lower line losses from voltage conversions

***PROJECT TITLE*:** Orange Street

PROJECT COSTSBY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$13,358
1835	Overhead Conductors and Devices	$23,219
1850	Line Transformers	$4,565

PROJECT VALUE $ 41,141

***PROJECT TITLE*:** Burnham Heath Westwood

PROJECT COSTSBY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$50,968

PROJECT VALUE $ 50,968

***PROJECT TITLE*:** Maguire Street

PROJECT COSTSBY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$48,997
1835	Overhead Conductors and Devices	$60,927
1850	Line Transformers	$12,047

PROJECT VALUE $ 121,971

2010 UNDERGROUND REBUILD/UPGRADE CONVERSION PROJECTS

REBUILD/UPGRADE NEED:

LUI has a population of approximately 3,200 overhead line poles. LUI recognizes that the conditions of these assets deteriorate over time and LUI takes a proactive approach to their replacement. Asset Management Programs are in place to inspect all poles on a cyclical basis in all of LUI's service areas. Asset information is stored and analyzed with the help of LUI's Geographical Information System (GIS). Capital projects are prioritized using condition assessment data, asset age, reliability, supply and safety considerations, where possible depreciated line replacements are combined with voltage conversions or feeder capacity upgrade/additions. Overhead lines are replaced when alternatives such as maintenance or rehabilitation are not possible or cost effective**. In certain circumstances LUI finds it beneficial to replace the overheads lines with underground conductors and devices. Reasons include aesthetic appeal, zoning (subdivision and historical) regulations, and functionality of the lines.** The consequences of not proceeding would allow the condition of these assets to deteriorate into a state negatively impacting public safety and or system reliability.

PROJECT DETAIL/ SCOPE:

The scope of this project included the rebuilding of LUI's subdivisions and promoting the installation of **underground lines** for aesthetic appeal. The Town and Public Utility Commission made the assessment 25 years ago to convert the township from 4Kv to 27.6Kv. The project also facilitated the conversion from 4kv to 27.6 kv as part of LUI's Asset Management strategy. Transformers, conductors, poles, guys/anchors, and other equipment were replaced if they were not recoverable.

EXPECTED BENEFITS:

- ✓ Reduced Exposure to safety hazards associated with aged plant and equipment
- ✓ Increased reliability of new plant and materials
- ✓ Increased safety of new design standards and clearances.
- ✓ Increased line capacity/lower line losses from voltage conversions
- ✓ Increased Aesthetic Appeal

***PROJECT TITLE*:** Queen Street

PROJECT COSTSBY USOA:

USoA	Description	TOTAL VALUE
1840	Underground Conduit	$116,188
1835	Underground Conduit and Devices	$25,319
1850	Line Transformers	$73,317

PROJECT VALUE $ 214, 824

***PROJECT TITLE*:** Albert Street

PROJECT COSTSBY USOA:

USoA	Description	TOTAL VALUE
1840	Underground Conduit	$91,640
1835	Underground Conduit and Devices	$8,662
1830	Poles, Towers, & Fixtures	$2,910
1850	Line Transformers	$33,078

PROJECT VALUE $ 136,291

2010 RESIDENTIAL EXPANSION PROJECTS

RESIDENTIAL EXPANSION NEED:

LUI's underground residential subdivisions are capital expansions to the LUI distribution system driven solely by customer demand. In accordance with the Distribution System Code, LUI performs economic evaluation for each project and provides the developer with an offer to connect. Developers that meet LUI's conditions of service and provide the necessary financial commitments are connected. Total expenditures vary with the level of economic activity in LUI's service area. The spending for this expansion project is customer driven.

There are no alternatives to proceeding with this customer requested work, and the consequence of not proceeding would result in LUI being in conflict with the Distribution System Code and municipal development objectives.

PROJECT DETAIL/ SCOPE:

The scope of this project included the rebuilding of LUI's subdivisions and promoting the installation of **underground lines** for aesthetic appeal. This project involves the installation of a substation to facilitate electrical servicing of new residential developments. Included are new primary cables, transformers, civil infrastructure, secondary cables, and other necessary plant and equipment. Work is coordinated with developers and other utilities and is completed in accordance with developer's timelines.

EXPECTED BENEFITS:

- ✓ Increased feeder capacity and distribution assets for growth.
- ✓ Expansion of system to connect new customers.

***PROJECT TITLE*:** Curtis Subdivision

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1835	Overhead Conductors and Devices	$2,507
1840	Underground Conduit	$146,330
1845	Underground Conductors and Devices	$99,717
1850	Line Transformers	$44,637
1855	Services	$36,399

PROJECT VALUE $ 329,590

***PROJECT TITLE*:** New Amherst – Subdivision

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1845	Underground Conductors and Devices	$33,545

PROJECT VALUE $ 33,545

***PROJECT TITLE*:** ODC Weston – Subdivision

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$21,083
1835	Overhead Conductors and Devices	$14,623

PROJECT VALUE $ 35,707

***PROJECT TITLE*:** Parkview Hills

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1850	Line Transformers	$16,367
1855	Services	$12,316

PROJECT VALUE $ 28,683

***PROJECT TITLE*:** LeBlanc Densmore Road

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1845	Underground Conductors and Devices	$9,459
1850	Line Transformers	$17,459
1855	Services	$940

PROJECT VALUE $ 27,858

***PROJECT TITLE*:** 323 George Street

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1850	Line Transformers	$28,982

PROJECT VALUE $ 28,982

2010 MUNICIPAL CAPITAL PROJECTS

MUNICIPAL CAPITAL NEED:

Municipal Initiative Projects include the expenses to relocate and replace poles, lines, and transformers that conflict with city planning reconstruction activities. The Town requests specific work to be done that requires LUI's services to remove and reinstall certain aspects of our distribution infrastructure so that they may gain access for their own purposes (i.e: road expansion, sidewalk restoration). The spending budgets are driven by activities of road authorities and townships specifications for the projects are rarely known at the time of development and planning. There are no alternatives to these activities. These expenditures are not discretionary as compliance is mandated by the Town of Cobourg, and Cramahe Township and Public Service Works on Highways Act R.S.O 1990. In efforts to make these projects cost effective, during time of removal LUI assesses the benefits of converting these areas with upgraded system assets due to building a new substation.

PROJECT DETAIL/ SCOPE:

This work includes the removal of all existing poles, conductors, transformers, guying and all other equipment within the road authority's scope of work and construction standards at an alternate locations. The scope of this project included the rebuilding of LUI's subdivisions and promoting the installation of **underground lines** for aesthetic appeal. LUI realizes that there are reduced benefits to relocating existing lines, and makes best effort to recover the materials and the remaining life of the asset to avoid the cost of the purchase materials.

EXPECTED BENEFITS:

- ✓ Reduced Exposure to safety hazards associated with aged plant and equipment
- ✓ Increased reliability of new plant and materials
- ✓ Increased safety of new design standards and clearances.
- ✓ Increased line capacity/lower line losses from voltage conversions

***PROJECT TITLE*:** Darcy Street – Community Center

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$145,830
1835	Overhead Conductors and Devices	$114,180
1845	Underground Conduit & Devices	$7,619
1850	Line Transformers	$73,635

PROJECT VALUE $ 341, 264

2010 TRANSPORTATION CAPITAL PROJECTS

TRANSPORTATION BUSINESS NEED:

LUI maintains its fleet of vehicles to achieve a typical useful life of 8-10 years for our company trucks. LUI has determined that these time frames represent the most cost efficient replacement schedule and that to extend beyond these timeframes it incurs increased maintenance costs and reduced fleet reliability. LUI replaced the chassis, cab and powertrain for its double bucket truck.

PROJECT DETAIL/ SCOPE:

This project includes all costs associated with developing the specification documents for the truck chassis, work platform, and truck body; completing the tendering process; ordering the vehicle; inspecting the work platform and body during any fabrications and assembly of the truck; and commissioning the completed truck to our fleet at our facility (installing signage and high visibility striping, two way radio system, registering the truck with MTO, completing an in service training session for our drivers, etc.) For this truck replacement LUI has specified a Chassis and Cab for two of our vehicles.

EXPECTED BENEFITS:

- ✓ Reduced maintenance expense of older model.
- ✓ Increased safety of new design standards.
- ✓ Increased efficiency of work time capacity.
- ✓ Larger truck has the ability to reach higher poles than the previous.

***PROJECT TITLE*:** Transportation Capital Upgrade

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1930	Transportation Equipment	$364,617

PROJECT VALUE $ 364,617

2010 SOFTWARE ADDITION PROJECTS

SOFTWARE ADDITION NEED:

In 2010 LUI began implementing Springboard which is an employee training software tool to support its business operations. Utility businesses have a wide range of employees who are not always able to commit to large training meetings without sacrificing customer service. Springboard integrates software, and creates a static data base for capturing and managing company policies including WSIB training that require employees' attention. Springboard provides critical tools to organize information and knowledge, make informed decisions, improve communications and increase efficiency of work processes. From its inception much work has been performed in transferring paper based policies into an online data base. LUI currently uses its Springboard to provide employees with access to any information that is necessary to perform their professions in a location that is accessible from anywhere that has internet. The Springboard database is constantly being updated and expanded as new issues, and subjects are brought to LUI's attention. Most importantly Springboard includes the safety policies that are often updated. Management is also able to measure the completed level of training online that employees are required to complete, and provide guidance to their employees while evaluating their understanding.

PROJECT DETAIL/ SCOPE:

The focus for the Springboard implementation was to continue to build an accessible database of company information while adapting to employee schedules. Springboard will result in higher productivity and better customer service.

EXPECTED BENEFITS:

- ✓ Increased efficiency in maintaining information
- ✓ Increased efficiency in accessing information
- ✓ Increased flexibility to analyze policies and develop improvement strategies.
- ✓ Increased ability to communicate issues/accomplishments throughout the company.

***PROJECT TITLE*:** Computer Software Upgrades

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1925	Computer Software	$47,744

PROJECT VALUE $ 47,744

2010 OFFICE CAPITAL PROJECTS

BUSINESS CAPITAL NEED:

LUI had to acknowledge fully depreciated assets in the year 2010 for its building and fixtures. To continue with LUI's plan and following the asset management tool, LUI recognized the business need to replace many outdated aspects of the building as well as its fixtures. LUI operates its services from a building that is a historical feature in the Town of Cobourg, and requires particular consideration of its heritage community while attempting to keep up to date with its Conservation Demand Initiatives. LUI also noted while undertaking the CDM Initiatives that it's Operation Work Centre also required updating in certain aspects such as lighting, and water conservation, and heating efficiency.

PROJECT DETAIL/ SCOPE:

LUI's scope for the Building and Fixture upgrades was to create an office place that was more efficient and to create more space while preserving the historic nature of its building. LUI performed necessary upgrades to its building while preserving the historic nature of the building, by installing updated furnaces, upgrading the lighting, upgrading wiring for the new office equipment in 2009. LUI renovated its washrooms to be more efficient and cost effective. LUI was also able to create more space for its new CDM office by purchasing proper storage for the new scanner room, and filing cabinets for its historical records.

EXPECTED BENEFITS:

- ✓ Better work conditions for employees.
- ✓ Increased workspace in the office.
- ✓ Increased efficiency of the buildings heat, and electricity.
- ✓ Removal of outdated and potentially unsafe building aspects.
- ✓ Conservation Demand Management

***PROJECT TITLE*:** Building and Fixture Upgrades

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1808	Buildings and Fixtures	$57,097

PROJECT VALUE $ 57,097

2011 Bridge Year Capital Additions

The 2011 Bridge Year Fixed Asset Continuity Schedule, Table 2-17 provides a summary of the additions and disposals based on the OEB USoA classification. This schedule may also be found in LUI's Revenue Requirement Model attached to this Application.

Table 2-16 2011 Bridge Year Fixed Asset Continuity Schedule

CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1610	Intagible Assets	54,866		54,866	0	0			0	0
N/A	1805	Land	219,284			219,284	0			0	219,284
CEC	1806	Land Rights	0			0	0			0	0
47	1808	Buildings and Fixtures	919,216	75,000		994,216	118,783	21,199		139,982	854,234
13	1810	Leasehold Improvements	0			0	0			0	0
47	1815	Transformer Station Equipment - Normally Primar	0			0	0			0	0
47	1820	Distribution Station Equipment - Normally Primary	2,762,235	800,000		3,562,235	1,598,842	134,928		1,733,771	1,828,465
47	1825	Storage Battery Equipment	0			0	0			0	0
47	1830	Poles, Towers and Fixtures	1,107,311	300,000		1,407,311	164,448	50,293		214,741	1,192,571
47	1835	Overhead Conductors and Devices	3,813,754	230,000		4,043,754	761,802	271,121		1,032,923	3,010,831
47	1840	Underground Conduit	878,943	200,000		1,078,943	174,014	39,928		213,943	865,000
47	1845	Underground Conductors and Devices	3,066,154			3,066,154	1,819,955	121,478		1,941,432	1,124,721
47	1850	Line Transformers	5,111,049	240,000		5,351,049	2,204,716	203,914		2,408,631	2,942,418
47	1855	Services	509,529	30,000		539,529	142,492	20,495		162,987	376,542
47	1860	Meters	894,462	20,000	688,736	225,726	531,280	35,443	409,085	157,638	68,089
47	1860	Smart Meters	1,566,824	255,355		1,822,179	130,791	112,967		243,758	1,578,421
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights	0			0	0			0	0
47	1908	Buildings and Fixtures	0			0	0			0	0
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	57,026	25,000		82,026	7,334	6,953		14,286	67,739
10	1920	Computer Equipment - Hardware	31,199	50,000		81,199	12,705	11,240		23,945	57,254
12	1925	Computer Software	113,876	50,000		163,876	46,334	27,378		73,712	90,164
12	1925	Computer software - Smart Meter	115,160	8,546		123,706	28,589	23,887		52,475	71,231
10	1930	Transportation Equipment	759,705			759,705	149,873	94,963		244,837	514,868
8	1935	Stores Equipment	0			0	0			0	0
8	1940	Tools, Shop and Garage Equipment	158,730	75,000		233,730	48,849	18,931		67,780	165,950
8	1945	Measurement and Testing Equipment	18,712			18,712	936	1,871		2,807	15,905
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	0
8	1960	Miscellaneous Equipment	0			0	0			0	0
47	1970	Load Management Controls - Customer Premises	0			0	0			0	0
47	1975	Load Management Controls - Utility Premises	0			0	0			0	0
47	1980	System Supervisory Equipment	0			0	0			0	0
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(2,157,659)	(100,000)		(2,257,659)	(370,049)	(69,693)		(439,742)	(1,817,917)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**20,000,375**	**2,258,901**	**743,602**	**21,515,673**	**7,571,693**	**1,127,296**	**409,085**	**8,289,904**	**13,225,770**
WIP		Work in Process	0			0	0			0	0
		Total after Work in Process	**20,000,375**	**2,258,901**	**743,602**	**21,515,673**	**7,571,693**	**1,127,296**	**409,085**	**8,289,904**	**13,225,770**

2011 Bridge Year Capital Projects

The following Table 2-18 provides LUI's capital additions by project, project type and USoA for the 2011 Bridge Year.

LUI 2011 CAPITAL PROJECTS – MATERIALITY > $25,000

Table 2-17 2011 Bridge Year Capital Projects

2011 Forecast Capital Projects		1808	1820	1830	1835	1840	1845	1850	1852/1855	1860	1860	1915	1920	1925	1930	1940	1995	
	Type of Project	Building & Fixtures	Distribution Station	Poles, Towers & Fixtures	O/H Cond & Devices	U/G Conduit	U/G Cond & Devices	Line Transformers	Services	Meters	SMART METERS	Office Equipment	Computer Hardware	Computer Software	Transportation Equipment	Tools & Equipment	Contributions & Grants	Total
Blake Street	Rebuild / Upgrade			5,000	37,972			5,098										48,070
Burke Street	Rebuild / Upgrade			15,000	37,386			5,359										57,746
White Street	Rebuild / Upgrade			80,000	30,000			10,000										120,000
Burnham Street	Rebuild / Upgrade			70,000				15,000										85,000
Charles Street	Rebuild / Upgrade					45,000	10,000	15,000										70,000
Havelock Street	Rebuild / Upgrade			20,000	18,421			10,195										48,616
Mathew Street	Rebuild / Upgrade			32,000	54,063			15,293										101,356
Victoria Street	Rebuild / Upgrade			25,000	27,265			5,000										57,265
William Street	Rebuild / Upgrade			25,000	46,803			8,120										79,923
Kerr Street	Rebuild / Upgrade			95,000	124,990			10,195										230,185
Ball Street	Rebuild / Upgrade			10,000	4,917			522										15,439
Buchanan Street	Rebuild / Upgrade			50,000	56,838			16,397										123,235
Bond Street	Rebuild / Upgrade				9,424													9,424
Burwash Street	Rebuild / Upgrade			4,047														4,047
Darcy Street	Rebuild / Upgrade			1,050														1,050
Ewart Street Bell Roger Tower	Rebuild / Upgrade			2,821	3,379													6,200
Maquire Street - Victoria Street	Rebuild / Upgrade			350	20,475													20,825
Weston Street	Rebuild / Upgrade			450														450
Queen Street	Rebuild / Upgrade			5,000														5,000
Orange Street	Rebuild / Upgrade			2,282														2,282
National Car Rental- Ontario Street	Commercial Customer Upgrade				2,878			24,387										27,265
Ontario/Victoria Distr. Station	Distribution Rebuild/Upgrade		60,500															60,500
Brook Rd Distribution Station	Distribution Rebuild/Upgrade		62,500															62,500
Four Line Reclosers	Distribution Upgrade				100,000													100,000
Ewart Street Extension	Expansion							10,000	60,000									70,000
Westpark Village Phase 2C	Residential Expansion			2,000		5,628	1,219	469		750								10,067
Westpark Village Phase 3A	Residential Expansion			5,000		3,401	1,457	777		874								11,510
VanDyk - Westpark Village	Residential Expansion								1,576									1,576
Porter - Brook Meadows Brook Rd	Residential Expansion								479									479
New Amherst Phase 3	Residential Expansion								121									121
New Amherst Phase 3	Residential Expansion				1,122			8,763	844									10,730
Meters	Upgrades									6,000	255,550							261,550
Overhead Upgrades	Upgrades				15,352													15,352
GIS handhelds	Upgrades															55,000		55,000
Miscellaneous Other Projects	Rebuild / Upgrade	75,000				20,000	20,000	20,000	20,000	12,594		20,000	50,000	50,000	8,546	20,000		316,140
Contribution Grants																	-100,000	-100,000
ACCOUNT TOTALS		75,000	123,000	450,000	591,285	74,029	32,677	180,576	83,020	20,219	255,550	20,000	50,000	50,000	8,546	75,000	-100,000	1,988,901

2011 OVERHEAD REBUILD/UPGRADE CONVERSION PROJECTS

REBUILD/UPGRADE NEED:

LUI has a population of approximately 3,200 overhead line poles. LUI recognizes that the conditions of these assets deteriorate over time and LUI takes a proactive approach to their replacement. Asset Management Programs are put in place to inspect all poles on a cyclical basis in all of LUI's service areas. Project areas are prioritized by the age of the assets to ensure proper safety precautions are taken to upgrade the assets that demand it. Asset information is stored and analyzed with the help of LUI's Geographical Information System (GIS). Capital projects are prioritized using condition assessment data, asset age, reliability, supply and safety considerations, where possible depreciated line replacements are combined with voltage conversions or feeder capacity upgrade/additions. Overhead lines are replaced when alternatives such as maintenance or rehabilitation are not possible or cost effective. The consequences of not proceeding would be allowing the condition of these assets to deteriorate into a state negatively impacting public safety and/ or system reliability

PROJECT DETAIL/ SCOPE:

The scope of these projects included the rebuilding of the overhead distribution that was in poor condition and had reached the end of its life. The Town and Cobourg Public Utility Commission (presently LUI) made the assessment 25 years ago to convert the township from 4Kv to 27.6Kv. The project also facilitated the conversion from 4kv to 27.6kv as part of LUI's Asset Management strategy. Transformers, conductors, poles, guys/anchors, and other equipment were replaced if they were not recoverable.

EXPECTED BENEFITS:

- ✓ Reduced Exposure to safety hazards associated with aged plant and equipment
- ✓ Increased reliability of new plant and materials
- ✓ Increased safety of new design standards and clearances.
- ✓ Increased line capacity/lower line losses from voltage conversions

***PROJECT TITLE*:** Blake Street

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$5,000
1835	Overhead Conductors and Devices	$37,972
1850	Line Transformers	$5,098

PROJECT VALUE $ 48,070

***PROJECT TITLE*:** Burke Street
WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$15,000
1835	Overhead Conductors and Devices	$37,386
1850	Line Transformers	$5,359

PROJECT VALUE $ 57,746

***PROJECT TITLE*:** White Street
WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$80,000
1835	Overhead Conductors and Devices	$30,000
1850	Line Transformers	$10,000

PROJECT VALUE $ 120,000

***PROJECT TITLE*:** Burnham Street
WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$70,000
1850	Line Transformers	$15,000

PROJECT VALUE $ 85,000

***PROJECT TITLE*:** Havelock Street
WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$20,000
1835	Overhead Conductors and Devices	$18,421
1850	Line Transformers	$10,195

PROJECT VALUE $ 48,616

***PROJECT TITLE*:** Matthew Street
WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$32,000
1835	Overhead Conductors and Devices	$54,063
1850	Line Transformers	$15,293

PROJECT VALUE $ 101,356

***PROJECT TITLE*:** Victoria Street
WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$25,000
1835	Overhead Conductors and Devices	$27,265

PROJECT VALUE $ 52,265

***PROJECT TITLE*:** William Street
WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$25,000
1835	Overhead Conductors and Devices	$46,803
1850	Line Transformers	$8,120

PROJECT VALUE $ 79,923

***PROJECT TITLE*:** Kerr Street
WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$95,000
1835	Overhead Conductors and Devices	$124,990
1850	Line Transformers	$10,195

PROJECT VALUE $ 230,185

***PROJECT TITLE*:** Buchannan Street
WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$50,000
1835	Overhead Conductors and Devices	$56,838
1850	Line Transformers	$16,397

PROJECT VALUE $ 123,235

2011 UNDERGROUND REBUILD/UPGRADE CONVERSION PROJECTS

REBUILD/UPGRADE NEED:

LUI has a population of approximately 3,200 overhead line poles. LUI recognizes that the conditions of these assets deteriorate over time and LUI takes a proactive approach to their replacement. Asset Management Programs are in place to inspect all poles on a cyclical basis in all of LUI's service areas. Asset information is stored and analyzed with the help of LUI's Geographical Information System (GIS). Capital projects are prioritized using condition assessment data, asset age, reliability, supply and safety considerations, where possible depreciated line replacements are combined with voltage conversions or feeder capacity upgrade/additions. Overhead lines are replaced when alternatives such as maintenance or rehabilitation are not possible or cost effective**. In certain circumstances LUI finds it beneficial to replace the overheads lines with underground conductors and devices. Reasons include aesthetic appeal, zoning (subdivision and historical) regulations, and functionality of the lines.** The consequences of not proceeding would allow the condition of these assets to deteriorate into a state negatively impacting public safety and or system reliability.

PROJECT DETAIL/ SCOPE:

The scope of this project included the rebuilding of LUI's subdivisions and promoting the installation of **underground lines** for aesthetic appeal. The Town and Public Utility Commission made the assessment 25 years ago to convert the township from 4Kv to 27.6Kv. The project also facilitated the conversion from 4kv to 27.6 kv as part of LUI's Asset Management strategy. Transformers, conductors, poles, guys/anchors, and other equipment were replaced if they were not recoverable.

EXPECTED BENEFITS:

- ✓ Reduced Exposure to safety hazards associated with aged plant and equipment
- ✓ Increased reliability of new plant and materials
- ✓ Increased safety of new design standards and clearances.
- ✓ Increased line capacity/lower line losses from voltage conversions
- ✓ Increased Aesthetic Appeal

***PROJECT TITLE*:** Charles Street

PROJECT COSTSBY USOA:

USoA	Description	TOTAL VALUE
1840	Underground Conduit	$45,000
1835	Underground Conduit and Devices	$10,000
1850	Line Transformers	$15,000

PROJECT VALUE $ 70,000

2011 COMMERCIAL EXPANSION PROJECTS

COMMERCIAL EXPANSION NEED:

LUI's commercial additions are capital expansions to the LUI distribution system driven solely by customer demand. In accordance with the Distribution System Code, LUI performs economic evaluation for each project and provides the developer with an offer to connect. Developers that meet LUI's conditions of service and provide the necessary financial commitments are connected. Total expenditures vary with the level of economic activity in LUI's service area. The spending for this expansion project is customer driven.

There are no alternatives to proceeding with this customer requested work, and the consequence of not proceeding would result in LUI being in conflict with the Distribution System Code and municipal development objectives.

PROJECT DETAIL/ SCOPE:

This project involves the installation of a distribution transformer to facilitate electrical servicing of new commercial developments. Included are new primary cables, transformers, civil infrastructure, secondary cables, and other necessary plant and equipment. Work is coordinated with developers and other utilities and is completed in accordance with developer's timelines.

EXPECTED BENEFITS:

- ✓ Increased feeder capacity and distribution assets for growth.
- ✓ Expansion of system to connect new customers.

PROJECT TITLE: National Car Rental Ontario Street Commercial Service

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1835	Overhead Conductors and Devices	$2,878
1850	Line Transformers	$24,387

PROJECT VALUE $ 27,265

2011 DISTRIBUTION REBUILD/UPGRADE PROJECTS

DISTRIBUTION NEED:

LUI is supplied through the IESO controlled, Hydro One Transmission System at sub-transmission voltages below 50kV. LUI does not own a transformer station. LUI owns and operates 7 distribution stations five of which are in Cobourg's service area and two in Colborne's service area.

Expenditures in this category are made due to one of the following reasons;

- There is a need to increase capacity to meet growth in demand. Such needs are normally identified through system planning activities.
- The equipment requires replacement or a major refurbishment due to its condition. In such cases, regular maintenance will not address the problem nor is it cost effective. This is normally identified as a result of a variety of regularly schedules testing and maintenance activities.
- The equipment needs to be replaced due to obsolescence. Such needs are typically identified through the inability to source spare or replacement components.
- The equipment needs to be updated to meet regulatory requirement (Distribution System Code, Market Rules, etc.)

Where at all possible, projects are scheduled such that one project can satisfy other needs – including proactive measures for the future. Projects being captured in this category include new or major refurbishments to existing switches or breakers, transformers, switchgear, protection, and control systems, structural support systems, environmental protection systems. The implications of not taking proper actions and improving equipment capacity or condition as required could result in the inability to supply power to customers, damage to equipment, increased safety hazards to workers, unreliable or inoperative equipment, explosive equipment failure and breach of requirements set out in the Distribution System Code.

PROJECT DETAIL/ SCOPE:

LUI's aging electronic ABB protection relays used in its 27.6 kV distribution station was outdated by current technological standards and proving very difficult to maintain due to limited availability of replacement parts. LUI replaced the outdated ABB electronic relays with new modern Schweitzer Engineering Laboratories (S.E.L) relays with an improved protection setting scheme that has reduced the number of sustained outages. This project involved changing out the existing four ABB relays in the Brook Road North distribution station, programing the relays with their new settings, rewiring and modifying the switchgear's steel doors to accommodate the change in size of the relay chassis. The other project involved changing out the existing three ABB relays in the Victoria Street distribution station, programing the relays with their new settings, rewiring and modifying the switchgear's steel doors to accommodate the change in size of the relay chassis. Replacing the relays has enhanced the reliability of LUI's distribution system and added technology that LUI's plans to use in its proposed new SCADA system.

EXPECTED BENEFITS:

- ✓ Increased reliability of power to customers.
- ✓ Compliance with the Distribution System Code, HONI and/or IESO requirements.
- ✓ Increased Safety for LUI employees in operation.
- ✓ Proactive measures taken for future SCADA plans.
- ✓ Improved distribution protection scheme.

***PROJECT TITLE*:** Brook Road North Distribution Station

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1820	Distribution Station Equipment - normally Primary below 50 kV	$ 62,500

PROJECT VALUE $ 62,500

***PROJECT TITLE*:** Victoria Street Distribution Station

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1820	Distribution Station Equipment - normally Primary below 50 kV	$ 60,500

PROJECT VALUE $ 60,500

2011 DISTRIBUTION UPGRADE PROJECTS

LINE RECLOSER NEED:

LUI aims to provide its customers with a reliable supply of energy. LUI realizes that due to unforeseen circumstances lines are vulnerable to fault occurrences which are line interruptions caused by lightning strikes, swinging wires, high winds, or temporary contact with foreign objects. Transient faults can be cleared by momentarily de-energizing the line in order to allow the fault to clear. Auto reclosing of power lines has become a generally accepted practice within the electricity industry. Auto Reclosing provides significant advantages to LUI. Once installed at proper locations a majority of faults can be successfully cleared by the proper use of tripping and auto reclosing. This de-energizes the line long enough for the fault source to pass and the fault arc to de-energize, then automatically recloses the line to restore service. Thus, auto reclosing can significantly reduce the outage time due to faults and provide a higher level of service continuity to the customer.

PROJECT DETAIL/ SCOPE:

LUI identified which four points in the system would benefit from the auto-reclosing fixtures and installed them accordingly. LUI used its historical outage data to identify strategic locations within each feeder to reduce the number of customers affected by momentary and sustained outages. Outage times will be short compared to previously when personnel had to turn out and reenergize the lines after a fault for all customers in the area.

EXPECTED BENEFITS:

- ✓ Increased reliability of power to customers.
- ✓ Auto reclosing reduces operating costs.
- ✓ Outage times are restricted to one area of distribution.
- ✓ Outage times will be short in comparison as areas are isolated.

***PROJECT TITLE*: FOUR LINE RECLOSURES**

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1835	O/H Conductors & Devices	$100,000

PROJECT VALUE $ 100,000

2011 METERS UPGRADE PROJECTS

BUSINESS NEED:

In 2009 LUI was authorized by regulation to conduct Smart Metering activities. In 2008 LUI had already begun the RFP process to prepare for the 2009 approval. In 2009, meter activities were focused on the installation of new smart meters. LUI has incurred the costs of smart metering installation and stranded meter removal. Installation was performed over the course of three years and the most impacted of these years was in 2011 after the completion. Due to Smart Meter Activities LUI has incurred the capital cost of $255,550 – which is all related to smart meters and LUI is adding the cost to rate base in 2011. LUI is requesting approval for this addition in exhibit nine.

PROJECT DETAIL/ SCOPE:

As of the beginning of 2011 installation of smart meters in LUI's service area has been completed and has been activated for TOU billing. TOU billing began on June 1st, 2011. Smart Meters are beneficial as they will reduce overhead operating costs and they remotely communicate information back to the utility that is useful for identifying outages, electrical interferences, and up to date bill readings.

EXPECTED BENEFITS:

- ✓ Provides customers with greater control over their electricity usage.
- ✓ Accurate Bill readings, historical and current.
- ✓ Increased customer privacy due to auto relaying.
- ✓ Allows for faster outage detection and restoration of service.

***PROJECT TITLE*:** SMART & STRANDED METER UPGRADES

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1860	Meters	$6,000
1860	Smart Meters	$255,550

PROJECT VALUE $ 261,550

2011 GIS HANDHELDS ADDITIONS PROJECTS

GIS HANDHELDS BUSINESS NEED:

LUI requires handheld devices or tablet PC'S, which are GPS/Cellular enabled devices, to allow employees to take our GIS based data into the field while performing work orders and in the future LUI will be able to receive work orders to best record assets that are exchanged, repaired or moved.

GPS/Cellular enabled handhelds, will improve communication and efficiency of work done in the field and relates this information back to LUI's GIS database.

LUI intends to better track asset information by using the handhelds/tablets to locate all of its poles, wires, transformers, etc. while mapping the information using accurate X,Y co-ordinates as well as elevation associated with the items location.

PROJECT DETAIL/ SCOPE:

LUI identified the GPS/Cellular handheld units that best synchronize with LUI's current GIS system, and will upon approval, integrate them into our data collection process, allowing us to further build a reliable and accurate geographic information system asset database.

EXPECTED BENEFITS:

- ✓ Increased reliability of system information
- ✓ Better asset management tracking
- ✓ Increased asset communication
- ✓ Precise co-ordinates for asset location
- ✓ Creating accurate maps for planning purposes

PROJECT TITLE: GIS Handhelds

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1940	Tools & Equipment	$55,000

PROJECT VALUE $ 55,000

2011 EWART STREET EXPANSION PROJECTS

EXPANSION NEED:

LUI has a new customer who requested an expansion project to the current distribution network. In accordance with the Distribution System Code, LUI performs economic evaluation for each project and provides developer with an offer to connect. During the assessment and economic evaluation LUI found this project to be most economical if during this installation of the customer requested 27.6Kv the 44Kv line was also installed at the same time. The installation of the 44Kv line will improve reliability for all customers. Total expenditures vary with the level of economic activity in LUI's service area. The spending for this expansion project is customer driven.

There are no alternatives to proceeding with this customer requested work, and the consequence of not proceeding would result in LUI being in conflict with the Distribution System Code and municipal development objectives.

PROJECT DETAIL/ SCOPE:

This project involves the installation of line transformers to facilitate electrical servicing of new commercial developments. Included are new primary cables, transformers, civil infrastructure, secondary cables, and other necessary plant and equipment. Work is coordinated with developers and other utilities and is completed in accordance with developer's timelines. In this project LUI finds it beneficial to coordinate expansion with the developer of Ewart street expansion project to achieve its own development needs for the future in a cost effective manner.

EXPECTED BENEFITS:

- ✓ Increased feeder capacity and distribution assets for growth.
- ✓ Benefit of performing work consecutively to 27.6Kv and 44Kv
- ✓ Expansion of system to connect new customers.

***PROJECT TITLE*:** Ewart Street Expansion

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1850	Line Transformers	$10,000
1855	Services	$60,000

PROJECT VALUE $ 70,000

2012 Test Year Capital Additions

The 2012 Test Year Fixed Asset Continuity Schedule, Table 2-18 provides a summary of the additions and disposals based on the OEB USoA classification. This schedule may also be found in LUI's Revenue Requirement Model attached to this Application.

Table 2-18 2012 Test Year Fixed Asset Continuity Schedule

CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1610	Intangible Assets	0			0	0			0	0
N/A	1805	Land	219,284			219,284	0			0	219,284
CEC	1806	Land Rights	0			0	0			0	0
47	1808	Buildings and Fixtures	994,216	75,000		1,069,216	139,982	27,853		167,834	901,381
13	1810	Leasehold Improvements	0			0	0	-		0	0
47	1815	Transformer Station Equipment - Normally Prima	0			0	0	-		0	0
47	1820	Distribution Station Equipment - Normally Primary	3,562,235	600,000		4,162,235	1,733,771	94,586		1,828,357	2,333,878
47	1825	Storage Battery Equipment	0			0	0	-		0	0
47	1830	Poles, Towers and Fixtures	1,407,311	240,000		1,647,311	214,741	48,421		263,161	1,384,150
47	1835	Overhead Conductors and Devices	4,043,754	209,000		4,252,754	1,032,923	88,231		1,121,153	3,131,600
47	1840	Underground Conduit	1,078,943	160,000		1,238,943	213,943	32,693		246,636	992,308
47	1845	Underground Conductors and Devices	3,066,154			3,066,154	1,941,432	75,595		2,017,028	1,049,126
47	1850	Line Transformers	5,351,049	192,000		5,543,049	2,408,631	158,330		2,566,961	2,976,088
47	1855	Services	539,529	24,000		563,529	162,987	8,820		171,807	391,722
47	1860	Meters	225,726	20,000		245,726	157,638	8,418		166,056	79,670
47	1860	Smart Meters	1,822,179			1,822,179	243,758	112,744		356,502	1,465,677
N/A	1865	Other Installations on Customer's Premises	0			0	0	-		0	0
N/A	1905	Land	0			0	0	-		0	0
CEC	1906	Land Rights	0			0	0	-		0	0
47	1908	Buildings and Fixtures	0			0	0	-		0	0
13	1910	Leasehold Improvements	0			0	0	-		0	0
8	1915	Office Furniture and Equipment	82,026	25,000		107,026	14,286	9,453		23,739	83,287
10	1920	Computer Equipment - Hardware	81,199	150,000		231,199	23,945	29,551		53,496	177,703
12	1925	Computer Software	163,876	250,000		413,876	73,712	50,262		123,974	289,902
12	1925	Computer softward - Smart Meters	123,706			123,706	52,475	15,829		68,304	55,402
10	1930	Transportation Equipment	759,705			759,705	244,837	94,963		339,800	419,905
8	1935	Stores Equipment	0			0	0	-		0	0
8	1940	Tools, Shop and Garage Equipment	233,730	108,000		341,730	67,780	34,834		102,614	239,116
8	1945	Measurement and Testing Equipment	18,712			18,712	2,807	1,871		4,678	14,034
8	1950	Power Operated Equipment	0			0	0	-		0	0
8	1955	Communication Equipment	0			0	0	-		0	0
8	1960	Miscellaneous Equipment	0			0	0	-		0	0
47	1970	Load Management Controls - Customer Premises	0			0	0	-		0	0
47	1975	Load Management Controls - Utility Premises	0			0	0	-		0	0
47	1980	System Supervisory Equipment	0			0	0	-		0	0
47	1985	Sentinel Lighting Rentals	0			0	0	-		0	0
47	1990	Other Tangible Property	0			0	0	-		0	0
47	1995	Contributions and Grants	(2,257,659)	- 100,000		(2,357,659)	(439,742)	- 79,693		(519,435)	(1,838,225)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**21,515,673**	**1,953,000**	**0**	**23,468,673**	**8,289,904**	**812,762**	**0**	**9,102,666**	**14,366,008**
WIP		Work in Process	0			0	0			0	0
		Total after Work in Process	**21,515,673**	**1,953,000**	**0**	**23,468,673**	**8,289,904**	**812,762**	**0**	**9,102,666**	**14,366,008**

2012 Test Year Proposed Capital Projects

The following Table 2-20 provides LUI's capital additions by project, project type and USoA for the 2012 Test Year.

LUI 2012 SCHEDULED CAPITAL PROJECTS – MATERIALITY > $25,000

Table 2-19 2012 Test Year Proposed Capital Projects

2012 Forecast Capital Projects		1808	1820	1830	1835	1840	1845	1850	1855	1860	1915	1920	1925	1930	1940	1995	
	Type of Project	buildings	substations	Poles, Towers & Fixtures	O/H Cond & Devices	U/G Conduit	U/G Cond & Devices	Line Transformers	Services	Meters	Office Equipment	Computer Hardware	Computer Software	Transportation Equipment	Tools & Equipment	Contributions & Grants	Total
Burnham Street South	Rebuild / Upgrade			41,100	15,495			12,768									69,363
King St West	Rebuild / Upgrade			35,000	38,581			5,098									78,679
Monk Street	Rebuild / Upgrade			19,500	5,752												25,252
Sinclair Street South	Rebuild / Upgrade			7,000	3,030			4,896									14,926
Stuart Street	Rebuild / Upgrade			26,000	5,343			15,293									46,636
Tremaine Street	Rebuild / Upgrade			26,000	16,299			9,793									52,092
Burnham Street North	Rebuild / Upgrade			35,000	31,595			40,627									107,222
Ruth Street	Rebuild / Upgrade			5,000	10,826												15,826
Norma Street	Rebuild / Upgrade			4,000	10,826												14,826
Shirley Street	Rebuild / Upgrade			24,400	20,516			12,750									57,666
Elizabeth Street	Rebuild / Upgrade			4,500	24,263			17,910									46,673
Burnham Manor	Rebuild / Upgrade			4,500	10,335												14,835
Barbara Street	Rebuild / Upgrade			4,000	10,006			9,793									23,799
Tremaine Terrace	Rebuild / Upgrade			4,000	6,133												10,133
Liquor Store Expansion	Expansion							30,000									30,000
Albert Street Townhome Development	Expansion					80,000	80,000										160,000
No Frills Expansion	Expansion							30,000									30,000
Residential Upgrade Services	Upgrades								24,000								24,000
Boardroom	Expansion	50,000									12,500	10,000					72,500
Operational Work Center Expansion	Expansion	325,000									12,500	20,000					357,500
Demand meters replacement	Upgrades									50,000							50,000
Phone system	Purchase new											40,000					40,000
New financial software	Purchase new												325,000				325,000
SCADA System Implementation	Purchase new														286,000		286,000
Radio equipment (municipal initiative)	Municipal Initiative														97,000		97,000
Reel Trailer	Replacement														11,000		11,000
Existing hardware upgrades	Upgrades											80,000					80,000
Miscellaneous Other Projects	Rebuild / Upgrade							3,072									3,072
TRUCK														55,000			55,000
Contribution Grants																-100,000	-100,000
ACCOUNT TOTALS		375,000	0	240,000	209,000	80,000	80,000	192,000	24,000	50,000	25,000	150,000	325,000	55,000	394,000	-100,000	2,099,000

2012 OVERHEAD REBUILD/UPGRADE CONVERSION PROJECTS

REBUILD/UPGRADE NEED:

LUI has a population of approximately 3,200 overhead line poles. LUI recognizes that the conditions of these assets deteriorate over time and LUI takes a proactive approach to their replacement. Asset Management Programs are put in place to inspect all poles on a cyclical basis in all of LUI's service areas. Project areas are prioritized by the age of the assets to ensure proper safety precautions are taken to upgrade the assets that demand it. Asset information is stored and analyzed with the help of LUI's Geographical Information System (GIS). Capital projects are prioritized using condition assessment data, asset age, reliability, supply and safety considerations, where possible depreciated line replacements are combined with voltage conversions or feeder capacity upgrade/additions. Overhead lines are replaced when alternatives such as maintenance or rehabilitation are not possible or cost effective. The consequences of not proceeding would be allowing the condition of these assets to deteriorate into a state negatively impacting public safety and/ or system reliability

PROJECT DETAIL/ SCOPE:

The scope of these projects included the rebuilding of the overhead distribution that was in poor condition and had reached the end of its life. The Town and Cobourg Public Utility Commission (presently LUI) made the assessment 25 years ago to convert the township from 4Kv to 27.6Kv. The project also facilitated the conversion from 4kv to 27.6kv as part of LUI's Asset Management strategy. Transformers, conductors, poles, guys/anchors, and other equipment were replaced if they were not recoverable.

EXPECTED BENEFITS:

- ✓ Reduced Exposure to safety hazards associated with aged plant and equipment
- ✓ Increased reliability of new plant and materials
- ✓ Increased safety of new design standards and clearances.
- ✓ Increased line capacity/lower line losses from voltage conversions

***PROJECT TITLE*:** Burnham Street South

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$41,100
1835	Overhead Conductors and Devices	$15,495
1850	Line Transformers	$12,768

PROJECT VALUE $ 69,363

***PROJECT TITLE*:** King Street West
WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$35,000
1835	Overhead Conductors and Devices	$38,581
1850	Line Transformers	$5,098

PROJECT VALUE $ 78,679

***PROJECT TITLE*:** Monk Street
WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$19,500
1835	Overhead Conductors and Devices	$5,752

PROJECT VALUE $ 25,252

***PROJECT TITLE*:** Stuart Street
WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$26,000
1835	Overhead Conductors and Devices	$5,343
1850	Line Transformers	$15,293

PROJECT VALUE $ 46,636

***PROJECT TITLE*:** Tremaine Street
WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$26,000
1835	Overhead Conductors and Devices	$16,299
1850	Line Transformers	$9,793

PROJECT VALUE $ 52,092

***PROJECT TITLE*:** Burnham Street North
WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$35,000
1835	Overhead Conductors and Devices	$31,595
1850	Line Transformers	$40,267

PROJECT VALUE $ 107,222

***PROJECT TITLE*:** Shirley Street
WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$24,000
1835	Overhead Conductors and Devices	$20,516

1850	Line Transformers	$12,750

PROJECT VALUE $ 57,666

***PROJECT TITLE*:** Elizabeth Street

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1830	Poles, Towers and Fixtures	$4,500
1835	Overhead Conductors and Devices	$24,263
1850	Line Transformers	$17,910

PROJECT VALUE $ 46,673

2012 COMMERCIAL EXPANSION PROJECTS

COMMERCIAL EXPANSION NEED:

LUI's commercial additions are capital expansions to the LUI distribution system driven solely by customer demand. In accordance with the Distribution System Code, LUI performs economic evaluation for each project and provides the developer with an offer to connect. Developers that meet LUI's conditions of service and provide the necessary financial commitments are connected. Total expenditures vary with the level of economic activity in LUI's service area. The spending for this expansion project is customer driven.

There are no alternatives to proceeding with this customer requested work, and the consequence of not proceeding would result in LUI being in conflict with the Distribution System Code and municipal development objectives.

PROJECT DETAIL/ SCOPE:

This project involves the installation of line transformers to facilitate electrical servicing of new commercial developments. Included are new primary cables, transformers, civil infrastructure, secondary cables, and other necessary plant and equipment. Work is coordinated with developers and other utilities and is completed in accordance with developer's timelines.

EXPECTED BENEFITS:

- ✓ Increased feeder capacity and distribution assets for growth.
- ✓ Expansion of system to connect new customers.

***PROJECT TITLE*:** LCBO - Northumberland

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1850	Line Transformers	$30,000

PROJECT VALUE $ 30,000

***PROJECT TITLE*:** No Frills

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1850	Line Transformers	$30,000

PROJECT VALUE $ 30,000

2012 RESIDENTIAL EXPANSION PROJECTS

RESIDENTIAL EXPANSION NEED:

LUI's underground residential subdivisions are capital expansions to the LUI distribution system driven solely by customer demand. In accordance with the Distribution System Code, LUI performs economic evaluation for each project and provides developer with an offer to connect. Developers that meet LUI's conditions of service and provide the necessary financial commitments are connected. Total expenditures vary with the level of economic activity in LUI's service area. The spending for this expansion project is customer driven. In certain circumstances LUI is required to replace the overheads lines with **underground conductors** and device. Reasons include aesthetic appeal, zoning regulations, and functionality of the lines. There are no alternatives to proceeding with this customer requested work, and the consequence of not proceeding would result in LUI being in conflict with the Distribution System Code and municipal development objectives.

PROJECT DETAIL/ SCOPE:

The scope of this project included the rebuilding of LUI's subdivisions and promoting the installation of **underground lines** for aesthetic appeal. This project involves the installation of a substation to facilitate electrical servicing of new residential developments. Included are new primary cables, transformers, civil infrastructure, secondary cables, and other necessary plant and equipment. Work is coordinated with developers and other utilities and is completed in accordance with developer's timelines.

EXPECTED BENEFITS:

- ✓ Increased feeder capacity and distribution assets for growth.
- ✓ Expansion of system to connect new customers.

***PROJECT TITLE*:** Albert Street Townhome Development

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1840	Underground Conduit	$80,000
1845	Underground Conductors and Devices	$80,000

PROJECT VALUE $ 160,000

2012 BUSINESS CAPITAL EXPANSION PROJECTS

BOARDROOM EXPANSION NEED:

LUI developed an office improvement plan due to the aging capital in its office workplace. LUI has hired additional staff to the finance and billing department and this has resulted in lack of sufficient office space. LUI needs to renovate the building office space for additional room to accommodate these individuals. LUI's business required the expansion of its building therefore required proper workspace equipment and invested in the purchase of office furniture. For this capital project LUI also will require a new board room addition, as currently LUI's utility services operates with only one meeting room. The increased operations and initiatives for LUI's utility operation have created conflicting scheduling and inconvenience of only having one board room and LUI requires the addition to the building to operate more efficiently.

PROJECT DETAIL/ SCOPE:

LUI's scope for office renovations is to create more space for office, a new boardroom and provide proper equipment for the new employees. LUI has prioritized economically maximize its building space to satisfy this need. LUI will perform this project by analyzing the costs between various options. LUI is required to perform cost benefit analysis on the purchase of a new building, or to rather create additions to the existing building, and adjusting the current workspace. LUI's intention is to provide the best solution for adding a board room, and reconfiguring its office using a small renovation to add more office space. LUI intends relocate selected employees to the Operations Work Centre's office space to generate more office space and position employees in appropriate locations within their job description. LUI also sees potential in reclaiming a piece of its current building for additional capacity.

EXPECTED BENEFITS:

- ✓ Better performance from employees overall.
- ✓ Increased business meeting efficiency.
- ✓ Increased efficiency of work time capacity.
- ✓ Appropriate business standard board rooms.

***PROJECT TITLE*:** Board Room #2 Project

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1808	Buildings and Fixtures	$50,000
1915	Office Furniture and Equipment	$12,500
1920	Computer Equipment - Hardware	$20,000

PROJECT VALUE $ 72,500

2012 OPERATIONS CAPITAL EXPANSION PROJECTS

BUSINESS NEED:

LUI developed an office improvement plan to add more offices at the Ewart Street Operational Work Centre (OWC), for the purpose of facilitating daily required operations. The OWC currently holds LUI's fleet, inventory, and provides some office workspace which with increased initiatives is proving to be insufficient for required operations. LUI intends to relocate selected employees to the OWC office space to generate more office space in LUI's headquarters and situate employee's offices in appropriate locations within their job description. LUI also plans to hire staff for the purposes of complying with Smart Metering, and overlap transition time during a period in which LUI will experience a high volume of retirees in the outside department. LUI needs to renovate the OWC office space for additional room to accommodate these individuals. LUI's business demand requires the expansion of its building therefore requires proper workspace equipment, computer hardware and office furniture.

PROJECT DETAIL/ SCOPE:

LUI's scope for OWC Expansion is to create more space for offices as well as provide proper office equipment for the new employees. LUI is planning to economically maximize its OWC and extend the OWC to the south. LUI will perform this project by analyzing the costs between various options. LUI is required to perform cost benefit analysis on the purchase of a new building, or to rather create additions to the existing building, and adjusting the current workspace. LUI's intention is to provide the best solution for adding offices at the OWC, and reconfiguring its space by performing a renovation to add more work space for functional performance.

EXPECTED BENEFITS:

- ✓ Improve efficiencies
- ✓ Consolidate inventory to one secure location
- ✓ Store expensive line building equipment indoors
- ✓ Relocate new and existing operational staff
- ✓ Increased business operation efficiency
- ✓ Increased efficiency of work time capacity
- ✓ Appropriate business work space for field employees

***PROJECT TITLE*:** Operational Work Centre Expansion

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1808	Buildings and Fixtures	$325,000
1915	Office Furniture and Equipment	$12,500
1920	Computer Equipment - Hardware	$20,000

PROJECT VALUE $ 357,500

2012 PHONE SYSTEM EXPANSION PROJECTS

PHONE SYSTEM NEED:

LUI requires a new technologically advanced communication system to better operate its businesses daily functions. LUI recently affirmed that its current phone system is outdated and increasing in the irregular outage and idle periods during working days. LUI's business need is to have a reliable and flexible call system that hosts customers and vendors that LUI performs business with. As the business and regulatory environment progress more meetings can be held online via phone systems, which is an efficient and easy option of reducing travel expenses. LUI is required to report stats to the OEB based on performance standards and the current system is often difficult to pull accurate information. LUI receives many of its community informational calls via the communication system and realizes the importance placed on being connected 24/7 for emergency purposes. As the business community progresses LUIs business needs are more demanding about the methods in which it communicated outwards.

PROJECT DETAIL/ SCOPE:

LUI is evaluating the many available phone communications systems. LUI is also taking into consideration any available upgrades to its current system that can be performed to reduce the work time outages and any idle 'static' line-time. Phone capabilities required for proper utility operation is sophisticated call routing, call recording, call attachments, voicemail, call tracking, conferencing, automation, ability to service 40 plus simultaneous calls – including incoming, to make the entire staff more productive, and to broadcast voicemail to all staff. LUI will perform a cost benefit analysis of all options and ultimately chose the option with most benefits to its customers. The decision is heavily weighted on choosing a system that reduces risk to any parties well-being and safety due to emergency calls that must be responded to immediately.

EXPECTED BENEFITS:

- ✓ Functions as a traditional phone system or an IP telephone server.
- ✓ Supports both single locations and multi-site networks.
- ✓ Includes both basic call center and voice messaging capabilities.
- ✓ Scales up as business needs grow.

***PROJECT TITLE*:** Phone System

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1920	Computer Equipment - Hardware	$40,000

PROJECT VALUE $ 40,000

2012 TRANSPORTATION CAPITAL PROJECTS

BUSINESS TRANSPORTATION NEED:

LUI foresees the required investment of purchasing a new line truck for LUI's regular operations. This is due to the full depreciation of LUI's older vehicle which is anticipated to become high on maintenance. LUI requires this vehicle so that employees are better able to respond to calls in the field, and are capable to transport materials required for the job. These trucks are used in the utility industry as a means of performing necessary work around the service area. In complying with safety standards the depreciation of the company vehicles are 10 years and it is required that LUI update to the new design standards for Employee Safety criterions. LUI has determined that these time frames represent the most cost efficient schedules and that to extend beyond these timeframes LUI would incur increased maintenance costs reduced fleet reliability, and potential safety issues.

PROJECT DETAIL/ SCOPE:

The focus for the additional company truck capital addition in 2012 is to continue being within the safety standard code. Once a truck has fully depreciated an asset assessment evaluation is performed based on asset age, reliability, supply and safety considerations, where possible depreciated trucks are replaced to remain in date with the new model benefits.

EXPECTED BENEFITS:

- ✓ Reduced maintenance expense of older model.
- ✓ Increased safety of new design standards.
- ✓ Increased efficiency of work time capacity.

PROJECT TITLE: Line Truck Capital Fleet Addition

PROJECT COSTS BY USOA:

USoA	Description	TOTAL VALUE
1930	Transportation Equipment	$55,000

PROJECT VALUE $ 55,000

2012 HARDWARE CAPITAL EXPANSION PROJECTS

HARDWARE BUSINESS NEED:

LUI provides its employees with accessible hardware so that operations may continue at any time of day, as LUI strives to provide employees with flexible schedules, and mobility. LUI will require the updating and purchasing of printers, scanners, laptops, and a photocopier. The current billing printer is over 5 years old and by technological standards outdated. The new printer will be e-cabinet enabled. The purchases of laptops will be in correlation to new hires, and the expansion of our Operations Work Centre which will also require new server racks, cabinets and uninterrupted power supply. LUI also requires an upgrade to the corporate system servers in 2012 to be adaptable with software upgrades. The current finance server was purchased at the end of 2006 and upgrades in 2007, 2008. New finance hardware allows LUI to progressively remain current with both hardware technology solutions and finance software solutions – as discussed in software 2012 investments. Newer hardware also translates to lower operational annual maintenance fees and reduced risk of disrupted operations and idle work time.

PROJECT DETAIL/ SCOPE:

LUI's current software upgrade plans will require updated hardware platforms as well as more robust and powerful hardware to support their upgraded software applications. These corporate upgrades provide LUI with improved functionality. LUI will perform the necessary RFQ process and investigate the many options available for updating hardware; LUI will also focus on price point as a motivating factor to purchase. For LUI to continue operating efficiently these hardware additions are recognized as necessary and ultimately will benefit LUI's customer base.

EXPECTED BENEFITS:

- ✓ Increased business efficiency of the organization in providing up to date computer hardware.
- ✓ Current hardware allows the implementation of current software.
- ✓ Lower operational annual maintenance fees.
- ✓ Reduced risk of disrupted operations.

***PROJECT TITLE*:** Hardware Additions and Upgrades

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1920	Computer Equipment – Hardware	$80,000

PROJECT VALUE $ 80,000

2012 METERING SYSTEM UPGRADE AND REPAIR

DEMAND METER NEED:

LUI realizes that its older complex metering systems requires upgrading to correct accuracy issues, , billing issues, wiring issues, fusing issues and Measurement Canada compliance issues to remain within the current safety regulations. LUI aims to provide the best service possible to its customers and in doing so will require that these demand meters be upgraded and updated to repair all of the listed issues above.

PROJECT DETAIL/ SCOPE:

LUI intends to complete a program in 2012 to ensure that the metering systems in our "demand" class (50kW to 1000kW) are functioning accurately and safely with up to date technology. This program will focus on repairing and updating approximately 100 complex meters in the older metering systems including their current transformers and potential transformers and revenue electric meters.

EXPECTED BENEFITS:

- ✓ Increased safety for our meter reader.
- ✓ Updated departmental records of installation.
- ✓ Measurement Canada Compliant Metering Installations.
- ✓ Accurate Metering Installations.
- ✓ Move to Current Technology
- ✓ Validate Billing Multipliers

***PROJECT TITLE*:** DEMAND METER REPLACEMENT

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1860	Meters	$50,000

PROJECT VALUE $ 50,000

2012 SCADA SYSTEM DESIGN AND IMPLEMENTATION PROJECT

BUSINESS NEED:

Lakefront Utility Inc. does not presently have a SCADA system. A properly designed SCADA system will save time and money by eliminating the need for service personnel to visit each site for inspection, data collection/logging or make adjustments. Real-time monitoring, system modifications, troubleshooting, increased equipment life, automatic report generating and historic data analysis are some of the benefits of LUI's proposed SCADA system.

PROJECT DETAIL/ SCOPE:

LUI intends to design, install and implement a fully functional SCADA system including the required communications network in 2012. The SCADA system will be designed and installed in the distribution system so as to connect the two existing 27.6kV sub-stations, wholesale metering installations, distribution line reclosers, distribution automation equipment and the Operational Work Centre. Monitoring and operation of the SCADA system will be performed at the work center.

EXPECTED BENEFITS:

- ✓ Reduce operational costs
- ✓ Provide immediate knowledge of system performance
- ✓ Improve system efficiency and performance
- ✓ Increase equipment life
- ✓ Reduce costly repairs
- ✓ Reduce number of man-hours (labour costs) required for troubleshooting or service
- ✓ Free up personnel for other important tasks
- ✓ Facilitate compliance with regulatory agencies through automated report generating

***PROJECT TITLE*:** SCADA SYSTEM DESIGN AND IMPLEMENTATION

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1940	TOOLS & EQUIPMENT	$286,000

PROJECT VALUE $ 286,000

2012 SOFTWARE CAPITAL EXPANSION PROJECTS

FINANCIAL SOFTWARE NEED:

LUI requires an upgraded and more advanced finance system to better operate its businesses daily functions. LUI currently operates using a utility general ledger system that is unable to produce real time analysis or required financials such as monthly and quarterly. LUI realizes that its current finance system is outdated and takes time out of work day to analyze, and pull information, whereas there are better proven systems and automated methods to receive the exact results in a fraction of the time. Such outdated software over time results in higher operating expense due to inefficient use of time – such as data entry and data manipulation. LUI's business need is to have a reliable and flexible finance system that hosts abilities to analyze and audit its financials.

PROJECT DETAIL/ SCOPE:

The focus for the new purchase of a financial system in 2012 is to continue to build a proper database with user friendly multifunction purposes. A number of external tools will be implemented to aid in data transfer from the current system to tche new system. LUI places high value on its important core business functions by planning around financials and will chose the most appropriate system that offers all user functions to better comply with regulatory demands and budgeting commitments.

EXPECTED BENEFITS:

- ✓ Increased efficiency in maintaining information
- ✓ Increased efficiency in accessing information
- ✓ Increased ability to analyze data and develop real time financial strategies.
- ✓ Increased ability to report data
- ✓ Decreased data and finance collection time

***PROJECT TITLE*:** Financial Software

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1925	Computer Software	$325,000

PROJECT VALUE $ 325,000

2012 MUNICIPAL RADIO INITIATIVE PROJECTS

BUSINESS NEED:

Town of Cobourg uses an internal town system of all town departments including LUI but not shared with any other users outside of town. The system was installed in 1996 and has been assessed as at a fully depreciated state. Police and Fire have reported frequent failures of the system and the repair company reports that there is very limited support from Motorola any longer for this old system. The Police department report that one of four repeaters consistently fails, sometimes for several hours at a time. Cellular phones have recently become more prominent, radio communications remain critical for municipal department, especially public utility and safety departments. Radios are essential because of the law prohibiting cell phone usage while driving.

PROJECT DETAIL/ SCOPE:

LUI engaged in the reevaluation of the town radio system in 2010 when all town departments were directed to prepare an inventory of their radio hardware along with the requirements they needed to operate this emergency communication system. LUI participated in the final decision conference alongside other town departments and concluded the choice which best suited the needs of Cobourg was the Fleet Net system. Fleet Net System towers will provide coverage across Ontario. It is considered to be the most secure, robust and reliable public safety radio communications system currently available. This system will allow seamless integration with the other Town of Cobourg departments. The system has built in redundancy features to minimize failures and has a battery generator backup power. Currently all departments have approved Fleet Net Systems and commenced negotiations for the services, and integration in the Town of Cobourg to be finalized in 2012.

EXPECTED BENEFITS:

- ✓ Increased safety precautions of Utility infrastructure.
- ✓ Lower rate of failures and repair expenses.
- ✓ More secure and reliable public safety radio communications.
- ✓ Reduced risk of disrupted operations.

***PROJECT TITLE*:** Municipal Radio Equipment

WO COSTS BY USOA:

USoA	Description	TOTAL VALUE
1940	Tools, Shop and Garage Equipment	$97,000

PROJECT VALUE $ 97,000

ACCUMULATED DEPRECIATION

LUI uses the straight line method of amortization to determine the depreciation expense for all distribution assets on a pooled basis and identifiable assets individually. A full year's amortization is calculated on a straight line basis over estimated useful life of the asset. LUI uses the half year rule for calculating depreciation expense for the all years, including the 2012 Test Year. Details of LUI's depreciation by account number are provided in the Fixed Asset Continuity Schedules as set out above, by year, in the Rate Base section of this Exhibit.

Further information on LUI's depreciation expenses and continuity schedules are provided in Exhibit 4 – Operating Costs.

WORKING CAPITAL CALCULATION

Overview

LUI's working capital allowance is forecast to be $ 3,719,550 for the 2012 Test Year. LUI has not undertaken a Working Capital lead-lag study pending OEB direction and as such has calculated its working capital allowance using the 15% Allowance Approach as provided for at in the OEB's Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, dated June 22, 2011. LUI submits that its working capital calculations are not only consistent with the Filing Guidelines but are also consistent with OEB Decisions in distributors' cost of service applications approved in 2009, 2010 and 2011, where a utility specific lead-lag study had not been undertaken. The working capital allowance is based on LUI's proposed 2012 Test Year controllable expenses and cost of power. LUI has provided the calculations by the OEB's USoA classification for each of 2008 Actual to 2010 Actual, the 2011 Bridge Year and the 2012 Test Year in Table 2-20 below. The 2012 Test Year Cost of Power calculations are provided in Table 2-25 below.

The following Table 2-21 sets out LUI's year over year working capital variances for the 2008 OEB Approved, the three years 2008 to 2010 Actuals, 2011 Bridge Year and 2012 Test Year. Table 2-22 below is a reproduction of LUI's Summary of Working Capital Calculations. LUI notes

that the 2008 OEB Approved working capital was determined through the 2008 Cost of Service process.

MIFRS Conversion

Impact on OM&A

Conversion to Modified International Financial Reporting Standards (MIFRS)
International Accounting Standards 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 bring 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 expense and capital expenses, LUI analyzed all overhead items, to ensure there were no "overhead" costs being charged. LUI does not currently, nor previously allocate any general & administrative overhead to the cost of capital.
Therefore there is no direct impact on OM&A.

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 asset's useful lives, deprecation 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 IFRS (EB-2008-0408) the Board stated:
"While utilities remain solely responsible for complying with financial reporting requirements, the Board notes that generic depreciation study could assist 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 services life for their particular assets for financial reporting and regulatory requirements."

LUI 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 net depreciation (depreciation expense to the income statement) to be reduced in the 2012 Test Year.

In the Table 2-20 below, it can be noted that the impact of moving to IFRS has a direct impact to amortization of $ 427,567 . CGAAP amortization was at $ 1,243,776 and has been reduced to $ **816,209** . This has an obvious impact on LUI's Rate Base, specifically affecting our total OM&A, our net fixed assets, as well as our Revenue Deficiency.

Table 2-20 – Fixed Asset Continuity MIFRS

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2012

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1610	Intangible Assets	0			0	0			0	0
N/A	1805	Land	219,284			219,284	0			0	219,284
CEC	1806	Land Rights	0			0	0			0	0
47	1808	Buildings and Fixtures	994,216	375,000		1,369,216	139,982	26,446		166,428	1,202,788
13	1810	Leasehold Improvements	0			0	0	-		0	0
47	1815	Transformer Station Equipment - Normally Primar	0			0	0	-		0	0
47	1820	Distribution Station Equipment - Normally Primary	2,762,235			2,762,235	1,720,437	86,503		1,806,940	955,295
47	1825	Storage Battery Equipment	0			0	0	-		0	0
47	1830	Poles, Towers and Fixtures	1,557,311	240,000		1,797,311	217,741	76,093		293,833	1,503,478
47	1835	Overhead Conductors and Devices	4,213,754	209,000		4,422,754	1,036,323	284,135		1,320,457	3,102,296
47	1840	Underground Conduit	1,228,943	160,000		1,388,943	216,943	60,128		277,071	1,111,872
47	1845	Underground Conductors and Devices	3,066,154			3,066,154	1,941,432	121,478		2,062,910	1,003,244
47	1850	Line Transformers	5,351,049	192,000		5,543,049	2,408,631	216,252		2,624,882	2,918,167
47	1855	Services	599,529	24,000		623,529	164,187	25,775		189,963	433,566
47	1860	Meters	225,726	50,000		275,726	157,638	37,185		194,823	80,904
47	1860	Smart Meters	1,822,179			1,822,179	243,758	121,479		365,236	1,456,943
N/A	1865	Other Installations on Customer's Premises	0			0	0	-		0	0
N/A	1905	Land	0			0	0	-		0	0
CEC	1906	Land Rights	0			0	0	-		0	0
47	1908	Buildings and Fixtures	0			0	0	-		0	0
13	1910	Leasehold Improvements	0			0	0	-		0	0
8	1915	Office Furniture and Equipment	82,026	25,000		107,026	14,286	10,703		24,989	82,037
10	1920	Computer Equipment - Hardware	81,199	150,000		231,199	23,945	34,551		58,496	172,703
12	1925	Computer Software	163,876	325,000		488,876	73,712	64,878		138,589	350,286
12	1925	Computer softward - Smart Meters	123,706			123,706	52,475	24,741		77,216	46,490
10	1930	Transportation Equipment	759,705	55,000		814,705	244,837	98,401		343,237	471,467
8	1935	Stores Equipment	0			0	0	-		0	0
8	1940	Tools, Shop and Garage Equipment	233,730	394,000		627,730	67,780	45,490		113,269	514,460
8	1945	Measurement and Testing Equipment	18,712			18,712	2,807	1,871		4,678	14,034
8	1950	Power Operated Equipment	0			0	0	-		0	0
8	1955	Communication Equipment	0			0	0	-		0	0
8	1960	Miscellaneous Equipment	0			0	0	-		0	0
47	1970	Load Management Controls - Customer Premises	0			0	0	-		0	0
47	1975	Load Management Controls - Utility Premises	0			0	0	-		0	0
47	1980	System Supervisory Equipment	0			0	0	-		0	0
47	1985	Sentinel Lighting Rentals	0			0	0	-		0	0
47	1990	Other Tangible Property	0			0	0	-		0	0
47	1995	Contributions and Grants	(2,257,659)	- 100,000		(2,357,659)	(439,742)	- 81,693		(521,435)	(1,836,225)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**21,245,673**	**2,099,000**	**0**	**23,344,673**	**8,287,170**	**1,254,414**	**0**	**9,541,584**	**13,803,089**
WIP		Work in Process	0	100,000		100,000	0			0	100,000
		Total after Work in Process	**21,245,673**	**2,199,000**	**0**	**23,444,673**	**8,287,170**	**1,254,414**	**0**	**9,541,584**	**13,903,089**

Table 2-21 Summary of Working Capital

Summary of Working Capital

Description	2008 OEB Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Cost of Power	20,560,245	19,742,668	19,583,913	20,764,427	22,808,653	23,056,611
Operations	620,871	617,177	505,675	415,821	579,609	879,396
Maintenance	104,107	77,337	139,615	225,312	306,219	391,786
Billing & Collecting	428,844	440,285	407,715	425,479	501,542	500,298
Community Relations	19,767	8,053	(4,705)	13,355	13,927	14,345
Administration & General Expense	921,831	741,765	806,924	1,019,724	1,047,829	1,281,489
Property Taxes	55,209	42,890	53,482	46,698	48,099	49,542
Working Capital	22,710,874	21,670,175	21,492,619	22,910,816	25,305,878	26,173,467

Table 2-22 Working Capital Variances

Working Capital:

Description	2008 OEB Approved	2008 Actual	Variance from 2008 OEB Approved	2009 Actual	2009 Variance from 2008 Actual	2010 Actual	2010 Variance from 2009 Actual	2011 Bridge	2011 Variance from 2010 Actual	2012 Test	2012 Variance from 2011 Bridge
Cost of Power	20,560,245	19,742,668	(817,577)	19,583,913	(158,755)	20,764,427	1,180,514	22,808,653	2,044,226	23,056,611	247,957
Operations	620,871	617,177	(3,694)	505,675	(111,502)	415,821	(89,854)	579,609	163,788	879,396	299,787
Maintenance	104,107	77,337	(26,770)	139,615	62,278	225,312	85,697	306,219	80,907	391,786	85,567
Billing & Collecting	428,844	440,285	11,441	407,715	(32,570)	425,479	17,764	501,542	76,063	500,298	(1,244)
Community Relations	19,767	8,053	(11,714)	(4,705)	(12,758)	13,355	18,060	13,927	572	14,345	418
Administration & General Expense	921,831	741,765	(180,066)	806,924	65,158	1,019,724	212,800	1,047,829	28,105	1,281,489	233,660
Taxes Other Than Income Taxes	55,209	42,890	(12,319)	53,482	10,592	46,698	(6,784)	48,099	1,401	49,542	1,443
Working Capital	22,710,874	21,670,175	(1,040,699)	21,492,619	(177,557)	22,910,816	1,418,197	25,305,878	2,395,063	26,173,467	867,588

Table 2-23 Detailed Working Capital Calculations

Working Capital Allowance Calculation by Account

Description	2008 Actual	Allowance for Working Capital	2009 Actual	Allowance for Working Capital	2010 Actual	Allowance for Working Capital	2011 Bridge	Allowance for Working Capital	2012 Test	Allowance for Working Capital
Rate used for Working Capital Allowance		15%		15%		15%		15%		15%
Operation										
5005-Operation Supervision and Engineering	343,495	51,524	173,043	25,956	211,515	31,727	310,741	46,611	313,691	47,054
5010-Load Dispatching	0	0	0	0	0	0	0	0	0	0
5012-Station Buildings and Fixtures Expense	148,399	22,260	158,401	23,760	183,440	27,516	188,943	28,341	323,678	48,552
5014-Transformer Station Equipment - Operation Labour	0	0	0	0	0	0	0	0	0	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0	0	0	0	0	0	0	0	0	0
5016-Distribution Station Equipment - Operation Labour	0	0	0	0	0	0	0	0	0	0
5017-Distribution Station Equipment - Operation Supplies and Expenses	0	0	0	0	0	0	0	0	0	0
5020-Overhead Distribution Lines and Feeders - Operation Labour	1,314	197	5,211	782	1,043	157	2,523	378	2,599	390
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	63,084	9,463	21,690	3,254	4,151	623	29,642	4,446	35,331	5,300
5030-Overhead Sub transmission Feeders - Operation	223,159	33,474	153,369	23,005	160,832	24,125	178,880	26,832	309,975	46,496
5035-Overhead Distribution Transformers- Operation	133,540	20,031	107,960	16,194	26,977	4,047	122,488	18,373	126,163	18,924
5040-Underground Distribution Lines and Feeders - Operation Labour	0	0	0	0	0	0	0	0	0	0
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	2,449	367	0	0	0	0	0	0	631	95
5050-Underground Sub transmission Feeders - Operation	29,339	4,401	25,509	3,826	17,498	2,625	18,023	2,703	25,000	3,750
5055-Underground Distribution Transformers - Operation	15,286	2,293	25,314	3,797	17,456	2,618	19,352	2,903	19,933	2,990
5060-Street Lighting and Signal System Expense	0	0	0	0	0	0	0	0	0	0
5065-Meter Expense	0	0	0	0	0	0	0	0	0	0
5070-Customer Premises - Operation Labour	0	0	0	0	0	0	0	0	0	0
5075-Customer Premises - Materials and Expenses	0	0	0	0	0	0	15,202	2,280	31,316	4,697
5085-Miscellaneous Distribution Expense	0	0	300	45	0	0	0	0	0	0
5090-Underground Distribution Lines and Feeders - Rental Paid	0	0	0	0	0	0	0	0	77	12
5095-Overhead Distribution Lines and Feeders - Rental Paid	607	91	7,921	1,188	4,424	664	4,556	683	4,693	704
5096-Other Rent	0	0	0	0	0	0	0	0	0	0
Sub-Total	**960,672**	**144,101**	**678,718**	**101,808**	**627,336**	**94,100**	**890,350**	**133,552**	**1,193,087**	**178,963**
Maintenance										
5105-Maintenance Supervision and Engineering	0	0	0	0	0	0	0	0	0	0
5110-Maintenance of Buildings and Fixtures - Distribution Stations	0	0	0	0	0	0	0	0	0	0
5112-Maintenance of Transformer Station Equipment	0	0	0	0	0	0	34,875	5,231	52,313	7,847
5114-Maintenance of Distribution Station Equipment	0	0	0	0	0	0	0	0	0	0
5120-Maintenance of Poles, Towers and Fixtures	0	0	0	0	0	0	0	0	0	0
5125-Maintenance of Overhead Conductors and Devices	0	0	0	0	0	0	0	0	0	0
5130-Maintenance of Overhead Services	3,033	455	8,375	1,256	36,678	5,502	40,570	6,085	41,787	6,268
5135-Overhead Distribution Lines and Feeders - Right of Way	0	0	0	0	0	0	0	0	10,000	1,500
5145-Maintenance of Underground Conduit	0	0	0	0	0	0	0	0	3,000	450
5150-Maintenance of Underground Conductors and Devices	0	0	0	0	0	0	0	0	0	0
5155-Maintenance of Underground Services	0	0	0	0	0	0	0	0	0	0
5160-Maintenance of Line Transformers	0	0	0	0	0	0	0	0	0	0
5165-Maintenance of Street Lighting and Signal Systems	1,197	180	9,015	1,352	8,699	1,305	8,960	1,344	9,229	1,384
5170-Sentinel Lights - Labour	35,904	5,386	42,096	6,314	30,881	4,632	35,674	5,351	36,139	5,421
5172-Sentinel Lights - Materials and Expenses	0	0	0	0	0	0	0	0	0	0
5175-Maintenance of Meters	0	0	0	0	0	0	0	0	0	0
5178-Customer Installations Expenses- Leased Property	0	0	0	0	0	0	0	0	0	0
5195-Maintenance of Other Installations on Customer Premises	0	0	0	0	0	0	0	0	0	0
Sub-Total	**40,134**	**6,020**	**59,486**	**8,923**	**76,259**	**11,439**	**120,079**	**18,012**	**152,467**	**22,870**
Billing and Collections										
5305-Supervision	0	0	0	0	0	0	0	0	0	0
5310-Meter Reading Expense	0	0	0	0	0	0	0	0	0	0
5315-Customer Billing	0	0	0	0	0	0	0	0	0	0
5320-Collecting	64,970	9,746	63,778	9,567	62,890	9,433	134,191	20,129	17,192	2,579
5325-Collecting- Cash Over and Short	122,411	18,362	129,841	19,476	126,867	19,030	130,575	19,586	131,000	19,650
5330-Collection Charges	97,641	14,646	92,675	13,901	103,730	15,560	106,842	16,026	130,277	19,542
5335-Bad Debt Expense	5	1	128	19	(17)	(3)	0	0	0	0
5340-Miscellaneous Customer Accounts Expenses	4,440	666	8,925	1,339	4,067	610	4,050	608	4,172	626
Sub-Total	**289,467**	**43,420**	**295,347**	**44,302**	**297,537**	**44,631**	**375,659**	**56,349**	**282,641**	**42,396**

Description	2008 Actual	Allowance for Working Capital	2009 Actual	Allowance for Working Capital	2010 Actual	Allowance for Working Capital	2011 Bridge	Allowance for Working Capital	2012 Test	Allowance for Working Capital
Rate used for Working Capital Allowance		15%		15%		15%		15%		15%
Community Relations										
5405-Supervision	121,125	18,169	99,078	14,862	105,261	15,789	103,995	15,599	195,112	29,267
5410-Community Relations - Sundry	0	0	0	0	0	0	0	0	0	0
5415-Energy Conservation	0	0	0	0	0	0	0	0	0	0
5420-Community Safety Program	8,053	1,208	(4,705)	(706)	13,355	2,003	13,927	2,089	14,345	2,152
5425-Miscellaneous Customer Service and Informational Expenses	0	0	0	0	0	0	0	0	0	0
5505-Supervision	0	0	0	0	0	0	0	0	0	0
5510-Demonstrating and Selling Expense	0	0	0	0	0	0	0	0	0	0
5515-Advertising Expense	0	0	0	0	0	0	0	0	0	0
5520-Miscellaneous Sales Expense	0	0	0	0	0	0	0	0	0	0
Sub-Total	**129,178**	**19,377**	**94,373**	**14,156**	**118,615**	**17,792**	**117,922**	**17,688**	**209,457**	**31,419**
Administrative and General Expenses										
5605-Executive Salaries and Expenses	0	0	0	0	0	0	0	0	0	0
5610-Management Salaries and Expenses	0	0	0	0	0	0	0	0	0	0
5615-General Administrative Salaries and Expenses	16,612	2,492	33,310	4,996	46,510	6,977	47,906	7,186	49,343	7,401
5620-Office Supplies and Expenses	336,516	50,477	365,367	54,805	426,686	64,003	449,700	67,455	494,916	74,237
5625-Administrative Expense Transferred Credit	86,694	13,004	77,739	11,661	91,247	13,687	93,985	14,098	143,854	21,578
5630-Outside Services Employed	77,736	11,660	95,090	14,264	99,808	14,971	102,802	15,420	105,886	15,883
5635-Property Insurance	0	0	0	0	0	0	0	0	0	0
5640-Injuries and Damages	7,309	1,096	62,428	9,364	70,228	10,534	101,364	15,205	155,405	23,311
5645-Employee Pensions and Benefits	20,347	3,052	24,675	3,701	27,066	4,060	27,878	4,182	28,715	4,307
5650-Franchise Requirements	48,141	7,221	48,045	7,207	58,794	8,819	60,558	9,084	62,375	9,356
5655-Regulatory Expenses	0	0	0	0	0	0	0	0	0	0
5660-General Advertising Expenses	0	0	0	0	0	0	0	0	0	0
5665-Miscellaneous General Expenses	85,631	12,845	33,127	4,969	58,782	8,817	85,546	12,832	103,562	15,534
5670-Rent	2,050	308	3,486	523	2,213	332	2,583	387	4,660	699
5675-Maintenance of General Plant	2,450	368	40	6	0	0	830	125	855	128
5680-Electrical Safety Authority Fees	0	0	0	0	0	0	0	0	0	0
5685-Independent Market Operator Fees and Penalties	28,575	4,286	44,930	6,740	32,398	4,860	33,370	5,005	84,371	12,656
5695-OM&A Contra Account	29,704	4,456	40,600	6,090	53,616	8,042	41,306	6,196	47,546	7,132
Sub-Total	**741,765**	**111,265**	**828,837**	**124,325**	**967,349**	**145,102**	**1,047,829**	**157,174**	**1,281,489**	**192,223**

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Property Taxes										
6105 - Property Taxes	0	0	0	0	0	0	0	0	0	0
Sub-Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Cost of Power										
4705-Power Purchased	0	0	0	0	0	0	0	0	0	0
4708-Charges-WMS	0	0	0	0	0	0	0	0	0	0
4710-Cost of Power Adjustments	15,673,853	2,351,078	15,841,024	2,376,154	16,827,239	2,524,086	18,452,714	2,767,907	18,601,618	2,790,243
4712-Charges-One-Time	1,605,486	240,823	1,599,200	239,880	1,448,652	217,298	1,704,674	255,701	1,718,234	257,735
4714-Charges-NW	0	0	0	0	0	0	0	0	0	0
4716-Charges-CN	1,119,497	167,925	1,023,656	153,548	1,244,308	186,646	1,309,278	196,392	1,358,005	203,701
4730-Rural Rate Assistance	0	0	0	0	0	0	0	0	0	0
4750-LV Charges	0	0	0	0	0	0	0	0	0	0
Sub-Total	**18,398,836**	**2,759,825**	**18,463,880**	**2,769,582**	**19,520,198**	**2,928,030**	**21,466,667**	**3,220,000**	**21,677,857**	**3,251,679**
WORKING CAPITAL ALLOWANCE TOTAL	**20,560,052**	**3,084,008**	**20,420,641**	**3,063,096**	**21,607,295**	**3,241,094**	**24,018,506**	**3,602,776**	**24,796,999**	**3,719,550**

COST OF POWER

LUI has calculated cost of power for the 2011 Bridge year and 2012 Test Year based on the results of the load forecast which is discussed in detail in Exhibit 3 below. The electricity prices used in the calculation were the published prices in the OEB's Regulated Price Plan Price Report – May 1, 2011 to April 30, 2012, issued April 15, 2011. LUI 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 2011 Bridge Year and a cost of power summary are provided in the following Table 2-23 and Table 2-24 respectively. The cost of power calculations for the 2012 Test Year and a cost of power summary are provided in the following Table 2-25 and Table 2-26 respectively.

Table 2-24 2011 Bridge Year Cost of Power Forecast Calculation

2011 Load Foreacst	**kWh**	**kW**	**2010 %RPP**
Residential	72,459,122		88%
General Service < 50 kW	34,436,304		88%
General Service 50 to 2,999 kW	120,035,230	301,159	11%
Intermediate 3,000 to 4,999 kW	19,295,356	47,442	
Street Lighting	1,204,881	3,307	
Sentinel Lighting	78,652	218.4773	0%
Unmetered Scattered Load	716,623		0%
TOTAL	**248,226,168**	**352,126**	

Electricity - Commodity RPP	**2011**	**2011 Loss**			
Class per Load Forecast RPP	**Forecasted**	**Factor**	**2011**		
Residential	64,094,287	1.0565	67,717,330	$0.07298	$4,942,011
General Service < 50 kW	30,352,279	1.0565	32,067,995	$0.07298	$2,340,322
General Service 50 to 2,999 kW	12,758,670	1.0565	13,479,876	$0.07298	$983,761
Intermediate 3,000 to 4,999 kW	0	1.0565	0	$0.07298	$0
Street Lighting	0	1.0565	0	$0.07298	$0
Sentinel Lighting	1	1.0565	1	$0.07298	$0
Unmetered Scattered Load	2,049	1.0565	2,165	$0.07298	$158
TOTAL	**107,207,286**		**113,267,368**		**$8,266,253**

Electricity - Commodity Non-RPP	**2011**	**2011 Loss**			
Class per Load Forecast	**Forecasted**	**Factor**	**2011**		
Residential	8,364,835	1.0565	8,837,673	$0.06837	$604,232
General Service < 50 kW	4,084,025	1.0565	4,314,882	$0.06837	$295,008
General Service 50 to 2,999 kW	107,276,561	1.0565	113,340,558	$0.06837	$7,749,094
Intermediate 3,000 to 4,999 kW	19,295,356	1.0565	20,386,060	$0.06837	$1,393,795
Street Lighting	1,204,881	1.0565	1,272,989	$0.06837	$87,034
Sentinel Lighting	78,651	1.0565	83,097	$0.06837	$5,681
Unmetered Scattered Load	714,574	1.0565	754,966	$0.06837	$51,617
TOTAL	**141,018,882**		**148,990,223**		**$10,186,462**

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**	**2011**		
Residential		kWh	76,555,002	$0.0054	$413,397
General Service < 50 kW		kWh	36,382,877	$0.0049	$178,276
General Service 50 to 2,999 kW		kW	301,159	$1.9987	$601,926
Intermediate 3,000 to 4,999 kW		kW	47,442	$2.2353	$106,048
Street Lighting		kW	3,307	$1.5074	$4,985
Sentinel Lighting		kW	218	$1.5148	$331
Unmetered Scattered Load		kWh	757,131	$0.0057	$4,316
TOTAL					**$1,309,278**

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**	**2011**		
Residential		kWh	76,555,002	$0.0043	$329,187
General Service < 50 kW		kWh	36,382,877	$0.0039	$141,893
General Service 50 to 2,999 kW		kW	301,159	$1.5466	$465,772
Intermediate 3,000 to 4,999 kW		kW	47,442	$1.8241	$86,540
Street Lighting		kW	3,307	$1.1956	$3,954
Sentinel Lighting		kW	218	$1.2205	$267
Unmetered Scattered Load		kWh	757,131	$0.0048	$3,634
TOTAL					**$1,031,246**

Wholesale Market Service					
Class per Load Forecast			**2011**		
Residential			76,555,002	$0.0052	$398,086
General Service < 50 kW			36,382,877	$0.0052	$189,191
General Service 50 to 2,999 kW			126,820,434	$0.0052	$659,466
Intermediate 3,000 to 4,999 kW			20,386,060	$0.0052	$106,008
Street Lighting			1,272,989	$0.0052	$6,620
Sentinel Lighting			83,098	$0.0052	$432
Unmetered Scattered Load			757,131	$0.0052	$3,937
TOTAL			**262,257,591**		**$1,363,739**

Rural Rate Assistance					
Class per Load Forecast			**2011**		
Residential			76,555,002	$0.0013	$99,522
General Service < 50 kW			36,382,877	$0.0013	$47,298
General Service 50 to 2,999 kW			126,820,434	$0.0013	$164,867
Intermediate 3,000 to 4,999 kW			20,386,060	$0.0013	$26,502
Street Lighting			1,272,989	$0.0013	$1,655
Sentinel Lighting			83,098	$0.0013	$108
Unmetered Scattered Load			757,131	$0.0013	$984
TOTAL			**262,257,591**		**$340,935**

Low Voltage		**Volume**			
Class per Load Forecast		**Metric**	**2011**		
Residential		kWh	72,459,122	$0.0013	$94,197
General Service < 50 kW		kWh	34,436,304	$0.0012	$41,324
General Service 50 to 2,999 kW		kW	301,159	$0.4864	$146,484
Intermediate 3,000 to 4,999 kW		kW	47,442	$0.5570	$26,425
Street Lighting		kW	3,307	$0.3708	$1,226
Sentinel Lighting		kW	218	$0.3754	$82
Unmetered Scattered Load		kWh	716,623	$0.0014	$1,003
TOTAL					**$310,741**

Table 2-25 2011 Bridge Year Cost of Power Summary

	2011
4705-Power Purchased	$18,452,714
4708-Charges-WMS	$1,363,739
4714-Charges-NW	$1,309,278
4716-Charges-CN	$1,031,246
4730-Rural Rate Assistance	$340,935
4750-Low Voltage	$310,741
TOTAL	**22,808,653**

Table 2-26 2012 Test Year Cost of Power Forecast Calculation

2012 Load Foreacst	**kWh**	**kW**	**2010 %RPP**
Residential	73,125,152		88%
General Service < 50 kW	35,160,634		88%
General Service 50 to 2,999 kW	120,608,902	303,629	11%
Intermediate 3,000 to 4,999 kW	19,295,356	47,442	0%
Street Lighting	1,215,575	3,343	0%
Sentinel Lighting	78,431	217.8652	0%
Unmetered Scattered Load	716,623		0%
TOTAL	**250,200,674**	**354,633**	

Electricity - Commodity RPP	**2012**	**2012 Loss**			
Class per Load Forecast RPP	**Forecasted**	**Factor**	**2012**		
Residential	64,683,429	1.0565	68,339,774	$0.07298	$4,987,437
General Service < 50 kW	30,990,706	1.0565	32,742,511	$0.07298	$2,389,548
General Service 50 to 2,999 kW	12,819,646	1.0565	13,544,299	$0.07298	$988,463
Intermediate 3,000 to 4,999 kW	0	1.0565	0	$0.07298	$0
Street Lighting	0	1.0565	0	$0.07298	$0
Sentinel Lighting	1	1.0565	1	$0.07298	$0
Unmetered Scattered Load	2,049	1.0565	2,165	$0.07298	$158
TOTAL	**108,495,831**		**114,628,750**		**$8,365,606**

Electricity - Commodity Non-RPP	**2012**	**2012 Loss**			
Class per Load Forecast	**Forecasted**	**Factor**	**2012**		
Residential	8,441,723	1.0565	8,918,907	$0.06837	$609,786
General Service < 50 kW	4,169,928	1.0565	4,405,641	$0.06837	$301,214
General Service 50 to 2,999 kW	107,789,256	1.0565	113,882,234	$0.06837	$7,786,128
Intermediate 3,000 to 4,999 kW	19,295,356	1.0565	20,386,060	$0.06837	$1,393,795
Street Lighting	1,215,575	1.0565	1,284,288	$0.06837	$87,807
Sentinel Lighting	78,430	1.0565	82,864	$0.06837	$5,665
Unmetered Scattered Load	714,574	1.0565	754,966	$0.06837	$51,617
TOTAL	**141,704,842**		**149,714,959**		**$10,236,012**

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**	**2012**		
Residential		kWh	77,258,681	$0.0055	$428,618
General Service < 50 kW		kWh	37,148,151	$0.0050	$187,009
General Service 50 to 2,999 kW		kW	303,629	$2.0534	$623,477
Intermediate 3,000 to 4,999 kW		kW	47,442	$2.2965	$108,951
Street Lighting		kW	3,343	$1.5487	$5,178
Sentinel Lighting		kW	218	$1.5563	$339
Unmetered Scattered Load		kWh	757,131	$0.0059	$4,434
TOTAL					**$1,358,005**

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**	**2012**		
Residential		kWh	77,258,681	$0.0044	$339,852
General Service < 50 kW		kWh	37,148,151	$0.0040	$148,210
General Service 50 to 2,999 kW		kW	303,629	$1.5822	$480,392
Intermediate 3,000 to 4,999 kW		kW	47,442	$1.8660	$88,530
Street Lighting		kW	3,343	$1.2231	$4,089
Sentinel Lighting		kW	218	$1.2486	$272
Unmetered Scattered Load		kWh	757,131	$0.0049	$3,718
TOTAL					**$1,065,063**

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Wholesale Market Service					
Class per Load Forecast				**2012**	
Residential			77,258,681	$0.0052	$401,745
General Service < 50 kW			37,148,151	$0.0052	$193,170
General Service 50 to 2,999 kW			127,426,534	$0.0052	$662,618
Intermediate 3,000 to 4,999 kW			20,386,060	$0.0052	$106,008
Street Lighting			1,284,288	$0.0052	$6,678
Sentinel Lighting			82,865	$0.0052	$431
Unmetered Scattered Load			757,131	$0.0052	$3,937
TOTAL			**264,343,709**		**$1,374,587**

Rural Rate Assistance					
Class per Load Forecast				**2012**	
Residential			77,258,681	$0.0013	$100,436
General Service < 50 kW			37,148,151	$0.0013	$48,293
General Service 50 to 2,999 kW			127,426,534	$0.0013	$165,654
Intermediate 3,000 to 4,999 kW			20,386,060	$0.0013	$26,502
Street Lighting			1,284,288	$0.0013	$1,670
Sentinel Lighting			82,865	$0.0013	$108
Unmetered Scattered Load			757,131	$0.0013	$984
TOTAL			**264,343,709**		**$343,647**

Low Voltage					
Class per Load Forecast				**2012**	
Residential			73,125,152	$0.0013	$95,063
General Service < 50 kW			35,160,634	$0.0012	$42,193
General Service 50 to 2,999 kW			303,629	$0.4864	$147,685
Intermediate 3,000 to 4,999 kW			47,442	$0.5570	$26,425
Street Lighting			3,343	$0.3708	$1,240
Sentinel Lighting			218	$0.3754	$82
Unmetered Scattered Load			716,623	$0.0014	$1,003
TOTAL					**$313,691**

Table 2-27 2012 Test Year Cost of Power Summary

	2012
4705-Power Purchased	$18,601,618
4708-Charges-WMS	$1,374,587
4714-Charges-NW	$1,358,005
4716-Charges-CN	$1,065,063
4730-Rural Rate Assistance	$343,647
4750-Low Voltage	$313,691
TOTAL	**23,056,611**

Service Quality and Reliability

LUI monitors and relies on its service quality and reliability indices (SQIs) monthly as a means of measuring system performance. LUI's commitment to stakeholders is to ensure "highest

standards of performance and business excellence for the safe, reliable provision of service". An SQI report, comparing the annual monthly results of SAIDI, SAIFI and CAIDI and the 5 year average, is prepared for trending purposes in the following chart.

The charts below provide LUI's reliability performance for each of the measures over the period 2006-2010. Year over year fluctuations may result from variations in weather such as extreme lightning, excessive snowfalls, ice storms, foreign interference such as animal contacts and motor vehicle accidents. LUI's system performance indices are trending positively showing an overall improvement in reliability. A personnel change responsible for reporting reliability indices in 2010 improperly included loss of supply data in the calculations. The tables below show what was reported to the OEB and have not been modified to show the more accurate values. Trending for 2011 is more inline with previous years showing a continued improvement to the system reliability.

Table 2-28 System Average Outage Frequency Performance

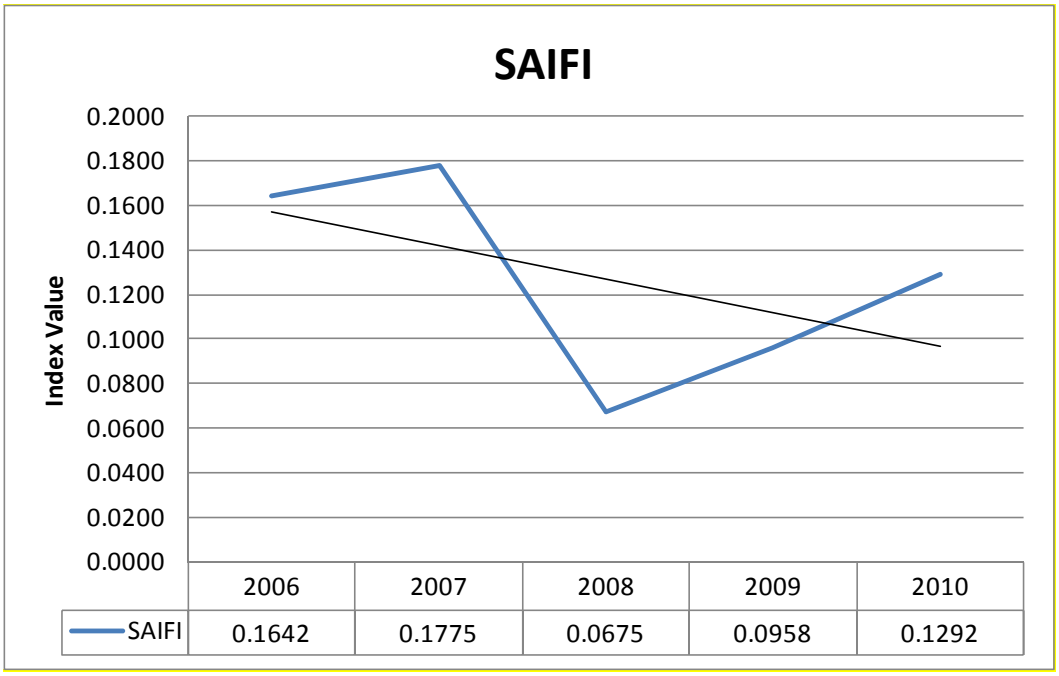


Table 2-29 System Average Duration Performance

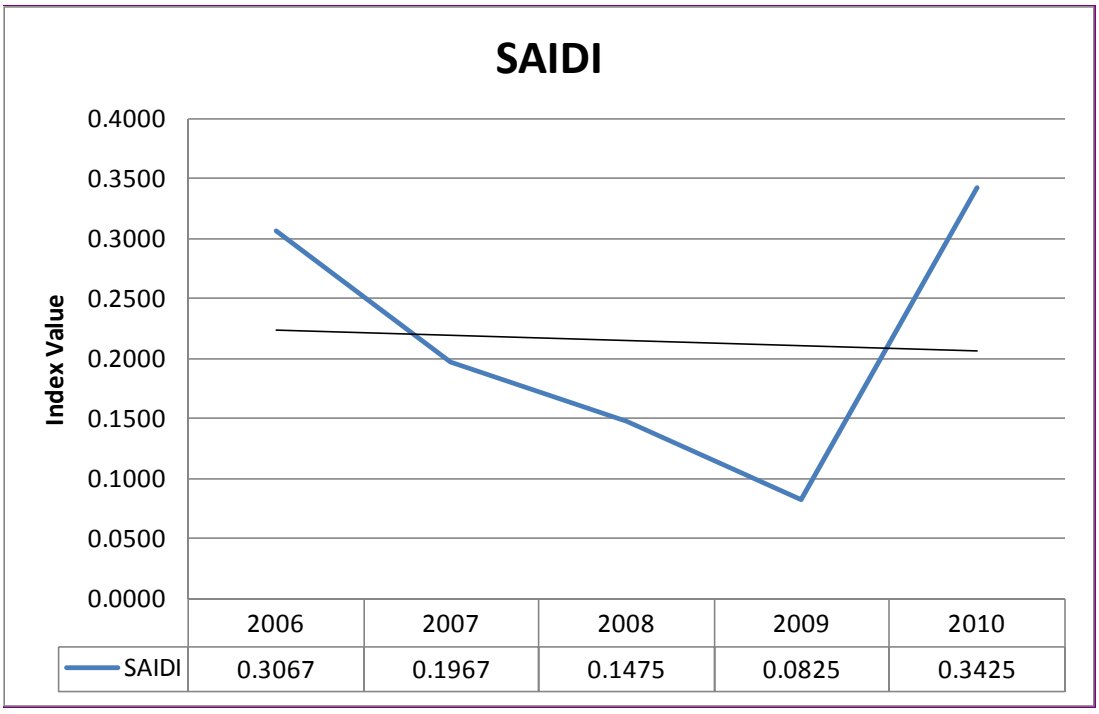
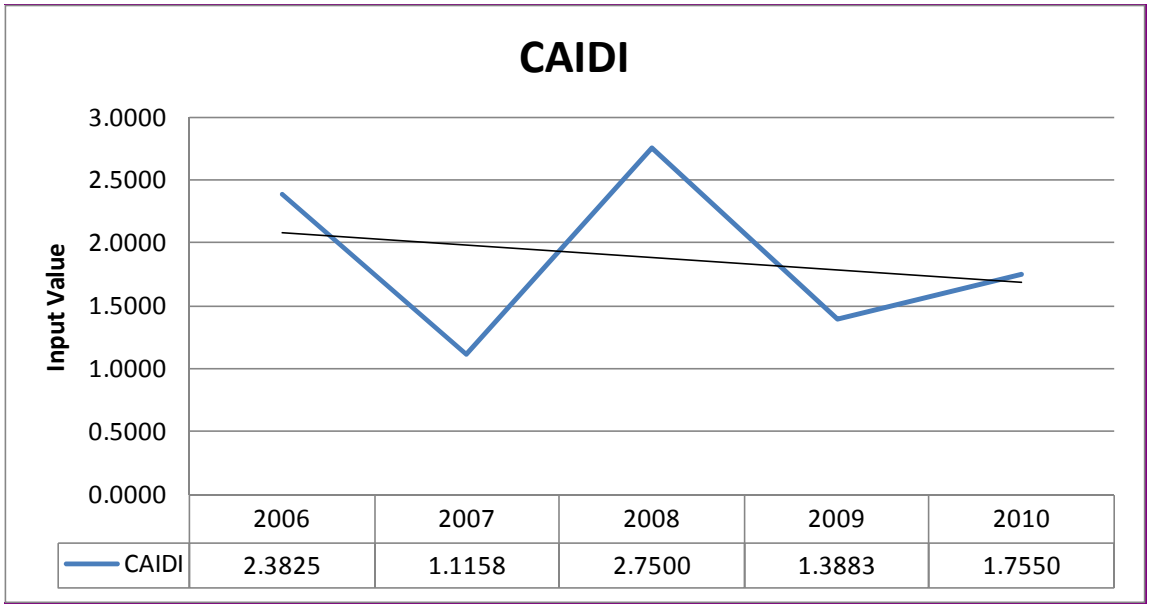


Table 2-30 Average Customer Restoration Time



SUMMARY

LUI has provided explanations to address its actual capital investments for year 2008 to 2010 and provided details in support of its 2011 Bridge Year and 2012 Test Year capital and working capital requirements as required in the Filing Requirements.

GREEN ENERGY ACT PLAN CAPITAL EXPENDITURES

In accordance with the filing requirements dated June 22, 2011, LUI has prepared and submitted to the OPA, a Green Energy Plan, dated May 16, 2011 for review (Appendix B to this Exhibit) . The OPA has reviewed the Basic Green Energy Plan submitted by LUI and in Appendix A below, is attached the comments received by the OPA.

APPENDIX A – COMMENTS ON GREEN ENERGY PLAN

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.

Lakefront Utility Services Inc. Basic Green Energy Act Plan

On July 11, 2011, the OPA received a Basic GEA Plan from Lakefront Utility Services Inc. ("LUI"). The OPA has reviewed LUI's Plan and has provided its comments below.

OPA FIT/microFIT Applications Received

LUI's Plan identifies 3,480 kW of FIT applications and 226 kW of microFIT applications received. These have been itemized by capacity and feeder in the Plan on page 6.

To date, the OPA has received 13 capacity allocation exempt ("CAE") FIT applications, 1 capacity allocation required ("CAR") FIT applications, totalling 4,7654 kW of FIT applications in LUI's area. Among these 14 FIT applications, 4 CAE projects, representing 1,286 kW of capacity, have received FIT contracts and the rest are still under review by the OPA.

The OPA also notes that 36 microFIT applications are in LUI's distribution area for a total of 279 kW. At this time, 9 microFIT applications have been connected, 7 microFIT applications have been terminated, and another 7 microFIT applications are waiting for conditional offers (leaving a total of 101 kW of microFIT applications to be connected).

Upstream Transmission Constraints

LUI's Plan identifies that Port Hope TS DESN1 has reached its total connectable capacity, leaving no additional capacity for any new renewable generation connections in Colborne. The OPA's information on system capability confirms this finding. LUI's GEA Plan notes that upgrades to Hydro One's system are required at Port Hope TS DESN1 before additional distribution level investment to enable renewable generation can be made. The OPA agrees with this statement.

LUI's Plan also notes that currently 10 MW of FIT applications have applied at Port Hope TS DESN2, leaving 57.2 MW of thermal capacity at this station. According to OPA's information, there are currently 11 MW of FIT applications at Port Hope TS DESN2 and 56 MW of capacity is remaining at this station.

Finally, LUI's Plan notes its expectation that larger FIT applications will typically displace customer load and are not expected to be net exporters of energy to the distribution system. While this may lessen impacts on the distribution system, the OPA would like to clarify that even if there is no net energy generated, there is still an impact on the net flow at the transformer station, which must be accounted for in connecting generation.

Economic Connection Test Results

There has been no Economic Connection Test performed to date.

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

Given the insignificant discrepancy on the tracking of FIT and microFIT activities, the OPA finds that LUI's GEA Plan as filed is reasonably consistent with the OPA's information regarding known renewable energy generation connections.

The OPA appreciates the opportunity to comment on LUI's Basic GEA Plan.

APPENDIX B – BASIC GREEN ENERGY PLAN

Lakefront Utilities Inc.

BASIC GREEN ENERGY PLAN, May 16th, 2011

1. Introduction

As part of the 2012 Cost of Service Rate Application filing, Lakefront Utilities Inc. (LUI) is submitting a basic Green Energy Plan to update the Ontario Energy Board on LUI's ability to connect renewable generation and the required distribution system expansion to accommodate these connections.

LUI is an urban electric distribution company servicing the Municipalities of Cobourg and Colborne with a summer peaking load and a customer base of approximately 9300 electric customers. The distribution plant presently consists of a sub-transmission network (44kV), two municipal sub-stations at 27.6kV and four municipal sub-stations at 4.16kV. LUI is in the process of upgrading the inefficient, higher distribution loss 4.16kV system to a new 27.6kV distribution system throughout Cobourg. An additional 27.6kV municipal sub-station is required to complete the transition from 4.16kV to 27.6kV.

Renewable generation potential for LUI's distribution service territory is comprised primarily of solar (PV) rooftop and ground mounted installations. To date the total planned and proposed renewable generation in LUI distribution service territory is approximately 226kW for Micro-FIT and 3,480kW for FIT.

2. Current Assessment

LUI distribution service territory consists of two geographically separated municipalities made up of the towns of Cobourg and Colborne. All electric distribution customers surrounding Cobourg and Colborne are serviced by Hydro One distribution.

Cobourg's wholesale electric supply comes from two Hydro One 44kV sub-transmission express feeders originating at Port Hope TS DESN2. Port Hope TS DESN2 (BY buss) is shared between Lakefront Utility Inc. (M2 and M4) and Veridian Connections (M1 and M3). Hydro One distribution is embedded in Veridian Connection's sub-transmission system. Port Hope TS DESN2's total thermal capacity posted on Hydro One's web site is 67.2MW. As of March 30th, 2011 the total applications for renewable generation connections to Port Hope TS DESN2 is 10MW leaving a total of 57.2MW of thermal capacity at Port Hope TS DESN2.

Cobourg's electric distribution is made up of two 27.6kV transformer stations with a total feeder count of four and four 4.16kV sub-stations with a total feeder count of five. The planned and approved conversion of the existing inefficient 4.16kV distribution system will require the completion of a third strategically located 27.6kV municipal sub-station

Lakefront Utilities Inc.

within the next two to three years to enable the transfer of existing load and permit the discontinuance of the existing four 4.16kV substations.

Colborne's electric distribution consists of two 4.16kV municipal sub-stations that are embedded in Hydro One's 44kV sub-transmission system. Both 4.16kV stations are connected to the same Hydro One 44kV sub-transmission line. This 44kV line (M16) originates at Port Hope TS DESN1 and is shared by other Hydro One distribution stations and Hydro One customers. Port Hope TS DESN1's total thermal capacity posted on Hydro One's web site is 54.7MW.

As of May 11, 2011, Hydro One has informed LUI that the total applications for renewable generation connections to Port Hope TS DESN1 has reached the total connectable capacity of Port Hope TS DESN1 leaving no additional capacity for any new renewable generation connections in Colborne. As new renewable generation connection applications are received by LUI for Colborne, LUI will contact Hydro One to determine if capacity for connection has come available.

A summary of feeders to which existing and proposed micro-FIT and FIT installations are to be connected and their available feeder is provided in **Appendix A**.

2.1 Identification of Expenditures

Currently, LUI has no renewable enabling (GEA) capital expenditures related to infrastructure upgrade planned in its forecasted five year capital plan.

LUI has capital investment plans to complete an upgrade to its remaining 4.16kV electric distribution in Cobourg to 27.6kV. A new municipal sub-station is required to allow the transfer of load and the decommissioning of the existing four 4.16kV municipal sub-stations. The capital expenditure required to complete the upgrade from 4.16kV to 27.6kV will be appropriately included in the 2012 Cost of Service Rate application.

2.2 Unique Challenges /Opportunities

Lakefront Utility Inc. serves an urban customer base load made up of residential, small to medium commercial and industrial customers.

The majority of connected and proposed green energy connections in Cobourg are made up of rooftop and free standing micro-FIT projects. FIT projects will typically be installed by commercial and industrial customers with a large rooftop foot print. Large

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solar (PV) generation connections greater than 1MW are not foreseen due to limited rooftop area and vacant land available in LUI's service territory for renewable generation development.

Larger renewable generation FIT applications that have been received or are expected within five years (100kW-500kW) will typically displace customer load at the host site and are not expected to be net-exporters of energy to the distribution system. For example, LUI has a proposed roof top solar project at a large manufacturing plant in Cobourg with an average load of approximately 1.5MW and an operating timetable of 24 hours, 7 days a week. The proposed renewable generation (PV) at this site is 250kW. At no time will the renewable generation's output exceed the load at the facility.

As mentioned earlier, as of May 11, 2011, Hydro One has informed LUI that the total applications for renewable generation connections to Port Hope TS DESN1(owned by Hydro One) has reached the total connectable capacity of Port Hope TS DESN1 leaving no additional capacity for any new renewable generation connections in Colborne. Therefore additional investment in renewable energy connection enabling or enhancement upgrades in LUI's Colborne distribution territory will not increase the capacity for connecting renewable generation. Upgrades to Hydro One's system will be required to enable further renewable generation connections in the Town of Colborne.

3. Planned Evolution of the Distribution System to Accommodate Renewable Generation

To forecast the uptake of future renewable connections over the next five years, the following was done:

1. Existing and proposed renewable generation connections were reviewed.
2. A local public renewable generation purchasing consortium, SUN was polled for their knowledge of upcoming proposed generation projects in LUI service territory.
3. Commercial and Industrial customers with large rooftop surface area were contacted to determine if they had an interest in renewable generation at their location.

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Lakefront Utilities Inc.

BASIC GREEN ENERGY PLAN, May 16th, 2011

3.1 Existing Generation Connections and Projections

LUI's generator connection application process requires the involvement of various departments within the LDC and Hydro One. The application process includes internal review of applications by technical services, metering and distribution departments. LUI also requires approval from Hydro One for connection capacity as Hydro One is the Host distributor.

An internal excel spread sheet has been created where Lakefront Utilities documents the generator connection size, location, customer information and the date/time the applications were received. LUI also uses this excel spread sheet to document inquires from LUI customers about proposed or future renewable generation projects. As a theoretical exercise, using Appendix A in this document we can see that the total installed, applications for and inquiries for renewable generation connections in Cobourg's 4.16kV and 27.6kV is approximately 11% of the total capacity presently available in Cobourg. In addition, LUI is investing in capital to improve its distribution plant to better serve its existing and proposed load customers. This capital investment will also add renewable generation connection capacity to LUI's distribution plant.

Given this information, at this time, LUI is unable to justify additional investment in renewable energy connection enabling or enhancement upgrades due to the size and number of renewable generation connections received and projected over the next five years. However, applications will continue to be monitored and internal records updated to document the number and capacity of renewable generation connections. Once the feeder capacity limits are reached on any given feeder, renewable enabling distribution plant upgrades will be identified and scoped.

4. Smart Grid Development

LUI believes that Smart Grid initiatives within our distribution service territory need to be undertaken incrementally and form part of a realistic and sensible distribution system improvement program. At this juncture, Smart Grid activities are likely to form part of our future capital distribution system replacement plan. A detailed summary of incremental expenditures associated with specific Smart Grid activities and projects is currently being compiled.

In the interim, LUI is committed to Smart Grid activities, and is dedicated to continual education and professional development in this area.

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Lakefront Utilities Inc.

BASIC GREEN ENERGY PLAN, May 16th, 2011

Current Assessment of Smart Grid Opportunities

The following priorities related to the development of Smart Grid activities have been identified at this time:

- Smart Grid Education and Training
  - Staff session(s) to introduce and assist with the development of Smart Grid concepts and Smart Grid project identification.
  - Participation in Smart Grid committees, conferences, workshops or forums.
- Smart Grid Studies and Planning Exercises
  - When internal records indicate renewable generation outputs are reaching system capacity limits, establish a means of Real-time Monitoring.
  - Analysis of Smart Meter Load and Power Quality data to facilitate Planning and Operational activities (distribution system software modeling, outage management, etc.)
- Smart Grid Demonstration Projects
  - Improve reliability through minimization of outage duration and restoration time (installation of motor-operated switches and/or reclosers).
  - Upgrades to sub-station equipment, installation of SCADA equipment and communication networks with consideration of interoperability standards.

LUI foresees the development of a detailed plan of the incremental material system investments related to these Smart Grid development priorities within the next five years. This plan will consider LUI's Asset Management Plan and long term financial goals of the LDC when incorporating Smart Grid investments.

Lakefront Utilities Inc.

BASIC GREEN ENERGY PLAN, May 16th, 2011

Appendix A – List of Allocated Capacities for Current Micro-FIT/FIT

Summary of Micro-FIT and FIT Renewable Generation and Feeders						
Municipality	Transformer Station	Distribution Station	Feeder Number	Voltage	Generator Size (kW)	*Available Feeder Capacity (kW)
Cobourg	50M2	MS2	F10	4.16kV	0	740
	50M2	MS3	F13	4.16kV	20	605
	50M2	MS3	F14	4.16kV	20	1597
	50M2	MS3	F15	4.16kV	5.06	908
	50M2	MS5	F20	4.16kV	130.06	168
	50M2	MS28.1	F1	27.6kV	187.38	2554
	50M2	MS28.1	F2	27.6kV	279.36	1840
	50M4	MS28.2	F4	27.6kV	560.4	1796
	50M4	MS28.2	F6	27.6kV	113.96	1539
	50M2			44kV	1000	30000**
	50M4			44kV	1100	30000**
Colborne	50M16	MS1	F1	4.16kV	250	614***
	50M16	MS1	F2	4.16kV	5	437***
	50M16	MS1	F3	4.16kV	0	202***
	50M16	MS2	F4	4.16kV	5	363***
	50M16	MS2	F5	4.16kV	30	794***

Installations, Applications and Inquiries

* Available feeder capacity is subject to the existing load on feeders without the option of reverse flow relays. Reverse flow is not available on the 4.16kV system. The available capacity within Cobourg will increase with the completion of the upgrade of the 4.16kV system to 27.6kV. All existing and future 27.6kV station relays have reverse flow capabilities.

** Capacity is subject to the feeder's smallest conductor size and available capacity at Hydro One's Port Hope TS DESN 2.

*** Hydro One has determined that there is no renewable generation capacity available at Colborne due to capacity restrictions on the M16 44KV feeder supplied by Port Hope TS DESN1.

APPENDIX C – ASSET MANAGEMENT PLAN

LUI'S ASSET MANAGEMENT AND CONDITION ASSESSMENT STRATEGY

EXECUTIVE SUMMARY

Existing infrastructure in Cobourg and Colborne is aging while demand grows for better electrical distribution. This demand is in response to higher standards of safety, health, environmental protection, regulations and to some degree growth. The solution to this issue is to change the way we plan, design and manage infrastructure.

Long Range Infrastructure Planning for Lakefront Utilities Inc. ("LUI") is not a new concept. It has been widely used for many years and has evolved into what is now more commonly known as "Asset Management". LUI has reviewed all of the long range infrastructure strategies, current technical and financial practices and consolidated them into an Asset Management Plan.

The Asset Management Plan as presented in this report provides an overview of the fundamentals of an Asset Management Plan based upon best management practices obtained from other utilities and jurisdictions.

This format was selected to ensure that the asset management strategies as attached could be revised from time to time according to changes in best management practices, advances in technology, financial constraints or changes to the condition assessments.

The Asset Management Plan as presented in this report is a systematic process that allows for the maintenance, upgrading and operating of our physical assets in a cost effective manner.

By implementing an Asset Management Plan, LUI can meet new demands in a fiscally responsible and environmentally sustainable framework while preserving our quality of life.

DISCUSSION

Asset Management Plan – What is it?

An Asset Management Plan is a plan developed for the management of one (1) or more infrastructure assets within the utility that combines multi-disciplinary management techniques, including technical and financial, over the lifecycle of the asset(s) to a specified level of service in the most cost-effective manner.

Integrated asset management plans are similar to the description provided above. The integration refers to the infrastructures that share a common location within the utility corridor such as roads, curbs, gutters, sewer and water systems. Each asset has a different lifecycle which results in the need for the technical and financial experts to consult and determine, based upon the condition of each asset, the need for replacement or rehabilitation. A road that requires resurfacing drives the need to review the condition of the water and wastewater system resulting in an overall strategy. A water system may require rehabilitation hence it drives the need to renew the road and determine if a trench (asphalt patch) or the entire asphalt surface is replaced or if underground conduits need to be relocated. LUI is also a member of the Cobourg Public Works/Utilities Coordinating Committee. The primary purpose of this committee is to promote cooperation between the stakeholders, and through an exchange of information, facilitate the planning and coordination of activities within the utility and construction industries.

An Asset Management Plan also incorporates the existing preventative maintenance and risk management programs to preclude the risk of failure. The preventative maintenance component ensures that the day-to-day wear and tear on the asset is dealt with to ensure that the asset can reach its expected lifecycle. The risk management component ensures that Staff manages the risk through due diligence.

Asset Management Plan – What are the benefits?

Specific benefits associated with an Asset Management Plan are:

- Facilitates the establishment and subsequent implementation of policy objectives and the related measurement of performance;
- Avoids problems and potential crises;
- Provides consistent levels of service to the public;
- Leads to more effective communications with ratepayers, elected officials, financial rating organizations and regulatory agencies;
- Reduces lifecycle costs;
- Allows for better decision making regarding resource allocation;

- Reduces risk to the utility;
- Allows for more effective financial planning;
- Leads to more efficient data management;
- Results in positive institutional change.

Asset Management Plan – What are the key principles?

Asset management can be characterized by the following key principles:

- A strategic and proactive approach that places a premium on data, information, collaboration and interdisciplinary management;
- A comprehensive long-term view of infrastructure performance and cost;
- An explicit, visible and transparent approach that requires effective communication among all stakeholders;
- A business case involving investment choices that are policy driven with tradeoffs among competing priorities.

Asset Management Plan – What are the essential components?

In order for an Asset Management Plan to fulfill the principles of asset management, the following essential components must be contained in the overall plan:

1. Asset Value:

   All electrical infrastructure assets have a monetary value. Administration has determined the actual capital value for the majority of the assets and some others provided an estimate. The finance Department has worked with the Operations Department who conducted an inspection study. The study determines the actual value of the assets through a capital cost analysis and ensure that the process for identification and tracking of capital assets in the future is well defined.

2. Lifecycle Management:

   All assets have a limited life expectancy. To some degree the rate of deterioration can be estimated. A decision made at any point in time in the lifecycle of an asset has an effect on the remaining life, and may have operational implications and related costs. The lifecycle for each asset as presented in this report is contained in the attachments.

3. Sustainability:

In terms of asset management, sustainable development has been defined as "meeting the needs of the present generation without compromising the ability of the future generations to meet their own needs". The Asset Management Plan needs to identify a financial plan over the long term to ensure that sufficient monies are available. These monies provide the resources required to operate, rehabilitate, and ultimately replace the asset at the optimal time with the intention of achieving the lowest lifecycle cost. In other words, an asset that receives no preventative maintenance, and has no associated asset management plan will require full replacement (at a much higher cost) well before it reaches the end of its life cycle. The plan helps make sure that current users pay a fair share for the service they receive and that future users pay a similar cost for the same level of service.

4. Integration of Technical and Financial Plans:

   The technical plan must minimize lifecycle costs for the infrastructure while maintaining an adequate level of service at the lowest possible level of risk. The financial plan must identify the financial investment required per year for each asset over the long term, including any larger than normal expenditures to meet the requirements of the technical plan. Ideally the two plans should be integrated so the relationship between the level of service and the cost can be quantified. The plans attached to this report integrate the financial investment level required to the level of service. The technical and financial relationship may change from time to time depending on the outcome of the condition surveys.

5. Risk Assessment:

   Risk should be managed in any decision making process. The owner of the assets should analyze and document acceptable risk tolerance. In LUI's' case, the probability of failure is taken into account while the condition of the asset is being analyzed. The condition survey leads to determining the rate of failure and the consequences of such failure. Risk factors can include financial, environmental, regulatory/legal and public health and safety.

6. Performance Measurement:

   To optimize an Asset Management Plan, performance of the assets and rehabilitation strategies should be monitored regularly and adjustments made at the appropriate stage in the asset lifecycle to achieve an acceptable balance between cost and the performance (level of service). LUI has undertaken such performance measurements. These benchmarks (for some of the

assets) have been compiled into a comprehensive database that can be easily accessible and can be used to determine the performance of the asset.

Other Initiatives

Another undertaking of LUI is the purchase of an integrated infrastructure asset management software, which has been purchased and is currently being deployed. This asset management tool assists with the overall administration of the asset management plans described within this report. The integrated infrastructure maintenance management system allows the maintenance and engineering staff access to the same information on a real time basis and tracks activities associated with respect to inventories. This system also helps to monitor scheduled and unscheduled maintenance, and to record and monitor inspection results and work order schedules. The common database also ensures that everyone is working from the same page. The data and historical information is contained within one application, making it efficient and consistent. The end result is that capital projects can be better planned, and the long term planning associated with the asset management plan can be better managed with the intention of maximizing the life of the asset.

Conclusion

It is concluded that the Asset Management Plan as presented in this report is a systematic process that allows for the maintenance, upgrading and the operating of our physical assets in a cost effective manner and that by implementing an Asset Management Plan, LUI can meet the new demands within a fiscally responsible and environmentally sustainable framework while preserving our quality of life.

We have included three main categories of assets below in which asset condition assessments were done, using the principles described in this report. LUI is committed to continue deployment of the asset management software, to build and enhance this tool to provide us with accurate purchase, installation and inspection dates plus financial evaluation and forecasting models.

ASSET MANAGEMENT STRATEGY

Asset:	**Corporate Facilities**
Inventory:	Office Building, Garage and Substation facilities
Anticipated Asset Life Cycle:	Life Cycles can vary from 10yrs to 50yrs. A hot water tank replacement cycle would be in the 10yr range, a roof membrance in the 20yr range, heating ventilation, air conditioning in the 15-25 yr range and a building super structure would be in the 50yr range. These life cycles assume adequate maintenance is provided through the course of the components life.
Integrated:	Individual asset components are reviewed; projects are lumped per asset to take advantage of the 'economies of scale' principle. Consideration is given to minimize the disruption of operations to a given asset over time.
Rehab and Replacement Criteria:	FCI (Facility Condition Index) is a standard ratio recognized throughout North America. THE FCI can be associated with individual assets or grouping of assets in determining the ratio of total deferred maintenance costs vs current replacement value of the asset. An FCI of under .05 is good, .05 to .10 is fair, >.10 is poor and .35 is total replacement.
Rehab and Replacement Strategies:	Asset condition summaries of the Office and Garage buildings roofs, HVAC systems and exterior building envelopes were done. The asset condition assessment identify percent used of an individual component and priortizes replacement based on actual condition, and its point in time of its Life Cycle. Five percent of the Roof is upgraded each year to allow replacements within the life expectancy limits. All roof replacements will include new rood insuation, increasing energy efficiency and reducing energy consumption. The HVAC units are replaced/upgraded to meet life cycle, industry, technological and safety standards. Prior to replacement of the entire system, it is reviewed for potential efficiencies and all new equipment installed is energy efficient.
Life Cycle Consequences:	Increased deterioration of building and properties, health and safety concerns, inefficient operation, higher operating costs, accelerated depreciation of company assets.
Integrated Asset Priorities:	Replacement is based on actual condition, the point in time witin its life cycle, the availability to complete the replacement with minimal disruption to the service delivery within the asset.
Charts/Tables:	
Estimated Cost per year for strategy described:	$100K

ASSET MANAGEMENT STRATEGY

Asset:	**Vehicles**
Inventory:	Fleet Value Summary December 2010 Current Value: $609,832 # of units: 9 Acquisition Value $1.05M Replacement Value: $1.15M
Anticipated Asset Life Cycle:	Varies depending on vehicle type, i.e. pickups - 9 yrs, light duty trucks - 12 yrs, heavy trucks 12 to 15 years
Integrated:	With financial planning, technological advances, environmental regulations, operational changes, service increases/decreases
Rehab and Replacement Criteria:	Lifecycle cost analysis considering depreciation, fuel, repair and downtime costs identify optimal replacement year for vehicle classes.
Rehab and Replacement Strategies:	Review usage to warrant replacement, repair costs not to exceed 50% of replacement costs. Review seasonal rental opportunities and refurbishing strategies.
Life Cycle Consequences:	Health and safety concerns, inefficient operation, higher operating costs.
Integrated Asset Priorities:	
Charts/Tables:	
Estimated Cost per year for strategy described:	$140K

ASSET MANAGEMENT STRATEGY

Asset:	**Poles**
Inventory:	Approx 3200 poles; Wood, Concrete & Fiberglass composite at 30', 40', 45', 55', 60', 70'
Anticipated Asset Life Cycle:	Life Cycles can vary from 25yrs to 60yrs. These life cycles are contingent upon other factors such as location to roads, sidewalks, ditches, weatherization, salt erosions, species of trees of the wood poles, preservative treatments, etc.
Integrated:	With GIS mapping, asset management database, financial planning, Municipal and environmental regulations, operational changes
Rehab and Replacement Criteria:	Lifecycle cost analysis considering depreciation, restoring and reinforcing, safety, and asset-preservation costs, identify optimal replacement timing for poles.
Rehab and Replacement Strategies:	Asset condition summaries of the poles are done by linemen and engineering students. The pole is evaluated numerically between 1 and 10 with a multiplier of 5 years per unit (ie. 3 is actually 3 x 5 years = 15 years approximately of remaining life). The age of the pole is determined by year of substation installation, date of transformers on the pole line, stamps on the poles if visible, appearance of materials, building construction for the general area, etc. The asset condition assessment identify and priortizes replacement based on actual condition. We are building a database as we continue to improve and enhance our GIS mapping and asset management tool. By querying the database spreadsheet, we can determine the number of poles, type and height with remaining life based on the inspection that will require replacements in the next 3 to 5 years to budget accordingly. (*A sample of the database spreadsheet is attached*)
Life Cycle Consequences:	Increased deterioration of poles, major health and safety concerns, higher operating costs.
Integrated Asset Priorities:	Replacement is based on actual condition, the point in time witin its life cycle, the availability to complete the replacement with minimal disruption to the service delivery within the asset.
Charts/Tables:	
Estimated Cost per year for strategy described:	$325K

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ID	PT_ID	NORTHING	EASTING	ELEVATION	DESC	Notes	Notes2	Street	PoleID	Height	Condition
1034	1288	4871383.2692	724955.0825	83.1993	HP	Wood		567 EWING ST	1013	40.0	2
1079	569	4871177.0158	724902.3473	83.0483	HP	Wood	No Dumping	DAINTRY CRES	1037	40.0	3
1096	382	4872656.4353	724718.1065	106.4517	HP	Concrete	No Stopping	8 STRATHY RD	617	60.0	4
1110	220	4873035.7738	724536.7617	106.2004	HP	Concrete	No Stopping	75 STRATHY RD	636	35.0	4
1135	1585	4872738.1642	724961.2695	108.6389	HP	Wood		Courthouse Road	302	55.0	3
1136	1578	4872744.6240	724975.9969	108.3175	HP	Wood		Courthouse Road	303	35.0	2
1137	1576	4872724.2259	724970.3316	107.5888	HP	Wood		555 COURTHOUSE RD	304	45.0	3
1138	1575	4872691.0008	724978.6663	104.7859	HP	Wood		575 COURTHOUSE RD	305	40.0	3
1180	732	4873503.4206	725588.5831	99.1283	HP	Wood	No Exit	300 WHITE ST	586	45.0	3

TRANSFORMER RECORD

						Date	26-Jan-09
C#	KVA	SERIAL #	PRIM. VOLT	SEC. VOLT	Pole Pad	LOCATION	DATE INSTALLED
75	100	KC89C21207	16 / 4.8	120/240	POLE	16 Coronation Cres	1990
76	100	KC89C08204	16 / 2.4	120/240	POLE	Frei & Glenhare?	1990
77	100	KC89C09204	16 / 2.4	120/240	POLE	1063 Booth St	1989
78	75	KC89C17202	16 / 2.4	120/240	POLE	?? Beatty Cres	1989
79	50	KC89E05203	16 / 2.4	120/240	POLE	137 Balls Lane	1989
80	100	KC90A03212	16 / 2.4	120/240	POLE	?? Daintry Cres	1990
81	100	BC90A02201	16 / 2.4	120/240	PAD	1012 Frei St	1990
82	25	KC90K06201	16 / 4.8	120/240	POLE	7 Acadia Dr	1990
83	50	KC90J24201	16 / 4.8	120/240	POLE	19 Orchard Ave	1990
84	50	KC90J24202	16 / 4.8	120/240	POLE	2 Maplewood Blvd	1990
85	50	KC90J24204	16 / 4.8	120/240	POLE	26 Coverdale Ave	1990
86	50	KC90J24205	16 / 4.8	120/240	POLE	16 Springbrook Rd	1990
87	50	KC90J30205	16 / 4.8	120/240	POLE	32 Coronation Cres	1990
88	50	KC90J30203	16 / 4.8	120/240	POLE	571 King St. E.	1990
89	75	KC90J29206	16 / 4.8	120/240	POLE	56 Hamilton Ave	1990
90	100	KC90J26201	16 / 4.8	120/240	POLE	Coverdale & King St E.	1990
91	100	KC90J26203	16 / 4.8	120/240	POLE	3 Parkwood	1990
92	100	KC90J26204	16 / 4.8	120/240	POLE	9 Hawthorne	1990
93	100	KC90J26205	16 / 4.8	120/240	POLE	Fitzhugh Lane	1990
94	100	BC90A05205	16 / 2400	120/240	PAD	Field Crt	1990
95	100	KC92A14204	16 / 2400	120/240	POLE	Frei St	1992

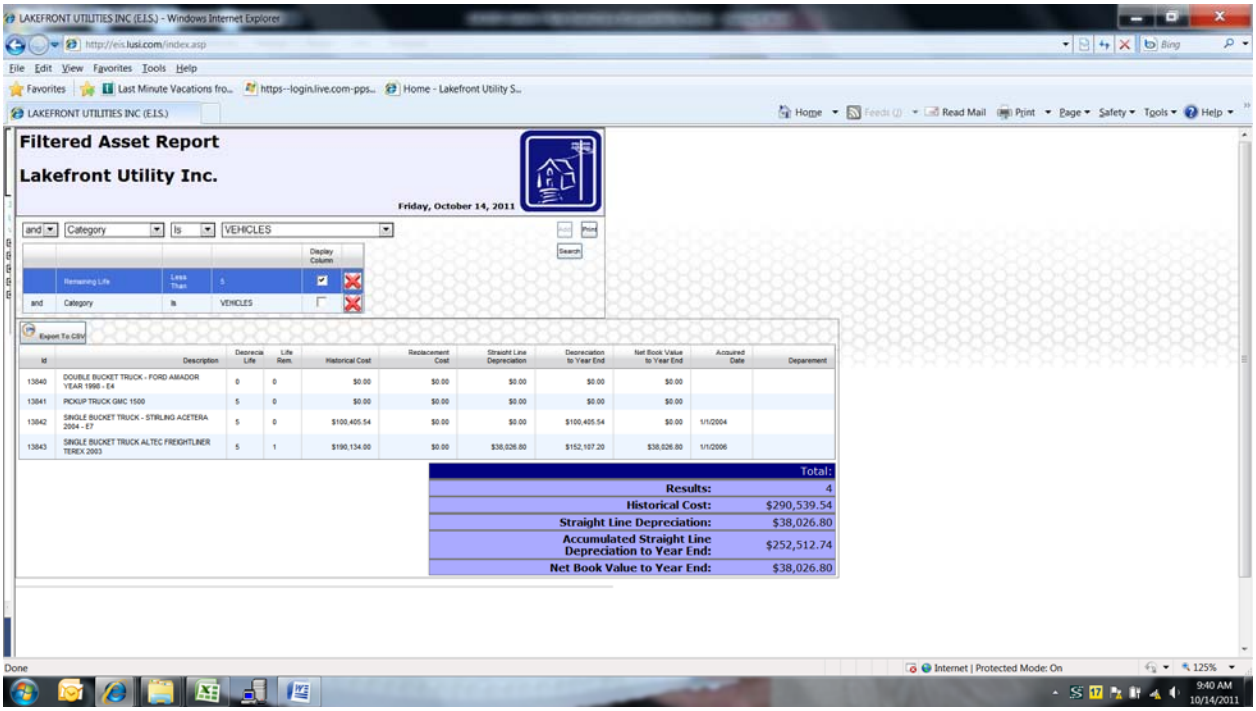
APPENDIX D – ASSET MANAGEMENT TOOL

Filtered Asset Report

Lakefront Utility Inc.

Thursday, October 06, 2011

Id	Description	Deprec Life	Life Rem.	Historical Cost	Replacement Cost	Straight Line Depreciation	Depreciation to Year End	Net Book Value to Year End	Acquired Date	Dep
13840	DOUBLE BUCKET TRUCK - FORD AMADOR YEAR 1998 - E4	0	0	$0.00	$0.00	$0.00	$0.00	$0.00		
13841	PICKUP TRUCK GMC 1500	5	0	$0.00	$0.00	$0.00	$0.00	$0.00		
13842	SINGLE BUCKET TRUCK - STIRLING ACETERA 2004 - E7	5	0	$100,405.54	$0.00	$0.00	$100,405.54	$0.00	1/1/2004	
13843	SINGLE BUCKET TRUCK ALTEC FREIGHTLINER TEREX 2003	5	1	$190,134.00	$0.00	$38,026.80	$152,107.20	$38,026.80	1/1/2006	
13844	SUV HONDA CRV 2008 - E10	8	5	$29,742.33	$0.00	$3,717.79	$11,153.38	$18,588.95	1/1/2007	
13845	VAN DOGE CARAVAN 2008 - E10	8	5	$26,091.43	$0.00	$3,261.43	$9,784.28	$16,307.15	1/1/2007	
13846	DIGGER RADIAL BOOM TRUCK FREIGHTLINER TEREX 2009	8	6	$284,466.60	$0.00	$35,558.33	$53,337.50	$231,129.10	1/1/2008	
13847	SUV DODGE NITRO TRUCK 2009 - E1	8	7	$24,896.00	$0.00	$3,112.00	$1,556.00	$23,340.00	1/1/2009	
13848	PICKUP TRUCK GMC 1500 2009 - E2	8	7	$23,596.00	$0.00	$2,949.50	$1,474.75	$22,121.25	1/1/2009	
13849	WARRANTY WAJAX 2009 DIGGER - E5	8	7	$6,296.40	$0.00	$787.05	$393.45	$5,902.94	1/1/2009	
13914	Truck 2010 Aerial/Digger/Bucket	10	9	$354,617.00	$354,617.00	$35,461.70	$17,730.85	$336,886.15	12/1/2010	



APPENDIX E – DRAFT CAPITALIZATION POLICY UNDER REVIEW

Intent

This policy has been developed to ensure that Lakefront Group of Companies properly accounts for the investment in its property, plant and equipment and the changes in such investments. These guidelines were written in accordance with Generally Accepted Accounting Principles (GAAP) and amended to include changes with respect to International Financial Reporting Standards (IFRS) where required, auditor requirements and Ontario Energy Board's Accounting Procedures Handbook.

Capitalization Guidelines

A capital asset is broadly defined as being one that will provide future economic benefits to the organization. The definition in the OEB Handbook includes items which:

1. are held for use in the production or supply of goods and services, for rental to others, for administrative purposes or for the development, construction, maintenance or repair of other capital assets;
2. have been acquired, constructed or developed with the intention of being used on a continuing basis; **and,**
3. are not intended for sale in the ordinary course of business.

Fixed assets have a useful life of more than one year and are subject to depreciation. Any directly attributable expenditures to acquire, construct or better that asset, should therefore be capitalized. All other expenditures should be expensed as a period expense in the year they occur.

Professional judgment must be used to determine when an expense is classified as capital or an operating expense. A betterment (capitalized) will enhance the service potential of an existing asset by increasing its service capacity, lowering the operational costs associated with the asset, extending the useful life of the asset, or improving the output of that asset. If the expenditure does not meet these tests, it will likely be considered an expense. Period expenses generally do not result in an improvement to the existing asset but rather, the expense is required to keep the asset operating in the same capacity as it was originally.

In order to be capitalized, an item must meet the minimum threshold requirement of two hundred dollars ($500.00) unless it is a small vital component in a larger capital asset (i.e. ties at

the base of a pole), then the item should still be capitalized. The minimum threshold may be overridden, based on justified professional judgment.

Value

The value of a capital asset is the cash price equivalent at the purchase date. The cash price of a capital asset includes:

a) its purchase price, including an importing duties and non-refundable taxes, after deducting trade discounts and rebates.
b) any costs that directly attributed to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by Lakefront Group of Companies.
c) the initial estimate of the costs of dismantling and removing the item and restoring the site on a consequence of having used the item during a particular period for purposes other than to produce inventories during that period.

Residual Value & Useful Life

Lakefront Group of Companies will review at least annually the residual value and useful life of each asset. Reviews ensure that the carrying amount does not differ materially from what would be determined using fair value at the balance sheet date.

Increases and decreases in capital assets during reviews will be reported as a profit or loss in equity. If expectations differ from previous estimates the changes shall be accounted for as a change in estimate in accordance with IAS 8.

The following factors will be considered when determining the useful life of an asset:

a) Expected usage of the asset. Usage is assessed by reference to the asset's expected capacity or physical output.
b) Expected physical wear and tear, which depends on operational factors such as the number of shifts for which the asset is to be used and the repair and maintenance program, and the care and maintenance of the asset while idle.
c) Technical or commercial obsolescence arising from changes or improvements in production, or from a change in the market demand for the product or service output of the asset.
d) Legal or similar limits on the use of the asset, such as the expiry dates of related leases.
e) Kinetix report published by the OEB, to assist in determining the typical useful lives under IFRS.
f) Professional judgment

Acknowledgement & Agreement

I, (Employee Name), acknowledge that I have read and understand the Capitalization Policy of Lakefront Group of Companies. Further, I agree to adhere to this Policy and will ensure that employees working under my direction adhere to these guiding principles. I understand that if I violate the rules/procedures outlined in this Policy, I may face corrective action, up to and including termination of employment.

Name: _____

Signature: _____

Date: _____

Witness: _____

Appendix F Conversion Assessment

APPENDIX V

EnerSpectrum Group

Lakefront Utilities Inc.

Conversion of F9 from 4160 V to 27,600 V

Distribution System Loss Assessment

E4019

January 21, 2005

Prepared by:	Approved by:
Original signed by R D Ryan	*Original signed by Bart Burman*
R.D. Ryan, MBA, P.Eng. Partner	Bart Burman, MBA, BA.Sc. P.Eng. Managing Partner

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Introduction

On October 22, 2004, Lakefront Utilities Inc. contracted EnerSpectrum Group to provide an assessment of the effect on distribution losses of a feeder voltage conversion. The feeder, F9 from MS 2 in Cobourg, feeds a predominately residential neighbourhood in the central downtown area. The feeder is currently operated at 4,160V, supplied from a 5,000 kVA 44kV/4kV transformer at MS 2. Post-conversion, the feeder would operate at 27,600 V supplied from existing 27,600 facilities in the area.

This analysis is being made in support of Lakefront Utilities Inc. line loss mitigation program which is part of their Conservation and Demand Management Plan.

The following seven steps were undertaken to assemble data and model the impact of 27.6/16 kV conversion on the distribution system:

1. Identify existing feeder and load to be displaced through conversion
Physical route, electrical characteristics, load connection points and customer characteristics, and other relevant data were assembled for F9.
2. Identify 27.6/16 kV feeder to accommodate converted load
Routing and connection data pertaining to the existing 27.6/16 kV feeder F2 were reviewed.
3. Identify substation being off loaded
Electrical characteristics of MS 2 transformer and loading were reviewed.
4. Identify 27.6/16 kV substation accommodating converted load
Electrical characteristics of MS 28 – 1 transformer and loading were reviewed.
5. Assess 44kV system impacts
Routing and connection data pertaining to the 44 kV to both MS 28-1 and MS 2 were reviewed.
6. Model feeders
Created system models and entered data obtained from earlier steps to identify losses for F9 as a 4,160 V and as converted to a 27.6 KV feeder.

This report documents system impacts and the loss reduction in kW from conversions and estimates ranges of benefits from loss mitigation. This report can be used by Lakefront Utilities to support submissions to regulatory authorities.

F9 4,160 V Model

The 4,160 V feeder F9 was modeled in its existing configuration. The line layout for the model was derived from the AutoCAD information supplied. All overhead conductors were modeled as #3/0 copper. The underground section of F9 on Division Street was modeled as #4/0 Al XLPE.

The 5,000 kVA 44kV/4,160V supply transformer was modeled at MS 2 based on nameplate data. All distribution transformers were modeled using typical characteristics

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for each size of transformer. The transformers of appropriate size and configuration were attached to the line sections based on location information supplied. Two single phase transformers near 437 John Street were lacking phase information. These were modeled on the red phase since this phase is the most heavily loaded. One transformer near 15 Swayne Street was supplied with an unknown kVA rating. This transformer was modeled as 50 kVA. All transformers were modeled on 100% tap.

Loads were assigned to each transformer based on the nameplate rating of the transformer. All loads were modeled as residential unless specifically identified as commercial. No industrial loads were identified. One modification was made when information was provided that two 250 kVA single phase pad mount transformers, off College Street north of King Street East, feed Seniors residences that had been converted to gas for heat and hot water. The loads on these transformers were reduced to half of nameplate rating.

F9 27,600 V Model

Once the 4,160 V model was developed, a copy was made and converted to 27,600 V, maintaining all load and line configurations. The 5,000 kVA supply transformer was replaced with a 27,600 V source at MS 2. All distribution transformers were replaced with 27,600 V transformers having typical characteristics.

Modeling Results

At a site visit to MS 2 on October 22, 2004, load readings were recorded for F9 as follows:
Time 10:00 AM

- Red Phase 310 Amps,
- White Phase 260 Amps,
- Blue Phase 300 Amps.

The first model run was performed by scaling the loads to produce an average current at 10:00 AM of 290 Amps to match the October 22 readings. The model was run for a full 24 hours for October 22, with the same load scaling for each hour as at 10:00 AM. The 26,600 V model was run for the same 24 hour period using the same load scaling. The resulting currents are shown in Figure 1 and 2 below. Figures 3 and 4 show the feeder load and the associated losses relating to these currents.

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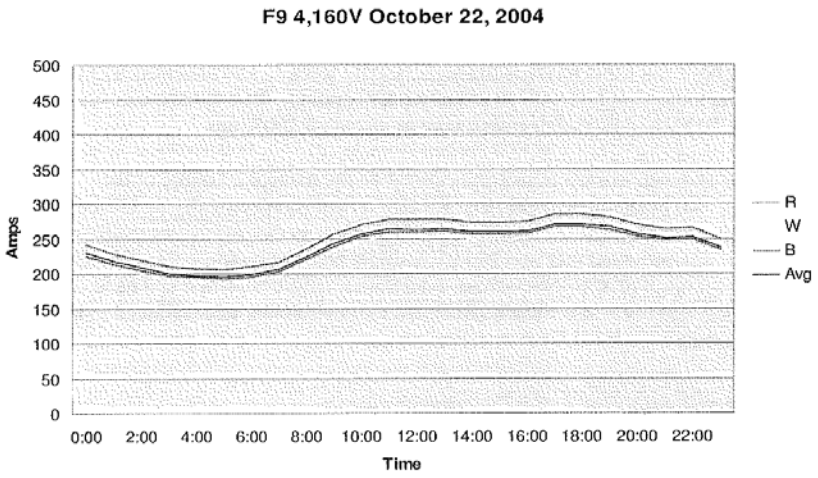

Figure 1
F9 4,160 V Model Adjusted to Match 10:00 AM Currents

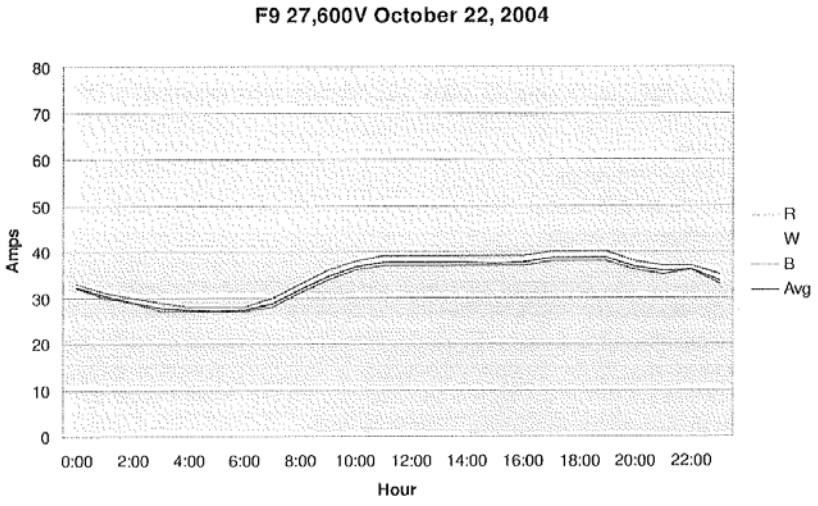

Figure 2
F9 27,600 V Model Equivalent, Adjusted to Match 10:00 AM Currents

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Feeder Voltage Conversion Loss Assessment
Lakefront Utilities Inc.

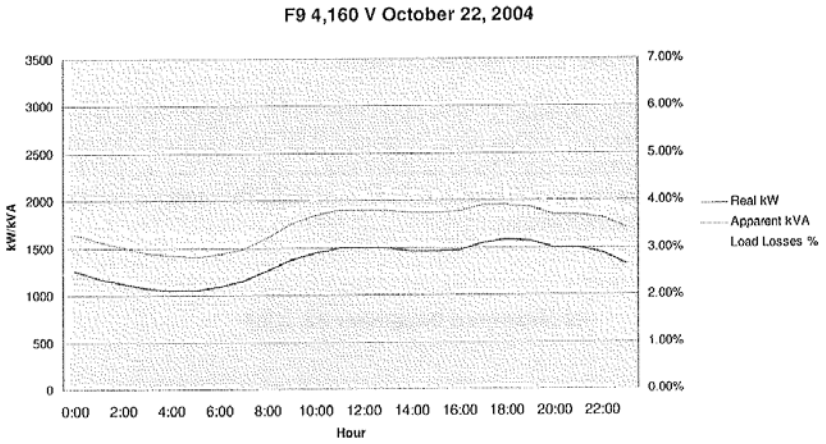

Figure 3
F9 4,160 V Model Adjusted to Match 10:00 AM Currents

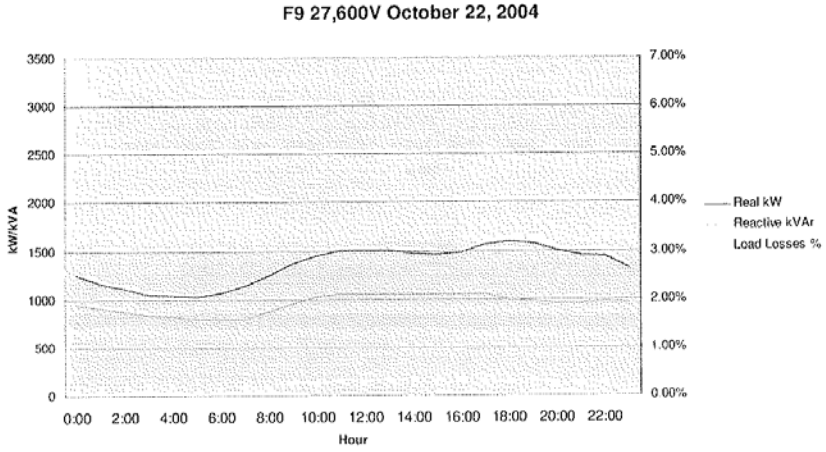

Figure 4
F9 27,600 V Model Equivalent, Adjusted to Match 10:00 AM Currents

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The analysis shows that, for the 24 hour period modeled, on the 4,160 V system, 32,410 kWh were delivered, of which 1,249 kWh were losses, while on the equivalent 27,600 V system, 32,366 kWh were delivered, but losses were only 85 kWh. This is a decrease from 3.85% losses to 0.26% losses over the 24 hours.

A recording ammeter was installed to collect load data for F9. The period of recorded data runs from 3: PM (1500) on December 21 through 9:00 AM (0900) on December 23. The 24 hour period for December 22 was modeled and compared to the recorded values. Figures 5, 6 and 7 show the currents measured and modeled. The modeled energy and losses are shown in figures 8 and 9.

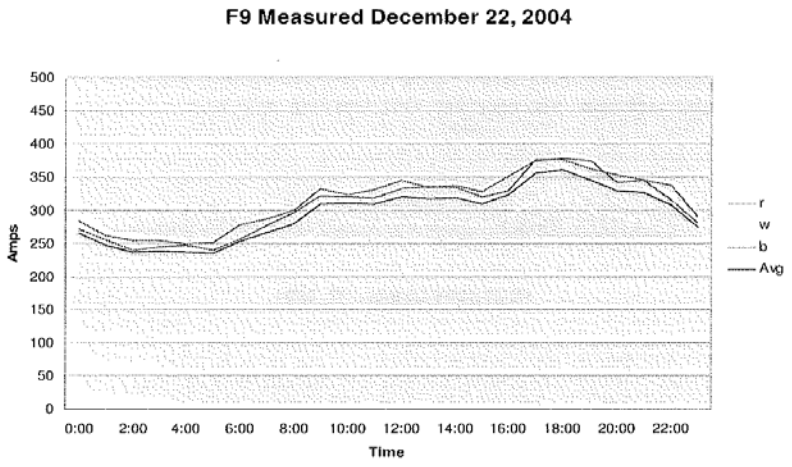

Figure 5
F9 4,160 V Measured Current December 22, 2004

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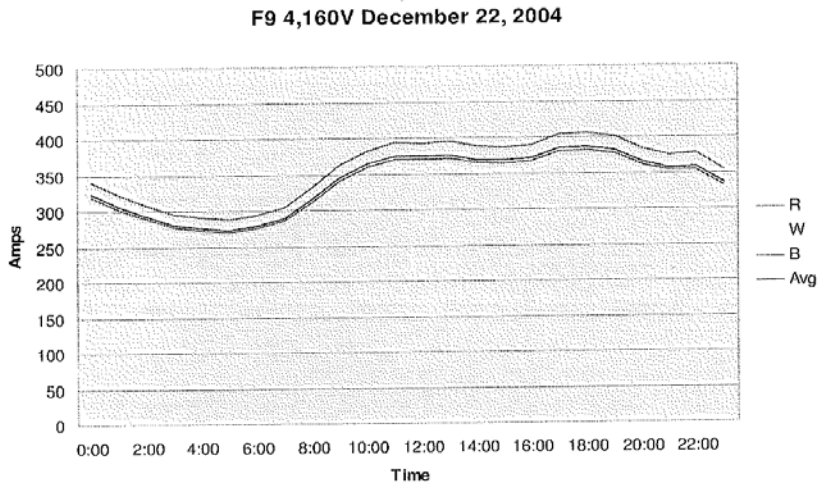

Figure 6
F9 4,160 V Modeled Current December 22, 2004

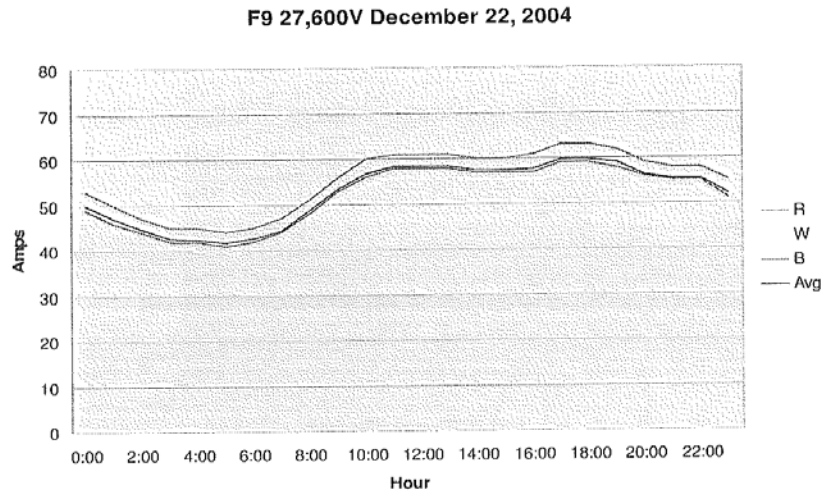

Figure 7
F9 27,600 V Modeled Current December 22, 2004

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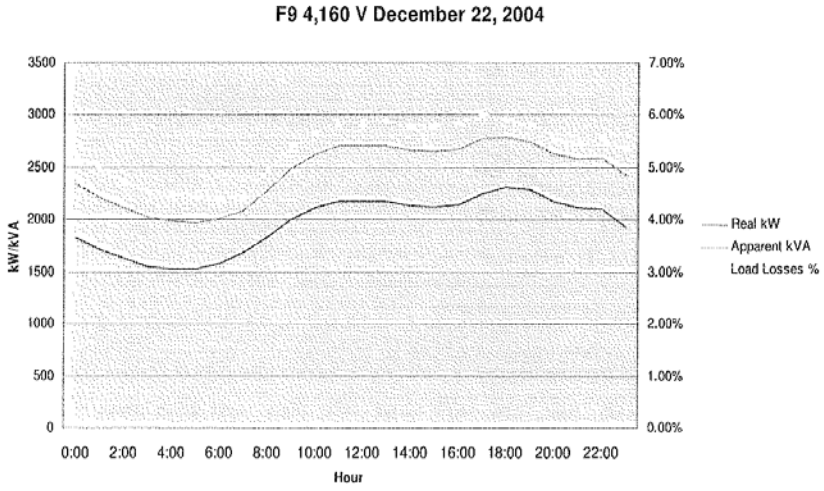

Figure 8
F9 4,160 V Modeled Energy and Loss December 22, 2004

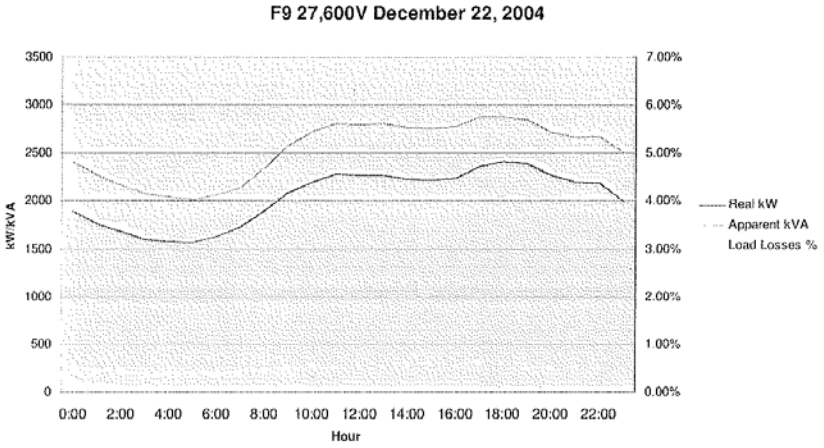

Figure 9
F9 27,600 V Modeled Energy and Loss December 22, 2004

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The analysis shows that, for the 24 hour period of December 22, 2004, on the 4,160 V system model, 41,191 kWh were delivered, of which 1,969 kWh were losses, while on the equivalent 27,600 V system, 42,552 kWh were delivered, but losses were only 193 kWh. This is a decrease from 4.78% losses to 0.42% losses over the 24 hours.

The average current over the 24 hour period of December 22, 2004 for the measured and modeled cases is fairly well correlated. This is shown in Figure 10. The modeled average current has a slightly flatter curve over the 24 hour period than the measured values.

The individual phase currents are shown in Figures 5 and 6. The measured phase currents have a larger dispersion between phases than the model provides. To assess the affects of this, the model was run using a method which adjusts the resulting currents to closely match the measured phase currents. This was done for 08:00 where the average currents are very closely aligned. The results are as follows:

R	W	B	Avg	
300	242	297	280	Measured data
300	240	298	279	Data Adjusted Model
294	268	275	279	Model

The impact of this adjustment on the energy delivered and loss sustained is:

	Delivered	Load Losses		
Hour	kW	kW	%	
8:00	1608	71	4.42%	Data Adjusted Model
	1606	70	4.36%	Model

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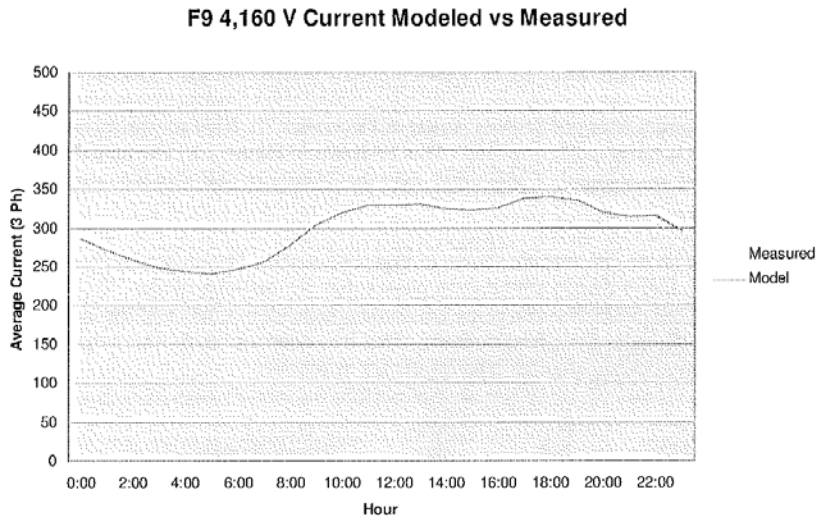

Figure 10
F9 Average Current Modeled vs. Measured

The above analysis indicates that the model is a fair representation of the system.

The October 22 analysis results in a peak transformer loading of 1,952 kVA. This is 39% of the 5,000 kVA rating. The December 22 analysis produces a peak loading of 2,449 kVA which is 49% of transformer rating. Two further analyses were performed to provide a range of coverage of supply transformer loading. A low load scenario was run at 30% of supply transformer rating. This drops the 27,600 V line loss below 1 kW. The second scenario increased load until the 120 V secondary voltage dropped to 108 V along King Street East. This resulted in a 2,967 kVA load on the supply transformer, 59% of rating. These results are shown in Figures 11 through 18.

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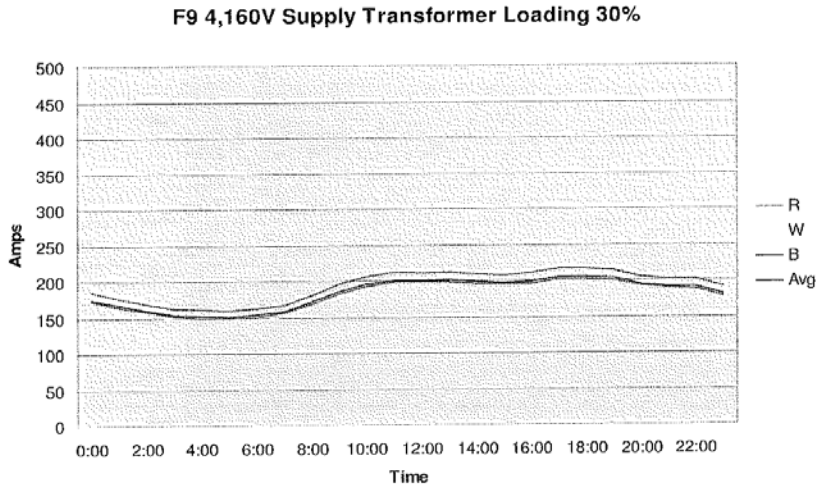

Figure 11
F9 4,160 Current at 30% Transformer Loading

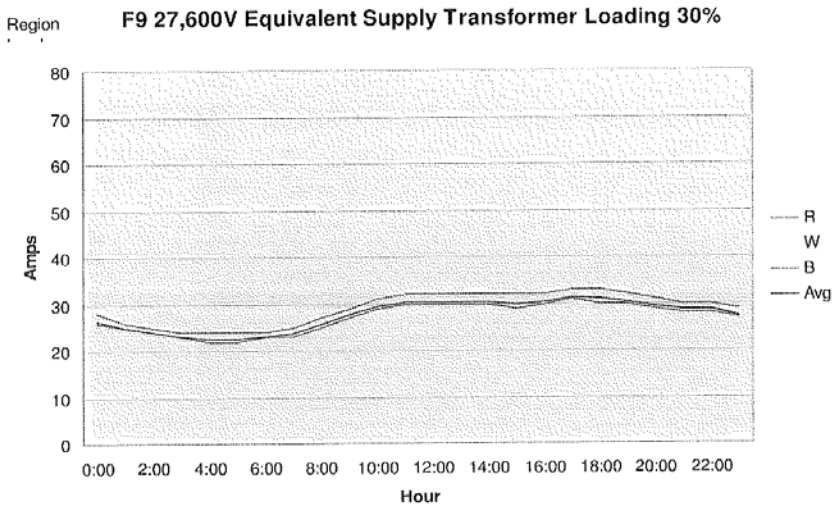

Figure 12
F9 27,600 Current at Equivalent 30% Transformer Loading

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Feeder Voltage Conversion Loss Assessment
Lakefront Utilities Inc.

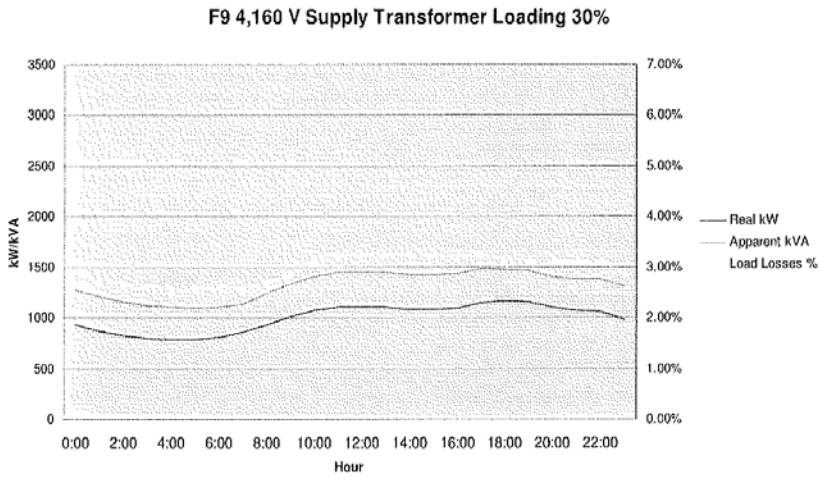

Figure 13
F9 4,160 Load and Loss at 30% Transformer Loading

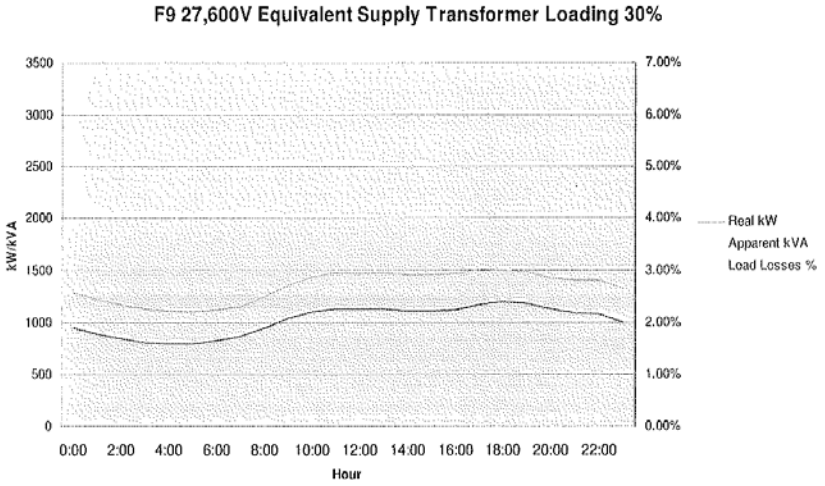

Figure 14
F9 27,600 Load and Loss at Equivalent 30% Transformer Loading

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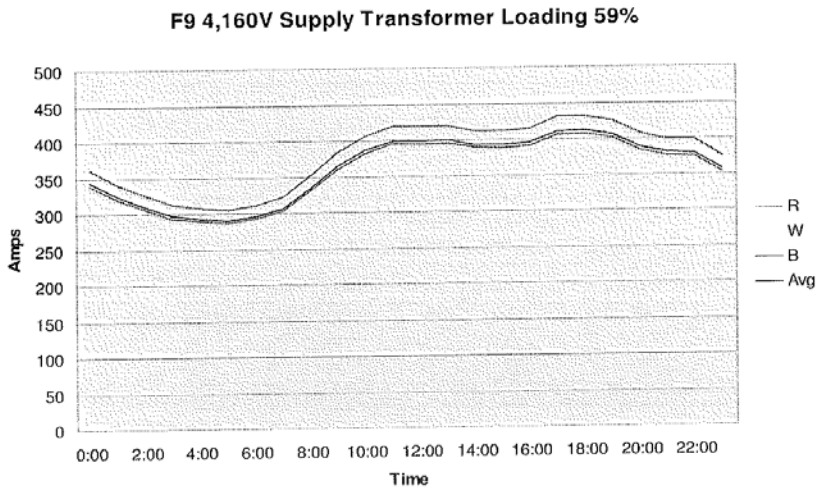

Figure 15
F9 4,160 Current at 59% Transformer Loading

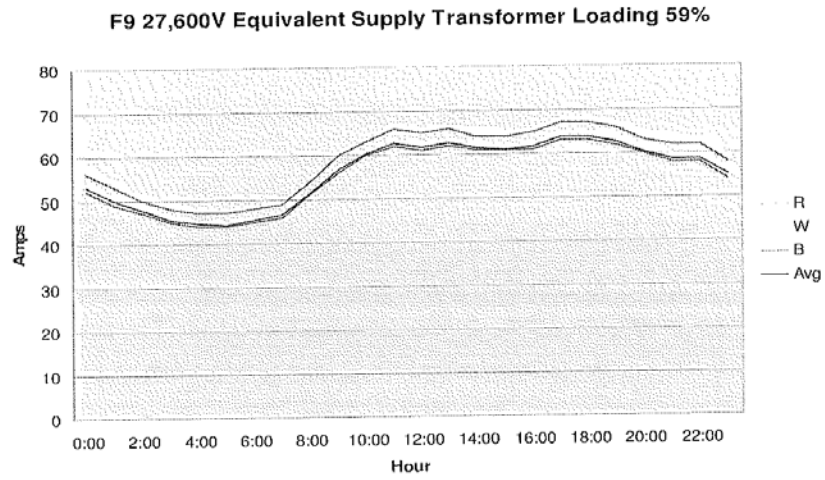

Figure 16
F9 27,600 Current at Equivalent 59% Transformer Loading

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Feeder Voltage Conversion Loss Assessment
Lakefront Utilities Inc.

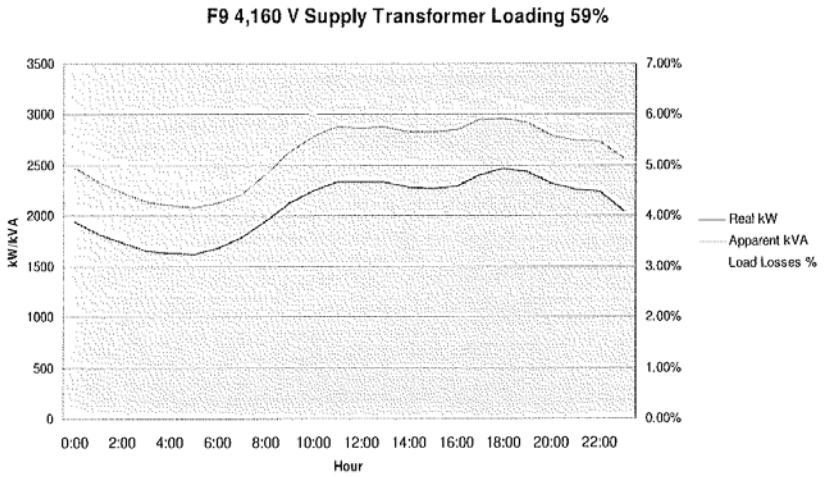

Figure 17
F9 4,160 Load and Loss at 59% Transformer Loading

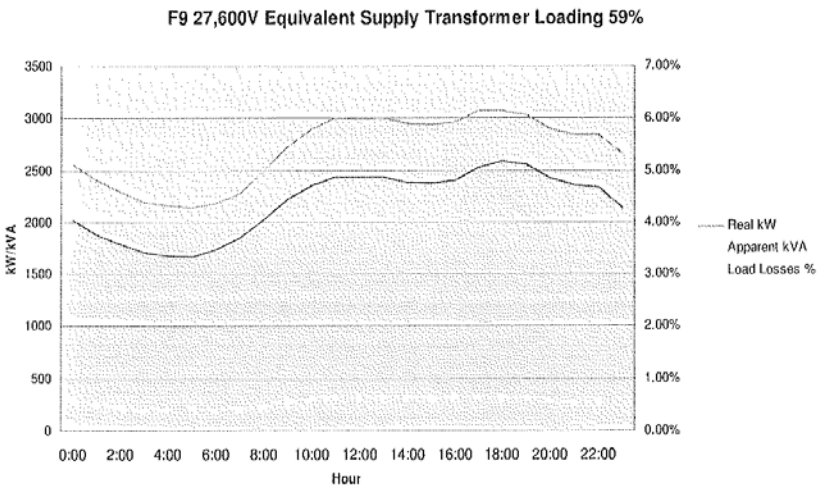

Figure 18
F9 27,600 Load and Loss at Equivalent 30% Transformer Loading

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The four supply transformer loading scenarios are summarized in Figure 19. This graph plots the peak kW and kVA delivered and the losses associated with that supply level. Figure 20 plots the 24 hour energy delivered and associated losses for each of the four supply levels in figure 19. These graphs can be used to estimate the level of losses associated with any system peak loading within range of the study.

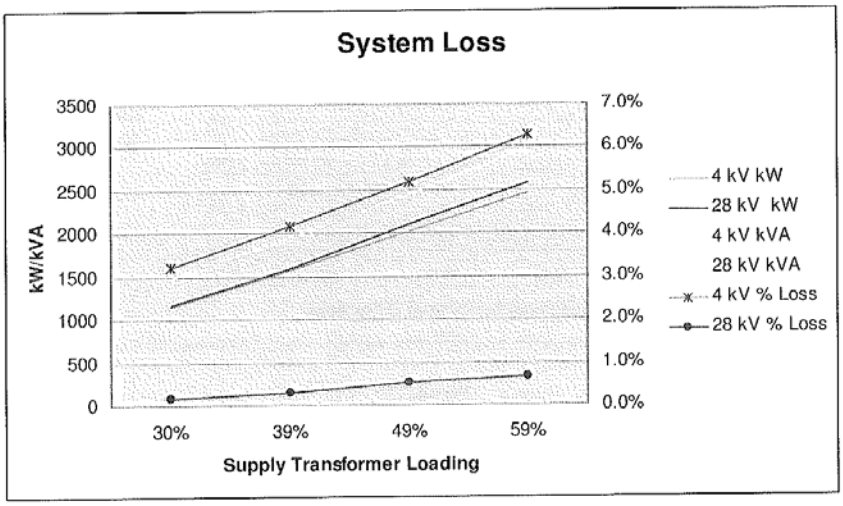

Figure 19
Peak Loss vs. Supply Transformer Loading

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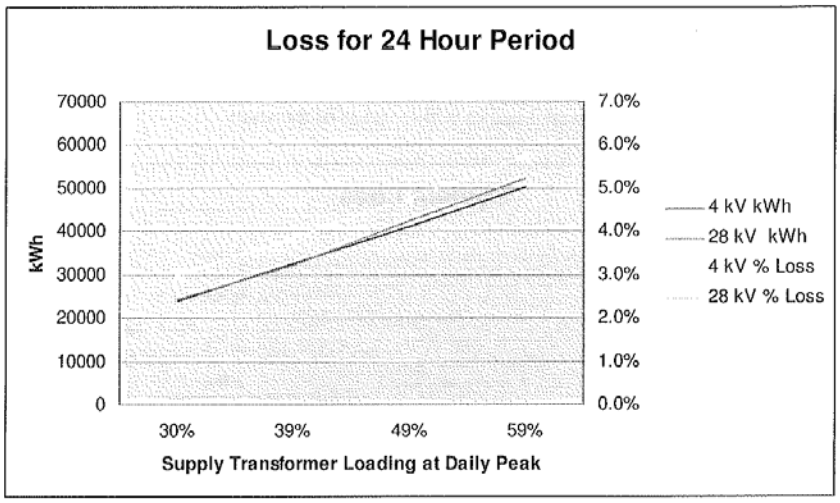

Figure 20
Energy Loss vs. Peak Transformer Loading

The above analysis demonstrates that voltage conversion of the F9 feeder from 4,160 V to 27,600 V will provide a range of loss reduction from just less than 3% for light load conditions to approximately 5% for more heavily loaded conditions.

27,600 V and 44,000 V Systems

The 27,600 V supply for the voltage conversion is from MS 28-1 through feeder F2. This feeder runs east from MS 28-1, along the railway right-of-way and south on Darcy Street past MS 2. The feeder length between the two stations is less than 2 km. This feeder is lightly loaded. The supply transformer at MS 28-1 is 20 MVA, 44 kV/27.6 kV. This transformer is also lightly loaded.

The 44,000 V supply to MS 2 and MS 28-1 stations is from the same 44,000 V feeder. This feeder runs from Highway 2, south near West Street, to the railroad. It then splits into two legs. One leg runs west to MS 28-1, the other east and south to MS 2. These runs are approximately 1 km in length with the run to MS 28-1 being less than 0.5 km longer that the leg to MS 2.

Based on the expected minimal impact that the total F9 load would have on the F2 losses and the minor changes to the 44,000 V system, no further upstream modeling was considered necessary; impacts were judged to be not material.

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Conclusion

The validation process used to compare actual current measurements on F9 to the results of the model scenarios confirms that the model results are robust. To obtain greater accuracy would require the following:

- measurement and data collection of each individual load on F9;
- identification of transformer tap settings for all distribution transformers on F9;
- identification of distribution transformer characteristics;
- 365 day, hourly load profile for F9;
- identification of all load points on F2;
- measurement and data collection of each individual load on F2;
- transformer characteristics for F2;
- 365 day, hourly load profile for F9;
- similar data as above pertaining to the 44,000 V feeder

For the purposes of this analysis, the models are sufficiently accurate to estimate the loss reduction from a voltage conversion of F9 to 27600 V.

As the charts and analysis illustrate, there are significant line loss savings which would result from voltage conversion to 27,600 V for feeder F9. The range of line loss reduction (3% - 5%) translates into 35 to 105 kW savings. This would impact the demand charges to Lakefront Utilities. Associated with this is the energy savings which amount to 700 – 2000 kWh per day. At an average value of 1,500 kWh per day this translates into 547,000 kWh per year. At the current artificially low price of 4.7 cents/kWh this represents a savings of $25,700 each year.

In addition to the above savings, other, non-monetary benefits arise from a voltage conversion to 27,600 V. One of the supplemental benefits is the improvement in voltage support to the customers. On a feeder the length of F9, there will be no appreciable voltage drop between the supply point and the last customer at line end.

Recommendations

Based on the result of this study, it is recommended that Lakefront Utilities Inc:

- investigates the benefits of voltage conversion of F9 to 27,600 V against system investment required to complete the conversion;
- use this analysis as support for the system optimization aspects of your Conservation and Demand Management Plan;
- consider the analysis contained in this report as the foundation for reporting results to the Ontario Energy Board;
- continue to explore other loss mitigation opportunities, and
- continue to expand the model in this analysis to other portions of the distribution system to uncover other system optimization opportunities.

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Appendix 1 – 4,160 V System Model

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Appendix 2 – 27,600 V System Model

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Appendix 3 – Model October 22, 2004

F9-0 to F9-2	4160V		50%, 50% Scaling 10 deg C			F9-1 to F9-2			27,600 kV		
Hour	R	W	B	Avg		Hour	R	W	B	Avg	
0:00	242	220	226	229	Amps	0:00	33	32	32	32	Amps
1:00	229	209	214	217		1:00	31	30	30	30	
2:00	220	200	205	208		2:00	30	28	29	29	
3:00	211	192	197	200		3:00	29	27	27	28	
4:00	208	189	195	197		4:00	28	27	27	27	
5:00	206	187	192	195		5:00	28	26	27	27	
6:00	210	191	196	199		6:00	28	27	27	27	
7:00	217	197	203	206		7:00	30	28	28	29	
8:00	236	215	221	224		8:00	33	31	31	32	
9:00	256	233	239	243		9:00	36	34	34	35	
10:00	270	246	253	256		10:00	38	36	36	37	
11:00	278	253	260	264		11:00	39	37	37	38	
12:00	277	253	260	263		12:00	39	37	37	38	
13:00	278	253	261	264		13:00	39	37	37	38	
14:00	273	249	257	260		14:00	39	37	37	38	
15:00	273	249	256	259		15:00	39	36	37	37	
16:00	275	251	258	261		16:00	39	37	37	38	
17:00	285	260	267	271		17:00	40	38	38	39	
18:00	285	260	267	271		18:00	40	38	38	39	
19:00	281	257	263	267		19:00	40	38	38	39	
20:00	270	246	253	256		20:00	38	36	36	37	
21:00	264	241	248	251		21:00	37	35	35	36	
22:00	265	242	249	252		22:00	37	35	36	36	
23:00	250	228	234	237		23:00	35	33	33	34	

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F9	4160V incl 44kV/4160V Transf Region Load			kVA Max	Transf Loading	Region Load Losses			Distribution Transformer			
				1,952	39%							
Hour	Real kW	Reactive kVAr	Apparent kVA	pf	Real kW	Reactive kVAr	Apparent kVA	pf	Load Losses kW	No Load Losses kW	Load Losses %	kW
0:00	1258	1076	1,655	0.76	44	95	105	0.42	3	106	3.74%	47
1:00	1176	1039	1,569	0.75	40	85	94	0.43	2	106	3.57%	42
2:00	1121	1003	1,504	0.75	36	78	86	0.42	2	106	3.39%	38
3:00	1071	968	1,444	0.74	33	72	79	0.42	2	106	3.27%	35
4:00	1056	957	1,425	0.74	33	70	77	0.43	2	106	3.31%	35
5:00	1050	939	1,409	0.75	32	69	76	0.42	2	106	3.24%	34
6:00	1090	934	1,435	0.76	33	71	78	0.42	2	106	3.21%	35
7:00	1156	929	1,483	0.78	35	76	84	0.42	2	106	3.20%	37
8:00	1262	1008	1,615	0.78	42	90	99	0.42	3	106	3.57%	45
9:00	1376	1085	1,752	0.79	49	106	117	0.42	3	106	3.78%	52
10:00	1450	1145	1,848	0.78	55	118	130	0.42	4	106	4.07%	59
11:00	1496	1175	1,902	0.79	58	125	138	0.42	4	106	4.14%	62
12:00	1496	1170	1,899	0.79	58	125	138	0.42	4	106	4.14%	62
13:00	1496	1179	1,905	0.79	59	126	139	0.42	4	106	4.21%	63
14:00	1465	1168	1,874	0.78	57	122	135	0.42	4	106	4.16%	61
15:00	1461	1168	1,870	0.78	56	121	133	0.42	4	106	4.11%	60
16:00	1476	1172	1,885	0.78	57	123	136	0.42	4	106	4.13%	61
17:00	1547	1189	1,951	0.79	61	132	145	0.42	5	106	4.27%	66
18:00	1585	1139	1,952	0.81	61	132	145	0.42	5	106	4.16%	66
19:00	1567	1121	1,927	0.81	60	129	142	0.42	4	106	4.08%	64
20:00	1494	1090	1,849	0.81	55	118	130	0.42	4	106	3.95%	59
21:00	1494	1090	1,849	0.81	55	118	130	0.42	4	106	3.95%	59
22:00	1444	1106	1,819	0.79	53	114	126	0.42	4	106	3.95%	57
23:00	1323	1090	1,714	0.77	47	102	112	0.42	3	106	3.78%	50
	32,410				1,169				80		3.85%	1,249

Feeder Voltage Conversion Loss Assessment
Lakefront Utilities Inc.

F9 27,600 V

	Region Load				Region Load Losses				Distribution Transformer			
Hour	Real kW	Reactive kVAr	Apparent kVA	pf	Real kW	Reactive kVAr	Apparent kVA	pf	Load Losses kW	No Load Losses kW	Load Losses %	Load Losses kW
0:00	1251	947	1,569	0.80	0	1	1	0.00	2	56	0.16%	2
1:00	1163	908	1,475	0.79	0	1	1	0.00	2	56	0.17%	2
2:00	1106	870	1,407	0.79	0	1	1	0.00	2	56	0.18%	2
3:00	1052	833	1,342	0.78	0	1	1	0.00	2	56	0.19%	2
4:00	1037	821	1,323	0.78	0	1	1	0.00	2	56	0.19%	2
5:00	1030	802	1,305	0.79	0	1	1	0.00	1	56	0.10%	1
6:00	1073	796	1,336	0.80	0	1	1	0.00	2	56	0.19%	2
7:00	1142	792	1,390	0.82	0	1	1	0.00	2	56	0.18%	2
8:00	1256	877	1,532	0.82	0	1	1	0.00	2	56	0.16%	2
9:00	1377	961	1,679	0.82	1	2	2	0.45	3	56	0.29%	4
10:00	1458	1027	1,783	0.82	1	2	2	0.45	3	56	0.27%	4
11:00	1508	1058	1,842	0.82	1	2	2	0.45	4	56	0.33%	5
12:00	1506	1048	1,835	0.82	1	2	2	0.45	4	56	0.33%	5
13:00	1506	1059	1,841	0.82	1	2	2	0.45	4	56	0.33%	5
14:00	1474	1050	1,810	0.81	1	2	2	0.45	4	56	0.34%	5
15:00	1469	1050	1,806	0.81	1	2	2	0.45	4	56	0.34%	5
16:00	1486	1051	1,820	0.82	1	2	2	0.45	4	56	0.34%	5
17:00	1562	1060	1,888	0.83	1	2	2	0.45	4	56	0.32%	5
18:00	1602	998	1,887	0.85	1	2	2	0.45	4	56	0.31%	5
19:00	1582	986	1,864	0.85	1	2	2	0.45	4	56	0.32%	5
20:00	1502	959	1,782	0.84	1	2	2	0.45	3	56	0.27%	4
21:00	1456	956	1,742	0.84	1	2	2	0.45	3	56	0.27%	4
22:00	1448	979	1,748	0.83	1	2	2	0.45	3	56	0.28%	4
23:00	1320	962	1,633	0.81	0	2	2	0.00	3	56	0.23%	3
	32,366				14				71		0.26%	85

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Appendix 4 – Model December 22, 2004

F9-0 to F9-2	4160V		50%, 65.5% Scaling Actual Temp			F9-1 to F9-2	27,600 kV				
Hour	R	W	B	Avg		Hour	R	W	B	Avg	
0:00	302	275	283	287	Amps	0:00	46	42	43	44	Amps
1:00	285	260	267	271		1:00	44	40	41	42	
2:00	273	249	256	259		2:00	42	38	39	40	
3:00	261	238	245	248		3:00	40	36	37	38	
4:00	258	235	241	245		4:00	39	36	37	37	
5:00	254	232	238	241		5:00	39	35	36	37	
6:00	260	237	243	247		6:00	40	36	37	38	
7:00	269	245	252	255		7:00	41	37	38	39	
8:00	294	268	275	279		8:00	45	41	42	43	
9:00	319	292	300	304		9:00	49	45	46	47	
10:00	337	308	316	320		10:00	52	47	49	49	
11:00	347	317	326	330		11:00	54	49	50	51	
12:00	346	316	326	329		12:00	54	49	50	51	
13:00	347	317	327	330		13:00	54	49	50	51	
14:00	341	312	321	325		14:00	53	48	50	50	
15:00	341	311	320	324		15:00	53	48	50	50	
16:00	343	314	323	327		16:00	53	48	50	50	
17:00	356	326	335	339		17:00	55	50	52	52	
18:00	357	326	335	339		18:00	55	50	52	52	
19:00	352	322	331	335		19:00	54	49	51	51	
20:00	337	308	317	321		20:00	52	47	49	49	
21:00	330	302	310	314		21:00	51	46	48	48	
22:00	332	303	311	315		22:00	51	47	48	49	
23:00	312	285	292	296		23:00	48	44	45	46	

F9 4160V incl 44kV/4160V Transf

kVA Max 2,449

Transf Loading 49%

Hour	Region Load Real kW	Region Load Reactive kVAr	Region Load Apparent kVA	pf	Region Load Losses Real kW	Region Load Losses Reactive kVAr	Region Load Losses Apparent kVA	pf	Distribution Transformer Load Losses kW	Distribution Transformer No Load Losses kW	Total Load Losses %	Total Load Losses kW
0:00	1606	1305	2,069	0.78	69	148	163	0.42	5	106	4.61%	74
1:00	1498	1257	1,956	0.77	62	132	146	0.43	4	106	4.41%	66
2:00	1427	1210	1,871	0.76	56	121	133	0.42	4	106	4.20%	60
3:00	1362	1165	1,792	0.76	52	111	123	0.42	4	106	4.11%	56
4:00	1340	1149	1,765	0.76	50	108	119	0.42	3	106	3.96%	53
5:00	1331	1126	1,743	0.76	49	105	116	0.42	3	106	3.91%	52
6:00	1384	1119	1,780	0.78	51	110	121	0.42	4	106	3.97%	55
7:00	1470	1113	1,844	0.80	55	118	130	0.42	4	106	4.01%	59
8:00	1606	1213	2,013	0.80	65	140	154	0.42	5	106	4.36%	70
9:00	1752	1314	2,190	0.80	77	166	183	0.42	6	106	4.74%	83
10:00	1846	1390	2,311	0.80	86	185	204	0.42	7	106	5.04%	93
11:00	1907	1429	2,383	0.80	92	197	217	0.42	7	106	5.19%	99
12:00	1905	1422	2,377	0.80	91	196	216	0.42	7	106	5.14%	98
13:00	1905	1434	2,384	0.80	92	197	217	0.42	7	106	5.20%	99
14:00	1864	1419	2,343	0.80	89	190	210	0.42	7	106	5.15%	96
15:00	1859	1419	2,339	0.79	88	190	209	0.42	7	106	5.11%	95
16:00	1877	1424	2,356	0.80	90	192	212	0.42	7	106	5.17%	97
17:00	1969	1449	2,445	0.81	96	207	228	0.42	8	106	5.28%	104
18:00	2018	1388	2,449	0.82	97	208	230	0.42	8	106	5.20%	105
19:00	1996	1363	2,417	0.83	94	202	223	0.42	8	106	5.11%	102
20:00	1901	1320	2,314	0.82	86	186	205	0.42	7	106	4.89%	93
21:00	1847	1313	2,266	0.82	83	178	196	0.42	7	106	4.87%	90
22:00	1839	1341	2,276	0.81	83	179	197	0.42	7	106	4.89%	90
23:00	1682	1319	2,137	0.79	74	158	174	0.42	6	106	4.76%	80
	41,191				1,827				142		4.78%	1,969

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Feeder Voltage Conversion Loss Assessment
Lakefront Utilities Inc.

	Region Load				Region Load Losses				Distribution Transformer		Total	
Hour	Real kW	Reactive kVAr	Apparent kVA	pf	Real kW	Reactive kVAr	Apparent kVA	pf	Load Losses kW	No Load Losses kW	Load Losses %	Load Losses kW
0:00	1654	1331	2,123	0.78	1	3	3	0.32	6	106	0.42%	7
1:00	1539	1280	2,002	0.77	1	2	2	0.45	5	106	0.39%	6
2:00	1464	1230	1,912	0.77	1	2	2	0.45	4	106	0.34%	5
3:00	1395	1182	1,828	0.76	1	2	2	0.45	4	106	0.36%	5
4:00	1372	1166	1,801	0.76	1	2	2	0.45	4	106	0.36%	5
5:00	1363	1141	1,778	0.77	1	2	2	0.45	4	106	0.37%	5
6:00	1418	1133	1,815	0.78	1	2	2	0.45	4	106	0.35%	5
7:00	1508	1128	1,883	0.80	1	2	2	0.45	4	106	0.33%	5
8:00	1654	1237	2,065	0.80	1	3	3	0.32	5	106	0.36%	6
9:00	1810	1345	2,255	0.80	1	3	3	0.32	7	106	0.44%	8
10:00	1914	1429	2,389	0.80	2	4	4	0.45	8	106	0.52%	10
11:00	1979	1470	2,465	0.80	2	4	4	0.45	8	106	0.51%	10
12:00	1975	1457	2,454	0.80	2	4	4	0.45	8	106	0.51%	10
13:00	1975	1470	2,462	0.80	2	4	4	0.45	8	106	0.51%	10
14:00	1932	1459	2,421	0.80	2	4	4	0.45	8	106	0.52%	10
15:00	1927	1459	2,417	0.80	2	4	4	0.45	8	106	0.52%	10
16:00	1948	1460	2,434	0.80	2	4	4	0.45	8	106	0.51%	10
17:00	2046	1473	2,521	0.81	2	4	4	0.45	9	106	0.54%	11
18:00	2096	1394	2,517	0.83	2	4	4	0.45	9	106	0.52%	11
19:00	2071	1378	2,488	0.83	2	4	4	0.45	8	106	0.48%	10
20:00	1969	1342	2,383	0.83	2	4	4	0.45	8	106	0.51%	10
21:00	1909	1338	2,331	0.82	1	4	4	0.24	7	106	0.42%	8
22:00	1900	1368	2,341	0.81	2	4	4	0.45	7	106	0.47%	9
23:00	1734	1345	2,194	0.79	1	3	3	0.32	6	106	0.40%	7
	42,552				36				157		0.45%	193

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Appendix 5 – Model 30% Supply Transformer Loading

F9-0 to F9-2	4160V		50%, 35% Scaling 15 deg			F9-1 to F9-2	27,600 kV			
Hour	R	W	B	Avg		Hour	R	W	B	Avg
0:00	185	168	173	175	Amps	0:00	28	25	26	26
1:00	176	160	164	167		1:00	26	24	25	25
2:00	169	154	158	160		2:00	25	23	24	24
3:00	163	148	152	154		3:00	24	22	23	23
4:00	161	146	150	152		4:00	24	22	22	23
5:00	160	145	149	151		5:00	24	22	22	23
6:00	162	147	151	153		6:00	24	22	23	23
7:00	167	151	156	158		7:00	25	23	23	24
8:00	181	164	169	171		8:00	27	25	25	26
9:00	195	177	182	185		9:00	29	27	27	28
10:00	206	187	192	195		10:00	31	28	29	29
11:00	212	192	198	201		11:00	32	29	30	30
12:00	211	192	198	200		12:00	32	29	30	30
13:00	212	193	198	201		13:00	32	29	30	30
14:00	209	190	195	198		14:00	32	29	30	30
15:00	208	189	195	197		15:00	32	29	29	30
16:00	210	191	196	199		16:00	32	29	30	30
17:00	216	197	202	205		17:00	33	30	31	31
18:00	216	196	202	205		18:00	33	30	30	31
19:00	213	194	200	202		19:00	32	29	30	30
20:00	205	187	192	195		20:00	31	28	29	29
21:00	202	183	189	191		21:00	30	28	28	29
22:00	202	183	188	191		22:00	30	28	28	29
23:00	191	174	178	181		23:00	29	26	27	27

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			kVA Max	Transf Loading
F9	4160V incl 44kV/4160V Transf		1,482	30%

	Region Load				Region Load Losses				Distribution Transformer		Total	
Hour	Real kW	Reactive kVAr	Apparent kVA	pf	Real kW	Reactive kVAr	Apparent kVA	pf	Load Losses kW	No Load Losses kW	Load Losses %	Load Losses kW
0:00	930	859	1,266	0.73	26	55	61	0.43	1	106	2.90%	27
1:00	871	832	1,205	0.72	23	50	55	0.42	1	106	2.76%	24
2:00	831	806	1,158	0.72	21	46	51	0.42	1	106	2.65%	22
3:00	796	781	1,115	0.71	20	43	47	0.42	1	106	2.64%	21
4:00	785	773	1,102	0.71	19	42	46	0.41	1	106	2.55%	20
5:00	781	761	1,090	0.72	19	41	45	0.42	1	106	2.56%	20
6:00	810	757	1,109	0.73	20	42	47	0.43	1	106	2.59%	21
7:00	857	753	1,141	0.75	21	45	50	0.42	1	106	2.57%	22
8:00	933	810	1,236	0.76	24	53	58	0.41	1	106	2.68%	25
9:00	1015	866	1,334	0.76	28	62	68	0.41	1	106	2.86%	29
10:00	1073	912	1,408	0.76	32	69	76	0.42	2	106	3.17%	34
11:00	1108	934	1,449	0.76	34	73	81	0.42	2	106	3.25%	36
12:00	1108	930	1,447	0.77	34	72	80	0.43	2	106	3.25%	36
13:00	1108	936	1,450	0.76	34	73	81	0.42	2	106	3.25%	36
14:00	1086	929	1,429	0.76	33	71	78	0.42	2	106	3.22%	35
15:00	1082	929	1,426	0.76	33	70	77	0.43	2	106	3.23%	35
16:00	1093	931	1,436	0.76	33	71	78	0.42	2	106	3.20%	35
17:00	1144	942	1,482	0.77	35	76	84	0.42	2	106	3.23%	37
18:00	1170	904	1,479	0.79	35	76	84	0.42	2	106	3.16%	37
19:00	1157	893	1,462	0.79	34	74	81	0.42	2	106	3.11%	36
20:00	1104	871	1,406	0.79	32	68	75	0.43	2	106	3.08%	34
21:00	1073	868	1,380	0.78	31	66	73	0.43	2	106	3.08%	33
22:00	1063	881	1,381	0.77	31	66	73	0.43	2	106	3.10%	33
23:00	977	869	1,308	0.75	27	59	65	0.42	1	106	2.87%	28
	23,955				679				37		2.99%	716

Feeder Voltage Conversion Loss Assessment
Lakefront Utilities Inc.

	Region Load				Region Load Losses				Distribution Transformer		Total	
Hour	Real kW	Reactive kVAr	Apparent kVA	pf	Real kW	Reactive kVAr	Apparent kVA	pf	Load Losses kW	No Load Losses kW	Load Losses %	Load Losses kW
0:00	945	865	1,281	0.74	0	1	1	0.00	1	106	0.11%	1
1:00	884	838	1,218	0.73	0	1	1	0.00	1	106	0.11%	1
2:00	843	811	1,170	0.72	0	1	1	0.00	1	106	0.12%	1
3:00	806	785	1,125	0.72	0	0	-	#DIV/0!	1	106	0.12%	1
4:00	795	777	1,112	0.72	0	0	-	#DIV/0!	1	106	0.13%	1
5:00	791	764	1,100	0.72	0	0	-	#DIV/0!	1	106	0.13%	1
6:00	821	759	1,118	0.73	0	0	-	#DIV/0!	1	106	0.12%	1
7:00	869	757	1,152	0.75	0	0	-	#DIV/0!	1	106	0.12%	1
8:00	949	817	1,252	0.76	0	1	1	0.00	1	106	0.11%	1
9:00	1034	875	1,355	0.76	0	1	1	0.00	2	106	0.19%	2
10:00	1095	924	1,433	0.76	0	1	1	0.00	2	106	0.18%	2
11:00	1131	946	1,474	0.77	0	1	1	0.00	2	106	0.18%	2
12:00	1130	940	1,470	0.77	0	1	1	0.00	2	106	0.18%	2
13:00	1130	947	1,474	0.77	0	1	1	0.00	2	106	0.18%	2
14:00	1108	942	1,454	0.76	0	1	1	0.00	2	106	0.18%	2
15:00	1104	941	1,451	0.76	0	1	1	0.00	2	106	0.18%	2
16:00	1116	942	1,460	0.76	0	1	1	0.00	2	106	0.18%	2
17:00	1169	948	1,505	0.78	0	1	1	0.00	2	106	0.17%	2
18:00	1196	905	1,500	0.80	0	1	1	0.00	2	106	0.17%	2
19:00	1181	896	1,482	0.80	0	1	1	0.00	2	106	0.17%	2
20:00	1126	877	1,427	0.79	0	1	1	0.00	2	106	0.18%	2
21:00	1093	875	1,400	0.78	0	1	1	0.00	2	106	0.18%	2
22:00	1083	888	1,401	0.77	0	1	1	0.00	2	106	0.18%	2
23:00	993	876	1,324	0.75	0	1	1	0.00	1	106	0.10%	1
	24,392				-				38		0.16%	38

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Appendix 6 – Model 59% Supply Transformer Loading

F9-0 to F9-2	4160V		50%, 80% Scaling 15 deg			F9-1 to F9-2	27,600 kV				
Hour	R	W	B	Avg	Amps	Hour	R	W	B	Avg	Amps
0:00	361	329	339	343		0:00	56	51	52	53	
1:00	341	311	320	324		1:00	53	48	49	50	
2:00	326	297	306	310		2:00	50	46	47	48	
3:00	312	284	293	296		3:00	48	43	45	45	
4:00	308	281	289	293		4:00	47	43	44	45	
5:00	304	277	286	289		5:00	47	42	44	44	
6:00	311	283	292	295		6:00	48	43	45	45	
7:00	322	294	303	306		7:00	49	45	46	47	
8:00	352	321	331	335		8:00	54	49	51	51	
9:00	383	350	360	364		9:00	60	54	56	57	
10:00	406	371	382	386		10:00	63	58	60	60	
11:00	419	383	395	399		11:00	66	60	62	63	
12:00	419	382	394	398		12:00	65	59	61	62	
13:00	420	384	396	400		13:00	66	60	62	63	
14:00	412	377	389	393		14:00	64	59	61	61	
15:00	412	376	388	392		15:00	64	58	61	61	
16:00	415	379	391	395		16:00	65	59	61	62	
17:00	431	394	406	410		17:00	67	61	63	64	
18:00	432	395	407	411		18:00	67	61	63	64	
19:00	426	390	401	406		19:00	66	60	62	63	
20:00	408	373	384	388		20:00	63	58	60	60	
21:00	399	365	376	380		21:00	62	56	58	59	
22:00	399	365	375	380		22:00	62	56	58	59	
23:00	374	342	352	356		23:00	58	53	54	55	

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			kVA Max	Transf Loading
F9	4160V incl 44kV/4160V Transf		2,967	59%

	Region Load				Region Load Losses				Distribution Transformer		Total	
Hour	Real kW	Reactive kVAr	Apparent kVA	pf	Real kW	Reactive kVAr	Apparent kVA	pf	Load Losses kW	No Load Losses kW	Load Losses %	Load Losses kW
0:00	1946	1528	2,474	0.79	99	212	234	0.42	8	106	5.50%	107
1:00	1816	1471	2,337	0.78	88	189	208	0.42	7	106	5.23%	95
2:00	1730	1413	2,234	0.77	81	173	191	0.42	6	106	5.03%	87
3:00	1651	1358	2,138	0.77	74	159	175	0.42	6	106	4.85%	80
4:00	1628	1341	2,109	0.77	72	154	170	0.42	5	106	4.73%	77
5:00	1619	1314	2,085	0.78	70	151	166	0.42	5	106	4.63%	75
6:00	1683	1306	2,130	0.79	73	158	174	0.42	6	106	4.69%	79
7:00	1789	1298	2,210	0.81	79	169	187	0.42	6	106	4.75%	85
8:00	1954	1420	2,415	0.81	94	202	223	0.42	8	106	5.22%	102
9:00	2130	1541	2,629	0.81	112	240	265	0.42	9	106	5.68%	121
10:00	2255	1639	2,788	0.81	126	269	297	0.42	11	106	6.08%	137
11:00	2330	1687	2,877	0.81	134	287	317	0.42	12	106	6.27%	146
12:00	2330	1682	2,874	0.81	134	287	317	0.42	12	106	6.27%	146
13:00	2331	1697	2,883	0.81	135	289	319	0.42	12	106	6.31%	147
14:00	2282	1677	2,832	0.81	130	279	308	0.42	11	106	6.18%	141
15:00	2275	1678	2,827	0.80	129	277	306	0.42	11	106	6.15%	140
16:00	2297	1684	2,848	0.81	131	282	311	0.42	11	106	6.18%	142
17:00	2407	1719	2,958	0.81	142	303	335	0.42	12	106	6.40%	154
18:00	2467	1648	2,967	0.83	142	305	336	0.42	13	106	6.28%	155
19:00	2441	1615	2,927	0.83	138	297	327	0.42	12	106	6.15%	150
20:00	2326	1561	2,801	0.83	127	272	300	0.42	11	106	5.93%	138
21:00	2260	1552	2,742	0.82	122	261	288	0.42	10	106	5.84%	132
22:00	2239	1578	2,739	0.82	121	260	287	0.42	10	106	5.85%	131
23:00	2048	1551	2,569	0.80	107	229	253	0.42	9	106	5.66%	116
	50,234				2,660				223		5.74%	2,883

Feeder Voltage Conversion Loss Assessment
Lakefront Utilities Inc.

	Region Load				Region Load Losses				Distribution Transformer		Total	
Hour	Real kW	Reactive kVAr	Apparent kVA	pf	Real kW	Reactive kVAr	Apparent kVA	pf	Load Losses kW	No Load Losses kW	Load Losses %	Load Losses kW
0:00	2018	1567	2,555	0.79	2	4	4	0.45	9	106	0.55%	11
1:00	1878	1504	2,406	0.78	2	4	4	0.45	8	106	0.53%	10
2:00	1786	1443	2,296	0.78	1	3	3	0.32	7	106	0.45%	8
3:00	1701	1385	2,194	0.78	1	3	3	0.32	6	106	0.41%	7
4:00	1676	1367	2,163	0.77	1	3	3	0.32	6	106	0.42%	7
5:00	1667	1337	2,137	0.78	1	3	3	0.32	6	106	0.42%	7
6:00	1734	1327	2,184	0.79	1	3	3	0.32	6	106	0.40%	7
7:00	1844	1321	2,268	0.81	1	3	3	0.32	7	106	0.43%	8
8:00	2026	1456	2,495	0.81	2	4	4	0.45	8	106	0.49%	10
9:00	2218	1588	2,728	0.81	2	5	5	0.37	10	106	0.54%	12
10:00	2357	1698	2,905	0.81	3	6	7	0.45	12	106	0.64%	15
11:00	2438	1749	3,000	0.81	3	6	7	0.45	13	106	0.66%	16
12:00	2437	1735	2,992	0.81	3	6	7	0.45	13	106	0.66%	16
13:00	2437	1751	3,001	0.81	3	6	7	0.45	13	106	0.66%	16
14:00	2385	1738	2,951	0.81	3	6	7	0.45	13	106	0.67%	16
15:00	2377	1737	2,944	0.81	3	6	7	0.45	12	106	0.63%	15
16:00	2404	1739	2,967	0.81	3	6	7	0.45	13	106	0.67%	16
17:00	2523	1756	3,074	0.82	3	7	8	0.39	14	106	0.67%	17
18:00	2585	1660	3,072	0.84	3	7	8	0.39	14	106	0.66%	17
19:00	2553	1639	3,034	0.84	3	6	7	0.45	13	106	0.63%	16
20:00	2427	1594	2,904	0.84	3	6	7	0.45	12	106	0.62%	15
21:00	2353	1588	2,839	0.83	2	6	6	0.32	11	106	0.55%	13
22:00	2329	1619	2,836	0.82	2	6	6	0.32	11	106	0.56%	13
23:00	2127	1591	2,656	0.80	2	5	5	0.37	10	106	0.56%	12
	52,280				53				247		0.57%	300

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Appendix 7 – Measured Currents December 22, 2004

Hour	R	W	B	Avg
22/12/2004 0:00	284	240	272	265
22/12/2004 1:00	262	225	256	248
22/12/2004 2:00	255	215	241	237
22/12/2004 3:00	254	216	245	238
22/12/2004 4:00	250	214	248	237
22/12/2004 5:00	251	215	241	236
22/12/2004 6:00	278	225	257	253
22/12/2004 7:00	287	237	278	267
22/12/2004 8:00	300	242	297	280
22/12/2004 9:00	333	273	322	309
22/12/2004 10:00	323	287	321	310
22/12/2004 11:00	332	278	319	310
22/12/2004 12:00	345	285	333	321
22/12/2004 13:00	335	280	336	317
22/12/2004 14:00	337	283	334	318
22/12/2004 15:00	328	278	321	309
22/12/2004 16:00	351	291	330	324
22/12/2004 17:00	375	317	377	356
22/12/2004 18:00	378	330	376	361
22/12/2004 19:00	375	300	362	346
22/12/2004 20:00	342	292	353	329
22/12/2004 21:00	346	288	346	327
22/12/2004 22:00	338	270	315	308
22/12/2004 23:00	290	254	282	275

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OVERVIEW OF OPERATING REVENUE

This Exhibit provides the details of Lakefront Utilities Inc.'s operating revenue for 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, the 2011 Bridge Year and the 2012 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.

Lakefront Utilities Inc. is proposing a total Service Revenue Requirement of $ 5,131,204 for the 2012 Test Year. This amount includes a Base Revenue Requirement of $ 4,752,741 plus revenue offsets of $ 378,462 to be recovered through Other Distribution Revenue.

A summary of all operating revenue is presented below in Table 3-0 and provides a comparison of total revenues from the 2008 OEB approved year to the 2012 Test Year.

Table 3-0 Other Operating Revenue

Summary of Operating Revenue Table	2008 Board Approved	2008 Actual	Variance from 2008 Board Approved	2009 Actual	Variance from 2008 Actual	2010 Actual	Variance from 2009 Actual	2011 Bridge	Variance from 2010 Actual	2012 Test	Variance from 2011 Bridge
	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)
Distribution Revenue											
Residential	1,917,386	1,840,952	(76,434)	1,970,658	129,707	1,909,334	(61,324)	1,913,288	3,954	2,556,790	643,502
GS < 50 kW	656,516	619,069	(37,447)	619,738	670	599,095	(20,644)	571,656	(27,438)	725,309	153,653
GS > 50 - 2999 kW	1,208,240	1,163,463	(44,777)	1,233,761	70,298	1,279,944	46,182	1,194,993	(84,951)	1,181,345	(13,649)
GS > 3000 - 4999 kW	97,123	23,437	(73,686)	62,334	38,897	46,650	(15,684)	41,451	(5,199)	61,414	19,963
Streetlight	73,925	36,635	(37,290)	81,308	44,673	138,517	57,209	208,549	70,032	178,720	(29,829)
Sentinel Light	3,327	2,537	(790)	3,944	1,407	4,489	546	5,518	1,029	5,072	(446)
Unmetered Scattered Load	28,729	31,905	3,176	33,981	2,076	32,830	(1,151)	31,331	(1,499)	44,091	12,760
Total	3,985,246	3,717,998	(267,248)	4,005,725	287,728	4,010,859	5,134	3,966,786	(44,073)	4,752,742	785,956
Other Distribution Revenue											
Specific Service Charges	103,267	133,125	29,858	144,453	11,328	127,499	(16,954)	127,000	(499)	126,500	(500)
Late Payment Charges	27,565	72,437	44,872	61,033	(11,404)	63,140	2,107	63,140	-	63,140	-
Other Distribution Revenue	149,461	158,868	9,407	166,728	7,859	157,273	(9,455)	160,406	3,133	160,322	(84)
Other Income and Expenses	55,271	821,667	766,396	108,311	(713,356)	60,931	(47,380)	28,500	(32,431)	28,500	-
Total	335,564	1,186,098	850,534	480,525	(705,573)	408,843	(71,682)	379,046	(29,797)	378,462	(584)
Grand Total:	4,320,810	4,904,096	583,286	4,486,250	(417,845)	4,419,702	(66,548)	4,345,832	(73,870)	5,131,204	785,371

WEATHER NORMALIZATION METHODOLOGY

The purpose of weather normalization is to predict future customer consumption based on normal weather conditions. To achieve this goal, the relationship between weather change and customer consumption must be defined. LUI reviewed the various processes used by earlier Cost of Service applicants and is proposing to adopt a weather normalization methodology using Multifactor Regression (MR) for weather normalization and customer numbers for its load forecast. LUI is proposing to adopt a weather normalization forecasting method similar to the one approved by the Board in a number of cost of service rate applications over the past three years.

In summary, LUI has used the regression analysis methodology to determine a prediction model. With regards to the overall process of load forecasting, it is LUI's view that conducting a regression analysis on historical purchases to produce an equation that will predict energy purchases is appropriate. LUI knows by month the exact number of kWhs purchased from the IESO for use by customers of LUI. 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 result of the regression analysis produces an equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for LUI for the bridge and test year, which is converted to Billed kWh by rate class. A detail explanation of the process is provided later in this Exhibit.

During the review process of recent cost of service applications, Intervenors expressed concerns with the load forecasting weather normalization process being proposed by LUI. Intervenors suggested the weather normalization should be conducted on an individual rate

class basis and the regression analysis on an individual rate class basis. LUI prepared its purchases and billed energy on the monthly consumed basis, in which purchases are recorded on the basis of actual meter data in the month. However, based on the low R square values, LUI concluded using the equation resulting from the individual rate class regression analysis would not be satisfactory for forecasting purposes. Therefore LUI used the power purchased model to perform regression analysis.

The accuracy will improve when smart meters are fully deployed and actual monthly consumption by rate class and individual customer can be determined. In addition, LUI does not have as many years of monthly historical billed data by rate class as it does for the kWh purchased. As a result, conducting the regression analysis on purchases provides better results since a higher level of historical data increases the accuracy of the regression analysis.

LUI understands that to a certain degree the process of developing a load forecast for a cost of service rate application is an evolving science for electricity distributors in the province. LUI expects to include additional improvements to the load forecasting methodology in future cost of service rate applications by taking into consideration data provided by smart meters and the experience of others conducting load forecasts in future cost of service rate applications.

LUI removed data for 2 (two) specific customers from the analysis due to their negative impacts on the results of the regression analysis. One customer is in the GS>50-2999kW customer class and the other customer is in the GS > 3000-4999 customer class. After running the regression analysis, LUI added back the original data for the GS > 50 -2999 kW customer, in order to better predict 2011 & 2012 data. This GS > 50 -2999 customer usage ranges from 561,500 – 1,162,000 kWh per month. This large variation caused a negative impact on the regression analysis. LUI used industry knowledge and experience with the GS 3000-4999 kW class customer in order to forecast the data for 2011 & 2012 as follows. The average of the usage for 2009 and 2010 was used to forecast the 2011 and 2012 kWh and kW for the customer in the GS 3000-4999 class. The reason LUI determined that removing the GS> 3000-4999 customer was

necessary to provide accuracy, is due to that customer being a major customer, here forth referred to as" un-named customer", who has shut down due to economic downturn. Un-named customer was phased out during 2008-2010. We now have just one customer in the GS 3000-4999 customer class and expect no change in this class. Had we included the un-named customer in our regression analysis, this would have skewed the regression, as it would have included consumption, and dollars related to a customer that no longer exists, nor is expected to be replaced. That customer's space has been partially taken over by smaller customers, that would be allocated to the GS> 50-2999 customer class in the regression data. Again, note that the Un-named customer, as was discussed in Load Forecasting above, has been removed from all data to prevent misrepresentation.

The following Exhibit provides the material to support the weather normalized load forecast used by LUI in this application. Tables 3-1, 3-2 and 3-3 below provide a summary of the weather normalized load and customer/connection forecast used in this section.

Table 3-1 Summary of Load and Customer/Connection Forecast

Table 3-1
Summary of Load and
Customer/Connection Forecast

Year	Billed (kWh)	Growth (kwh)	Percentage Change %	Customer/ Connection Count	Growth	Percentage Change %
2004	250,404,235			11,311		
2005	245,534,411	-4,869,824	-1.94%	11,450	139	1.23%
2006	249,730,055	4,195,644	1.71%	11,707	257	2.24%
2007	251,838,780	2,108,725	0.84%	11,861	154	1.32%
2008	249,119,680	-2,719,100	-1.08%	12,063	202	1.71%
2009	243,045,006	-6,074,674	-2.44%	12,305	241	2.00%
2010	248,087,251	5,042,246	2.07%	12,390	85	0.69%
2011	248,226,168	138,917	0.06%	12,577	187	1.51%
2012	250,200,674	1,974,506	0.80%	12,767	190	1.51%

The years 2004 to 2010 are weather actual, 2011 and 2012 are weather normalized and adjusted by a CDM factor. LUI currently does not have a process to 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 are annual averages and street light, and sentinel lights, are measured as connections.

On a rate class basis actual and forecasted billed amount and number of customers are shown in Table 3-2 and customer usage is shown in Table 3-3.

Table 3-2 Billed Energy and Number of Customers by Rate Class & Number of Customers /Connections

Table 3-2

Billed Energy and Number of Customers by Rate Class

Year	Residential	General Service < 50kW	General Service 50 - 2999 kW	General Service 3000 - 4999 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
Energy (kWh)								
2004	71,606,528	31,362,518	119,715,730	25,202,991	1,904,781	71,663	540,024	250,404,235
2005	72,668,912	31,761,066	118,356,603	20,215,158	1,913,253	70,344	549,075	245,534,411
2006	70,342,664	32,373,170	120,975,702	23,443,190	1,923,811	76,087	595,431	249,730,055
2007	72,101,355	34,122,931	122,417,181	20,583,615	1,931,928	76,442	605,328	251,838,780
2008	72,186,004	34,456,796	121,003,376	18,805,505	1,867,000	81,012	719,986	249,119,680
2009	71,936,998	34,498,946	114,875,960	19,554,367	1,350,902	79,959	747,874	243,045,006
2010	72,645,801	34,124,597	120,290,733	19,036,344	1,194,280	78,873	716,623	248,087,251
2011	72,459,122	34,436,304	120,035,230	19,295,356	1,204,881	78,652	716,623	248,226,168
2012	73,125,152	35,160,634	120,608,902	19,295,356	1,215,575	78,431	716,623	250,200,674

Number of Customers/Connections

Year	Residential	General Service < 50kW	General Service 50 - 2999 kW	General Service 3000 - 4999 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
2004	7,472	968	146	1	2,612	55	58	11,311
2005	7,539	1,010	146	1	2,641	55	58	11,450
2006	7,717	1,041	141	1	2,678	59	70	11,707
2007	7,835	1,044	133	1	2,710	58	81	11,861
2008	7,942	1,044	133	1	2,793	57	94	12,063
2009	8,196	1,061	130	1	2,770	53	95	12,305
2010	8,305	1,067	132	1	2,755	54	77	12,390
2011	8,453	1,084	129	1	2,779	54	77	12,577
2012	8,603	1,102	127	1	2,804	54	77	12,767

Table 3-3 Annual kWh Usage per Customer/Connection & Growth Rate

Table 3-3
Annual kWh Usage per Customer/Connection

Year	Residential	General Service < 50kW	General Service 50 - 2999 kW	General Service 3000 - 4999 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
2004	9,584	32,416	822,318	25,202,991	729	1,305	9,311
2005	9,639	31,462	809,737	20,215,158	724	1,279	9,467
2006	9,115	31,088	858,491	23,443,190	718	1,301	8,486
2007	9,203	32,695	917,555	20,583,615	713	1,312	7,520
2008	9,089	33,010	911,513	18,805,505	668	1,430	7,639
2009	8,778	32,521	885,364	19,554,367	488	1,509	7,886
2010	8,747	31,992	914,758	19,036,344	434	1,461	9,337
2011	8,615	31,922	931,146	19,295,356	434	1,461	9,337
2012	8,485	31,852	947,826	19,295,356	434	1,461	9,337

Annual Growth Rate in kWh Usage per Customer/Connection

Year	Residential	General Service < 50kW	General Service 50 - 2999 kW	General Service 3000 - 4999 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
2004							
2005	1.0057	0.9706	0.9847	0.0000	0.9936	0.9801	1.0168
2006	0.9457	0.9881	1.0602	0.0000	0.9917	1.0169	0.8964
2007	1.0096	1.0517	1.0688	0.0000	0.9924	1.0090	0.8861
2008	0.9877	1.0096	0.9934	0.0000	0.9375	1.0894	1.0159
2009	0.9657	0.9852	0.9713	0.0000	0.7297	1.0553	1.0323
2010	0.9965	0.9837	1.0332	0.0000	0.8889	0.9681	1.1840
2011 Normalized	0.9849	0.9978	1.0179	0.0000	1.0000	1.0000	1.0000
2012 Normalized	0.9849	0.9978	1.0179	0.0000	1.0000	1.0000	1.0000

Note that the Table 3-3 Annual Growth Rate in kWh Usage per Customer/Connection presents Streetlights, Sentinel Lights, and USL with an annual growth rate in usage/customer or connection as a 1.0 growth rate. This is based on both trending in our distribution area, as well as industry and local growth knowledge.

LOAD FORECAST & METHODOLOGY

LUI'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, economic and other variables

described below. Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Finally, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression model.

The forecast of customers by rate class is determined using a geometric mean analysis. For those rate classes that use kW for the distribution volumetric billing a geometric mean analysis was also used to calculate the future kW.

The following explains the forecasting process in more detail.

Purchased kWh Load Forecast

An equation to predict total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (heating and cooling degree days), economic output (GDP growth), calendar variables (days in month, seasonal), and monthly peak hours. The regression model uses monthly kWh and monthly values of independent variables from January 2004 to December 2010 to determine the monthly regression coefficients.

Data for LUI's total system load beginning in January 2004 was used. This provides a reasonable data set for use in a multiple regression analysis. Based on the recent global activity surrounding climate change, historical weather data is showing that there is a warming of the global climate system. In this regard, it is LUI's view it is appropriate to review the impact of weather since 2004 on the energy usage, and then determine the average weather conditions

from January 2004 to December 2010, which would be applied in the forecasting process to determine a weather normalized forecast.

In accordance with the filing requirement LUI has also provided a comparison of the average of heating and cooling days used in this application, 10 and 20 year trend of data in Table 3-4. LUI has provided the load forecasts based on a 10-year and 20-year trend Heating Degree Days and Cooling Degree Days.

Table 3-4 10 and 20 Year Trend

Table 3-4 **Summary of Degree Day Information** **Source of Data: Cobourg Weather Station**

Summary of All Heating Degree Days

Month	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Model	7 Year Avg	10 Year Avg	20 Year Trend
January	714.6	703.9	676.3	921.8	640.2	761.8	739	639.3	738.5	678.5	657.4	573.8	832.6	872.6	782.8	589	669.3	633.3	823.9	718	706.18	726.99	715.27	711.32
February	568	622.3	736.7	723.7	566.4	669.3	582.8	520.7	551.8	577	601	547.4	713.4	636.4	631.3	627.2	728.2	660.6	608.5	597.2	642.05	641.34	635.12	631.39
March	516.6	620.9	606.8	572.6	143.9	625.5	601.6	518.8	576.5	473.9	581.1	474.8	592.2	519.9	612.1	564.4	578.3	632.3	568.1	450.7	566.68	560.83	557.39	562.38
April	311	379.2	357.8	361.5	433.6	415.6	389.4	323.6	335.6	377.8	335.8	354	435.4	372.3	362.5	342.6	401	326.3	345.4	262.7	340.74	344.69	353.80	339.73
May	132.3	192.6	199.5	241.1	200	252.7	290	78.8	136.1	193.7	158.2	261.9	207.7	205.4	259.9	192.1	208.1	253.6	231.1	160.4	217.29	215.80	213.84	219.56
June	25.1	75.9	72.5	58.3	30.8	38.7	33.3	68.3	36.1	73.5	51.1	57.8	65.4	100.8	40.7	40.1	45.4	71	86.1	37.9	54.50	60.29	59.63	62.77
July	1.2	26.6	2.2	2.5	13.9	12.9	24.6	4.6	4.4	16.9	28	5	11.9	14.7	4.2	5.9	22.4	9.4	41.5	5.1	14.75	14.74	14.81	17.29
August	1	41.7	9.4	32.9	8.6	3.1	17.1	5.2	14.9	25.7	3	3	9.7	26.9	1	6.7	12.1	15.2	15.7	6	9.81	11.94	9.93	8.30
September	115.9	112.1	124	77.5	129	65.5	105.7	56.3	56.7	124	80.9	35.8	59.9	50.3	45.5	103.3	61.8	73.5	70.1	99.9	75.17	72.06	68.10	57.16
October	241.2	337.1	309.9	279.9	232.7	275.3	293.7	247.6	269.1	254.1	263.8	295.9	325.6	250.1	251.9	296.4	165.8	288.1	313.3	265.5	263.23	261.59	271.64	263.44
November	437.4	424.8	441.2	373.3	499.1	513	457.6	419.1	385.3	432.2	368.5	446.6	420.5	411	411.5	390.9	441.5	459	361	412.1	412.63	412.43	412.26	401.81
December	629.1	621.5	613.9	578.8	717.6	539	578.6	566.4	586.6	769.6	521.1	617.4	606.4	645.2	668.4	505.5	648.3	652.5	638.6	676.5	631.91	633.57	617.99	636.48
Total	3,693.40	4,158.60	4,150.20	4,223.90	3,615.80	4,172.40	4,113.40	3,448.70	3,691.60	3,996.90	3,649.90	3,673.40	4,280.70	4,105.60	4,071.80	3,664.10	3,982.20	4,074.80	4,103.30	3,692.00	3,934.92	3,956.26	3,929.78	3,911.62

Summary of All Cooling Degree Days

Month	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Model	7 Year Avg	10 Year Avg	20 Year Trend
January	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00	0.00
February	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00	0.00
March	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00	0.00
April	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00	0.00
May	10.1	0	0.5	0	0	0	0	4	1.8	0	0	2.3	0	0	0	6.3	1.9	0	0	9.1	2.82	2.88	1.96	2.22
June	33	4.8	9.5	31.1	58.7	18.1	27.6	35.6	46.8	5.4	30.8	24.3	12.1	5.1	52.6	18	19.9	2.6	17.4	15.7	20.71	21.03	19.85	16.38
July	87.1	16.5	86.5	63.8	92.1	35	58.3	58.5	110.5	30.5	46.6	91.2	37.8	41.2	116.8	86.9	45.3	50.9	18.2	90.2	67.50	68.05	62.51	60.84
August	83.9	18.2	86.5	36.4	106.5	61.8	24	64	51	49.6	83.8	85.8	88.1	43.1	87.6	56.4	91.5	40.4	58.6	80.7	68.67	69.20	71.60	71.16
September	26.9	15.5	8.4	5.9	5.5	26.3	1.6	14.3	36.3	15.6	16.9	38.8	14.6	18.1	16.3	1.3	17.9	16.2	11.6	14.4	13.06	12.95	16.61	15.76
October	0	0	0	0	0	0	0	0	0	0	0.3	4	0	0	0	0	4.1	0	0	0	0.67	0.68	0.84	0.99
November	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00	0.00
December	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00	0.00
Total	241.00	55.00	191.40	137.20	262.80	141.20	111.50	176.40	246.40	101.10	178.40	246.40	152.60	107.50	273.30	168.90	180.60	110.10	105.80	210.10	173.43	174.80	173.37	167.36

The multifactor regression model has determined that the drivers of year-over-year changes in LUI's load growth are economic growth, weather, calendar factors, and monthly peak hours. These factors are captured within the multifactor regression model.

Economic growth – which encompasses trends in the LUI service area, as well as general economic conditions, are captured in the model using an index of economic output, Ontario Real Gross Domestic Product ("GDP") and historical customer numbers.

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.

Additional factors determining energy use in the monthly model can be classified as calendar factors. For example, the number of days in a particular month will impact energy use. The modeling of purchased energy uses number of days in the month and a "flag" variable to capture the typically lower usage in the spring and fall months.

Monthly peak hours were also used as predictors of usage.

The following historical monthly data were used as inputs in the regression model:

- Monthly total system purchased energy data from January 2004 to December 2010;
- Weather data: heating degree-days (HDD) and cooling degree-days (CDD) (LUI uses the degree-days count for the Cobourg data point as published by Environment Canada);
- Real gross domestic product (GDP) for Ontario (2004 to 2006: 2003 and 2008 Ontario Economic Outlook and Fiscal Review, Ontario Ministry of Finance, 2007 to 2011: 2010 Ontario Budget March 25, 2010, Ontario Ministry of Finance);
- Number of days in the month;
- Number of peak hours (16* number of business days in any given month, excluding weekends and holidays)
- Spring fall flag (1 for Spring and Fall, and 0 for Summer and Winter)

The prediction formula has the following statistical results in Table 3-5, which indicates the formula has a very good fit to the actual data set.

Table 3-5 Statistical Results

Table 3-5
Statistical Results

	Value
R Square	91%
Adjusted R Square	90%
T-Stats by Coefficient	
Intercept	-1.95
Heating Degree Days	19.86
Cooling Degree Days	8.77
Ontario Real GDP Monthly %	4.09
Number of Days in Month	5.01
Spring Fall Flag	-6.33
Number of Peak Hours	2.61

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix A.

The annual results of the above prediction formula compared to the actual annual purchases from 2004 to 2010 are shown in Table 3-6 below. In addition, the predicted total system purchases for LUI are provided for the years 2011 and 2012. For 2011 and 2012, the system purchases reflect a weather normalized forecast for the full year.

Table 3-6 Actual vs. Predicted Purchases

Table 3-6

Actual vs. Predicted Purchases (kWh)

Year	Actual	Predicted	% Difference
2004	264,365,121	263,973,437	-0.1%
2005	265,103,480	265,303,309	0.1%
2006	265,431,760	265,079,882	-0.1%
2007	267,650,333	266,595,213	-0.4%
2008	261,227,184	261,564,711	0.1%
2009	257,221,767	259,497,349	0.9%
2010	261,542,031	260,527,776	-0.4%
2011		262,257,591	
2012		264,343,709	

Billed kWh Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by a loss factor. LUI has applied the Total Loss Factor applied for in this application as detailed in Exhibit 8.

Billed kWh Load Forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed energy amount is known, this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available as shown in Table 3-7.

Table 3-7 Number of Customers/Connections

Table 3-7
Number of Customers/Connections

Year	Residential	General Service < 50kW	General Service 50 - 2999 kW	General Service 3000 - 4999 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
2004	7,472	968	146	1	2,612	55	58	11,311
2005	7,539	1,010	146	1	2,641	55	58	11,450
2006	7,717	1,041	141	1	2,678	59	70	11,707
2007	7,835	1,044	133	1	2,710	58	81	11,861
2008	7,942	1,044	133	1	2,793	57	94	12,063
2009	8,196	1,061	130	1	2,770	53	95	12,305
2010	8,305	1,067	132	1	2,755	54	77	12,390

From the historical customer/connection data the growth rate in customer/connection can be evaluated which is provided in Table 3-8. The geometric mean growth rate in number of customers is also provided for 2011 and 2012. The geometric mean approach provides the average growth rate on a compounding basis.

Table 3-8 Growth Rate in Customers/ Connections

Table 3-8
Growth Rate in Customers/Connections

Year	Residential	General Service < 50kW	General Service 50 - 2999 kW	General Service 3000 - 4999 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
2004							
2005	1.0090	1.0434	1.0040	0.0000	1.0109	1.0015	1.0000
2006	1.0236	1.0315	0.9641	0.0000	1.0139	1.0636	1.2098
2007	1.0152	1.0022	0.9468	0.0000	1.0119	0.9957	1.1473
2008	1.0137	1.0002	0.9950	0.0000	1.0308	0.9728	1.1708
2009	1.0320	1.0163	0.9774	0.0000	0.9916	0.9353	1.0062
2010	1.0134	1.0055	1.0135	0.0000	0.9946	1.0189	0.8093
2011 Normalized	1.0178	1.0164	0.9832	0.0000	1.0089	0.9972	1.0000
2012 Normalized	1.0178	1.0164	0.9832	0.0000	1.0089	0.9972	1.0000

The resulting geometric mean, except in the GS 3000-4999 kW customer class as discussed earlier, is applied to the 2010 customer/connection numbers to determine the forecast of customer/connections in 2011 and 2012. In Table 3-8 above, it can be noted that the USL

category has been adjusted to a growth rate in customers of 1.0. This is based on industry knowledge and local distribution area expertise.

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. Table 3-9 provides the average annual usage per customer by rate class from 2004 to 2010.

Table 3-9 Annual kWh Usage per Customer / Connection

Table 3-9
Annual kWh Usage per Customer/Connection

Year	Residential	General Service < 50kW	General Service 50 - 2999 kW	General Service 3000 - 4999 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
2004	9,584	32,416	822,318	25,202,991	729	1,305	9,311
2005	9,639	31,462	809,737	20,215,158	724	1,279	9,467
2006	9,115	31,088	858,491	23,443,190	718	1,301	8,486
2007	9,203	32,695	917,555	20,583,615	713	1,312	7,520
2008	9,089	33,010	911,513	18,805,505	668	1,430	7,639
2009	8,778	32,521	885,364	19,554,367	488	1,509	7,886
2010	8,747	31,992	914,758	19,036,344	434	1,461	9,337

As can been seen from Table 3-9 above, usage per customer/connection begins to decline in the Residential class after 2005 with a slight increase in 2007, however, decreases again thereafter. It is LUI's view this decline is partially due to the CDM programs initiated in 2005.

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed which is provided in Table 3-10. The geometric mean growth rate has also been shown. However in the case of unmetered customers, including Streetlights, Sentinel Lights, and Unmetered Scattered Load (USL) , the Geomean does not accurately reflect anticipated growth in these classes. LUI has made a knowledgeable and educated change to these figures of "0.9170", "1.0190" and "1.0005" , respectively to a stable 1.0. This can be seen in Table 3-10 below. This is in order to ensure that there are no future increases in these customer classes based on our experience with our distribution area and our striving to ensure that all new distribution is metered where possible. It is known that LDC's

(including LUI) are steering away from USL customer class with the intent of metering as many connections as possible. LUI has been ensuring that current and future loads will all be attempted to be metered, where possible. Clearly, this will cause the unmetered classes to decline over time.

Table 3-10 Growth Rate in Usage per Customer / Connection

Table 3-10
Growth Rate in Usage per Customer / Connection

Year	Residential	General Service < 50kW	General Service 50 - 2999 kW	General Service 3000 - 4999 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
2004							
2005	1.0057	0.9706	0.9847	0.0000	0.9936	0.9801	1.0168
2006	0.9457	0.9881	1.0602	0.0000	0.9917	1.0169	0.8964
2007	1.0096	1.0517	1.0688	0.0000	0.9924	1.0090	0.8861
2008	0.9877	1.0096	0.9934	0.0000	0.9375	1.0894	1.0159
2009	0.9657	0.9852	0.9713	0.0000	0.7297	1.0553	1.0323
2010	0.9965	0.9837	1.0332	0.0000	0.8889	0.9681	1.1840
Geometric Mean (or adjusted)	0.9849	0.9978	1.0179	0.0000	1.0000	1.0000	1.0000
GEOMEAN ACTUAL	0.9849	0.9978	1.0179		0.9170	1.0190	1.0005

Conservation and Demand Management Adjustment

LUI supports the Provincial Government's Conservation and Demand Management ("CDM") initiatives and from 2005 to 2007 delivered CDM programs funded through 3rd tranche revenue and is currently delivering CDM programs that are funded through the Ontario Power Authority ("OPA"). The impact of these historical programs on the load in future years is incorporated in the load forecast presented in this Exhibit, through the modeling process.
On March 31, 2010, the Minister of Energy and Infrastructure issued a Directive to the Ontario Energy Board (the "Board") to establish electricity conservation and demand management targets for each local distribution company ("LDC"). These targets must total 1,330 MW of provincial peak demand and 6,000 GWh of reduced electricity consumption over a four year

period starting in 2011. The OEB (EB-2010-0216) issued proposed CDM Targets for each distributor on June 22, 2010 and LUI has been given a proposed CDM Target reduction of 13,590,000 kWh.

In this application LUI has reflected a decrease of 1,359,000 kWh in 2011 and a total decrease of 2,718,000 kWh in 2012 representing 10% and 20% of its target, respectively.

The CDM adjustments have not been assigned to a specific rate class; it has been applied on a prorated basis by class energy and demand. Table 3-11 details the application of the CDM Adjustment.

Table 3 – 11 CDM Adjustment

Table 3-11

CDM Adjustment

	2011	2012
Predicted kWh Purchases prior to CDM Adjustment	263,616,591	267,061,709
CDM kWh Target Savings for 2011	1,359,000.00	
CDM kWh Target Savings for 2012		2,718,000.00
Predicted kWh Purchases after CDM Adjustment	262,257,591	264,343,709
Purchases kWh Divided by Total Loss Factor	1.0565	1.0565
kWh to allocate to Rate Classes	248,226,168	250,200,674

The non-normalized weather billed energy forecast has been determined including the CDM Adjustments, however, this needs to be adjusted in order to be aligned with the total weather normalized billed energy forecast.

The difference between non-normalized and normalized forecast is assumed to be the amount related to moving the forecast to a weather normal basis. This difference will be assigned to those rate classes that are weather sensitive. LUI used the weather normalization work completed by Hydro One for LUI for its 2007 Cost Allocation Study as a starting point and has

shown its weather sensitivity by rate class below in Table 3-12. LUI has reviewed previous rate applications and has noted the concern of Intervenors that the Residential and GS <50kW classes are not 100% weather sensitive. LUI has, thus, applied a weather sensitivity factor of 70%, which is the mid-point between the 100% HONI reported for these two classes and the GS 50-2999kW sensitivity factor of 41%. None of the other rate classes were assumed to be weather sensitive.

Table 3-12 Weather Sensitivity

Table 3-12

Weather Sensitivity						
Residential	General Service < 50kW	General Service 50 - 2999 kW	General Service 3000 - 4999 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
70%	70%	41%	0%	0%	0%	0%

As a result, any differences in 2011 and 2012 kWh have been assigned on a prorated basis to each rate classes based on the above level of weather sensitivity. Table 3-13 outlines how the weather sensitive rate classes have been adjusted to align the non-normalized forecast with the normalized forecast.

Table 3-13 Alignment of Non-Normal to Weather Normal Forecast

Table 3-13
Allignment of Non-Normal to Weather Normal Forecast

	Non-Normal Weather Billed Energy Forecast (kWh)							
Year	Residential	General Service < 50kW	General Service 50 - 2999 kW	General Service 3000 - 4999 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
2011	72,820,474	34,608,037	120,386,835	19,295,356	1,204,881	78,652	716,623	249,110,857
2012	72,995,567	35,098,326	120,483,014	19,295,356	1,215,575	78,431	716,623	249,882,892

	Adjustment for Weather (kWh)							
Year	Residential	General Service < 50kW	General Service 50 - 2999 kW	General Service 3000 - 4999 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
2011	-361,351	-171,733	-351,605	0	0	0	0	-884,689
2012	129,586	62,308	125,888	0	0	0	0	317,782

	Weather Normalized Billed Energy Forecast (kWh)							
Year	Residential	General Service < 50kW	General Service 50 - 2999 kW	General Service 3000 - 4999 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
2011	72,459,122	34,436,304	120,035,230	19,295,356	1,204,881	78,652	716,623	248,226,168
2012	73,125,152	35,160,634	120,608,902	19,295,356	1,215,575	78,431	716,623	250,200,674

Billed kW Load Forecast

There are four rate classes that charge volumetric distribution on per a kW basis. These include GS 50-2999 kW, GS 3000-4999 kW, Street Lighting, and Sentinel Lighting. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. With the exception of the customer in the GS 3000-4999 kW class which used the average of the 2009 and 2010 actual data, the forecast of kW for the other three classes is based on an average analysis of the historical ratio of kW to kWhs and applying the historical average ratio to the forecasted kWh to produce the required kW. LUI notes that as the CDM Adjustment was applied to kWh, and kWh is being converted to kW, the kW, thus, already reflects the CDM Adjustment, and LUI has not applied any additional CDM adjustments to its forecasted kW.

Table 3-14 outlines the annual demand units by applicable rate class.

Table 3-14 Historical Annual kW

Table 3-14

	Historical Annual kW				
Year	General Service 50 - 2999 kW	General Service 3000 - 4999 kW	Streetlights	Sentinel Lights	Total
2004	291,092	49,683	5,156	199	346,130
2005	295,106	45,661	5,195	195	346,157
2006	297,477	48,479	5,222	211	351,389
2007	300,809	46,227	5,240	212	352,488
2008	298,912	40,464	5,091	225	344,692
2009	290,143	49,629	3,654	222	343,648
2010	299,041	45,256	3,302	219	347,817

LUI notes that trend analysis was raised in the October 26, 2009, EB-2009-0267 Kitchener-Wilmot Hydro Inc. – 2010 Cost of Service Application Interrogatories of Energy Probe, Interrogatory # 14. LUI has adopted the trend analysis approach to provide a forecast of kW for the three applicable rate classes as shown on Table 3-15.

Table 3-15 kW/kWh Ratio

Table 3-15
kW / kWh Ratio

Year	General Service 50 - 2999 kW	General Service 3000 - 4999 kW	Streetlights	Sentinel Lights
2004	0.2432%	N/A	0.2707%	0.2778%
2005	0.2493%	N/A	0.2715%	0.2778%
2006	0.2459%	N/A	0.2714%	0.2778%
2007	0.2457%	N/A	0.2712%	0.2778%
2008	0.2470%	N/A	0.2727%	0.2778%
2009	0.2526%	N/A	0.2705%	0.2778%
2010	0.2486%	N/A	0.2765%	0.2778%
2011 Trended	0.2509%	N/A	0.2744%	0.2778%
2012 Trended	0.2517%	N/A	0.2750%	0.2778%

Table 3-16 outlines the kW forecast for the four applicable rate classes.

Table 3-16 Annual kW Forecast

Table 3-16
Annual kW Forecast

Year	General Service 50 - 2999 kW	General Service 3000 - 4999 kW	Streetlights	Sentinel Lights	Total
2011	301,159	47,442	3,307	218	352,126
2012	303,629	47,442	3,343	218	354,633

A summary of the billing determinants by rate class that has been used to develop the proposed rates is provided in Table 3-17.

Table 3-17 Summary of the billing determinants by rate class

Table 3-17

	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Weather Normal	2012 Weather Normal
Actual kWh Purchases	264,365,121	265,103,480	265,431,760	267,650,333	261,227,184	257,221,767	261,542,031		
Predicted kWh Purchases	263,973,437	265,303,309	265,079,882	266,595,213	261,564,711	259,497,349	260,527,776	262,257,591	264,343,709
% Difference	-0.1%	0.1%	-0.1%	-0.4%	0.1%	0.9%	-0.4%		
Billed kWh	250,404,235	245,534,411	249,730,055	251,838,780	249,119,680	243,045,006	248,087,251	248,226,168	250,200,674
By Class									
Residential									
Customers	7,472	7,539	7,717	7,835	7,942	8,196	8,305	8,453	8,603
kWh	71,606,528	72,668,912	70,342,664	72,101,355	72,186,004	71,936,998	72,645,801	72,459,122	73,125,152
General Service < 50 kW									
Customers	968	1,010	1,041	1,044	1,044	1,061	1,067	1,084	1,102
kWh	31,362,518	31,761,066	32,373,170	34,122,931	34,456,796	34,498,946	34,124,597	34,436,304	35,160,634
General Service 50 - 2,999 kW									
Customers	146	146	141	133	133	130	132	129	127
kWh	119,715,730	118,356,603	120,975,702	122,417,181	121,003,376	114,875,960	120,290,733	120,035,230	120,608,902
kW	291,092	295,106	297,477	300,809	298,912	290,143	299,041	301,159	303,629
Intermediate 3,000 - 4,999 kW									
Customers	1	1	1	1	1	1	1	1	1
kWh	25,202,991	20,215,158	23,443,190	20,583,615	18,805,505	19,554,367	19,036,344	19,295,356	19,295,356
kW	49,683	45,661	48,479	46,227	40,464	49,629	45,256	47,442	47,442
Street Lights									
Connections	2,612	2,641	2,678	2,710	2,793	2,770	2,755	2,779	2,804
kWh	1,904,781	1,913,253	1,923,811	1,931,928	1,867,000	1,350,902	1,194,280	1,204,881	1,215,575
kW	5,156	5,195	5,222	5,240	5,091	3,654	3,302	3,307	3,343
Sentinel Lights									
Connections	55	55	59	58	57	53	54	54	54
kWh	71,663	70,344	76,087	76,442	81,012	79,959	78,873	78,652	78,431
kW	199	195	211	212	225	222	219	218	218
Unmetered Loads									
Connections	58	58	70	81	94	95	77	77	77
kWh	540,024	549,075	595,431	605,328	719,986	747,874	716,623	716,623	716,623
Total									
Customer/Connections	11,311	11,450	11,707	11,861	12,063	12,305	12,390	12,577	12,767
kWh	250,404,235	245,534,411	249,730,055	251,838,780	249,119,680	243,045,006	248,087,251	248,226,168	250,200,674
kW from applicable classes	346,130	346,157	351,389	352,488	344,692	343,648	347,817	352,126	354,633

Appendix A

	Purchased including Losses	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring Fall Flag	Population	Number of Peak Hours	Blackout Flag	Predicted Purchases
Jan-04	23,871,687	872.6	0.0	127.53	31	0	17,599	336	0	23,306,673
Feb-04	20,910,073	636.4	0.0	127.80	29	0	17,676	320	0	21,010,056
Mar-04	20,888,203	519.9	0.0	128.06	31	1	17,753	368	0	20,702,439
Apr-04	18,266,804	372.3	0.0	128.32	30	1	17,830	336	0	19,087,204
May-04	18,021,137	205.4	0.0	128.59	31	1	17,907	320	0	18,300,176
Jun-04	18,180,120	100.8	5.1	128.85	30	0	17,984	352	0	18,618,753
Jul-04	19,198,779	14.7	41.2	129.12	31	0	18,061	336	0	19,443,695
Aug-04	19,397,421	26.9	43.1	129.38	31	0	18,138	336	0	19,340,970
Sep-04	18,753,233	50.3	18.1	129.65	30	1	18,215	336	0	17,707,504
Oct-04	18,546,757	250.1	0.0	129.92	31	1	18,292	320	0	18,431,084
Nov-04	19,666,552	411.0	0.0	130.19	30	1	18,369	352	0	19,493,060
Dec-04	22,056,213	645.2	0.0	**130.45**	31	0	18,446	336	0	21,923,679
Jan-05	23,291,134	782.8	0.0	130.74	31	0	18,523	320	0	22,844,129
Feb-05	20,193,156	631.3	0.0	131.03	28	0	18,600	320	0	20,708,281
Mar-05	21,217,408	612.1	0.0	131.33	31	1	18,677	352	0	21,258,782
Apr-05	18,028,439	362.5	0.0	131.62	30	1	18,754	336	0	19,130,045
May-05	18,097,091	259.9	0.0	131.91	31	1	18,831	336	0	18,885,654
Jun-05	20,058,286	40.7	52.6	132.20	30	0	18,908	352	0	19,772,592
Jul-05	20,975,305	4.2	116.8	132.50	31	0	18,985	320	0	21,586,987
Aug-05	20,798,548	1.0	87.6	132.79	31	0	19,062	352	1	20,798,548
Sep-05	18,990,700	45.5	16.3	133.09	30	1	19,139	336	0	17,820,569
Oct-05	19,252,661	251.9	0.0	133.38	31	1	19,216	320	0	18,803,645
Nov-05	20,235,767	411.5	0.0	133.68	30	1	19,293	352	0	19,719,661
Dec-05	22,138,682	668.4	0.0	**133.98**	31	0	19,370	320	0	22,148,111
Jan-06	22,353,672	589.0	0.0	134.25	31	0	19,447	336	0	22,083,160
Feb-06	20,496,667	627.2	0.0	134.53	28	0	19,469	320	0	20,961,611
Mar-06	21,553,232	564.4	0.0	134.81	31	1	19,491	368	0	21,390,375
Apr-06	18,459,427	342.6	0.0	135.08	30	1	19,513	304	0	18,984,731
May-06	18,600,606	192.1	6.3	135.36	31	1	19,535	352	0	19,080,483
Jun-06	19,219,684	40.1	18.0	135.64	30	0	19,557	352	0	18,926,979
Jul-06	20,843,078	5.9	86.9	135.92	31	0	19,579	320	0	20,915,568
Aug-06	20,373,183	6.7	56.4	136.20	31	0	19,601	352	0	20,247,733
Sep-06	18,316,623	103.3	1.3	136.48	30	1	19,623	320	0	17,729,224
Oct-06	19,515,258	296.4	0.0	136.76	31	1	19,645	336	0	19,315,916
Nov-06	19,920,563	390.9	0.0	137.04	30	1	19,667	352	0	19,419,423
Dec-06	20,765,675	505.5	0.0	**137.33**	31	0	19,689	304	0	21,010,587
Jan-07	22,987,138	669.3	0.0	137.59	31	0	19,711	352	0	22,706,109
Feb-07	21,857,069	728.2	0.0	137.85	28	0	19,733	320	0	21,653,589
Mar-07	22,040,188	578.3	0.0	138.11	31	1	19,755	352	0	21,359,898
Apr-07	19,170,035	401.0	0.0	138.37	30	1	19,777	320	0	19,552,584
May-07	18,185,643	208.1	1.9	138.63	31	1	19,799	352	0	19,165,749
Jun-07	19,516,295	45.4	19.9	138.90	30	0	19,821	336	0	19,078,218
Jul-07	19,530,696	22.4	45.3	139.16	31	0	19,843	336	0	19,975,437
Aug-07	21,202,777	12.1	91.5	139.42	31	0	19,865	352	0	21,677,633
Sep-07	19,037,607	61.8	17.9	139.69	30	1	19,887	304	0	17,970,434
Oct-07	19,430,361	165.8	4.1	139.95	31	1	19,909	352	0	19,071,780
Nov-07	20,663,157	441.5	0.0	140.22	30	1	19,931	352	0	20,321,062
Dec-07	22,153,420	648.3	0.0	**140.48**	31	0	19,953	304	0	22,186,774
Jan-08	22,589,763	633.3	0.0	140.43	31	0	19,975	352	0	22,341,460
Feb-08	21,600,193	660.6	0.0	140.37	29	0	19,997	320	0	21,656,403
Mar-08	21,847,885	632.3	0.0	140.31	31	1	20,019	304	0	21,215,018
Apr-08	18,632,235	326.3	0.0	140.25	30	1	20,041	352	0	19,319,848
May-08	18,130,713	253.6	0.0	140.19	31	1	20,063	336	0	18,950,462
Jun-08	18,986,788	71.0	2.6	140.13	30	0	20,085	336	0	18,622,156
Jul-08	20,523,230	9.4	50.9	140.07	31	0	20,107	352	0	20,360,656
Aug-08	19,554,027	15.2	40.4	140.02	31	0	20,129	320	0	19,573,902
Sep-08	18,984,401	73.5	16.2	139.96	30	1	20,151	336	0	18,315,012
Oct-08	19,133,121	288.1	0.0	139.90	31	1	20,173	352	0	19,559,718
Nov-08	19,701,425	459.0	0.0	139.84	30	1	20,195	304	0	19,609,972
Dec-08	21,823,926	652.5	0.0	**139.78**	31	0	20,217	336	0	22,320,629
Jan-09	23,540,708	823.9	0.0	139.38	31	0	20,239	336	0	23,401,578
Feb-09	20,020,878	608.5	0.0	138.98	28	0	20,261	304	0	20,472,886
Mar-09	20,913,286	568.1	0.0	138.58	31	1	20,283	352	0	21,055,617
Apr-09	18,459,204	345.4	0.0	138.18	30	1	20,305	320	0	18,822,830
May-09	17,573,977	231.1	0.0	137.78	31	1	20,327	320	0	18,643,982
Jun-09	18,427,123	86.1	17.4	137.38	30	0	20,349	352	0	19,226,736
Jul-09	18,988,126	41.5	18.2	136.99	31	0	20,371	352	0	19,119,558
Aug-09	20,387,940	15.7	58.6	136.59	31	0	20,393	320	0	20,018,385
Sep-09	18,406,762	70.1	11.6	136.20	30	1	20,415	336	0	17,677,616
Oct-09	19,177,043	313.3	0.0	135.81	31	1	20,437	336	0	19,366,272
Nov-09	19,018,823	361.0	0.0	135.42	30	1	20,459	320	0	19,010,026
Dec-09	21,612,929	638.6	0.0	**135.03**	31	0	20,469	352	0	21,986,895
Jan-10	23,225,364	718.0	0.0	135.33	31	0	20,478	320	0	22,367,473
Feb-10	20,627,099	597.2	0.0	135.63	28	0	20,488	304	0	20,379,269
Mar-10	20,544,848	450.7	0.0	135.93	31	1	20,497	368	0	20,444,388
Apr-10	17,935,300	262.7	0.0	136.23	30	1	20,507	320	0	18,406,235
May-10	18,762,393	160.4	9.1	136.54	31	1	20,516	320	0	18,539,092
Jun-10	19,299,625	37.9	15.7	136.84	30	0	20,526	352	0	18,783,681
Jul-10	21,197,669	5.1	90.2	137.14	31	0	20,535	336	0	21,058,495
Aug-10	21,010,666	6.0	80.7	137.45	31	0	20,545	336	0	20,922,402
Sep-10	18,015,694	99.9	14.4	137.75	30	1	20,554	336	0	18,167,650
Oct-10	18,447,374	265.5	0.0	138.06	31	1	20,564	320	0	18,934,537
Nov-10	19,847,984	412.1	0.0	138.37	30	1	20,568	336	0	19,650,162
Dec-10	22,559,251	676.5	0.0	**138.67**	31	0	20,568	368	0	22,805,629
Jan-11		727.0	0.0	139.0	31	0	20,577	352	0	22,877,405
Feb-11		641.3	0.0	139.3	28	0	20,587	320	0	20,971,818
Mar-11		560.8	0.0	139.6	31	1	20,596	352	0	21,139,811
Apr-11		344.7	0.0	139.9	30	1	20,606	320	0	19,061,036
May-11		215.8	2.5	140.2	31	1	20,615	352	0	19,067,005
Jun-11		60.3	18.8	140.5	30	0	20,625	336	0	19,120,391
Jul-11		14.7	64.2	140.8	31	0	20,634	336	0	20,586,144
Aug-11		11.9	65.5	141.1	31	0	20,644	352	0	20,791,294
Sep-11		72.1	13.7	141.4	30	1	20,653	304	0	17,933,185
Oct-11		261.6	0.6	141.7	31	1	20,663	352	0	19,542,098
Nov-11		412.4	0.0	142.0	30	1	20,667	352	0	20,017,919
Dec-11		633.6	0.0	142.3	31	0	20,667	304	0	22,122,426
Jan-12		706.2	0.0	142.6	31	0	20,676	352	0	23,016,523
Feb-12		642.0	0.0	142.9	29	0	20,686	320	0	21,626,737
Mar-12		566.7	0.0	143.2	31	1	20,695	304	0	21,014,158
Apr-12		340.7	0.0	143.5	30	1	20,705	352	0	19,597,111
May-12		217.3	2.8	143.8	31	1	20,714	336	0	19,213,241
Jun-12		54.5	20.7	144.1	30	0	20,724	336	0	19,411,131
Jul-12		14.7	67.5	144.4	31	0	20,733	352	0	21,098,301
Aug-12		9.8	68.7	144.7	31	0	20,743	320	0	20,857,676
Sep-12		75.2	13.1	145.0	30	1	20,752	336	0	18,492,938
Oct-12		263.2	0.7	145.4	31	1	20,762	352	0	19,825,320
Nov-12		412.6	0.0	145.7	30	1	20,766	304	0	19,855,164
Dec-12		631.9	0.0	146.0	31	0	20,766	336	0	22,667,348

OPERATING REVENUE VARIANCE ANALYSIS

THROUGHPUT REVENUE and OTHER OPERATING REVENUE

Throughput Revenue

Throughput revenues in this application includes fixed charges revenue from monthly charges, multiplied by the number of customers forecast in the year (for Bridge and Test Years).

2011 Throughput Revenues

LUI's Throughput Revenue for the 2011 Bridge Year has been calculated using its most recently approved rates and estimated number of customers and consumption.

Table 3-18 Forecast Class Billing Determinants for 2011 Bridge

Forecast Class Billing Determinants for 2011 Test Year Based on Existing Class Revenue Proportions
Revenue At Existing Rates

Class	Annual kWh	Annual kW For Dx	Annualized Customers	Annualized Connections	Fixed Distribution Revenue	Variable Distribution Revenue	Dist. Rev. Including Transformer	Transformer Allowance	Dist. Rev. Excluding Transformer	Dist Rev At Existing Rates %
Residential	72,459,122		101,435		942,335	970,952	1,913,288		1,913,288	48.23%
GS < 50 kW	34,436,304		13,010		292,722	278,934	571,656		571,656	14.41%
GS 50-2999	120,035,230	301,159	1,551		285,237	1,029,993	1,315,230	120,237	1,194,993	30.12%
GS 3000 - 4999	19,295,356	47,442	12		21,203	48,714	69,917	28,465	41,451	1.04%
Sentinel Lights	78,652	218		646	3,011	2,507	5,518		5,518	0.14%
Street Lighting	1,204,881	3,307		33,348	128,058	80,491	208,549		208,549	5.26%
USL	716,623			921	10,334	20,997	31,331		31,331	0.79%
0		0			0	0	0		0	0.00%
0	0	0	0		0	0	0		0	0.00%
	248,226,168	**352,126**	**116,009**	**34,916**	**1,682,900**	**2,432,588**	**4,115,489**	**148,703**	**3,966,786**	**100%**

2012 Throughput Revenues

LUI's Throughput Revenues at existing rates for the 2012 Test Year have been calculated using the most recently approved rates and estimated number of customers and consumption.

Table 3- 19 Forecast Class Billing Determinants for 2012 Test

Forecast Class Billing Determinants for 2012 Test Year Based on Existing Class Revenue Proportions
Revenue At Existing Rates

Class	Annual kWh	Annual kW For Dx	Annualized Customers	Annualized Connections	Fixed Distribution Revenue	Variable Distribution Revenue	Dist. Rev. Including Transformer	Transformer Allowance	Dist. Rev. Excluding Transformer	Dist Rev At Existing Rates %
Residential	73,125,152		103,239		959,095	979,877	1,938,971.56		1,938,972	48.37%
GS < 50 kW	35,160,634		13,223		297,522	284,801	582,322.67		582,323	14.53%
GS 50-2999	120,608,902	303,629	1,525		280,441	1,038,442	1,318,883.30	120,237.13	1,198,646	29.90%
GS 3000 - 4999	19,295,356	47,442	12		21,203	48,714	69,916.56	28,465.39	41,451	1.03%
Sentinel Lights	78,431	218		644.3743	3,003	2,500	5,502.50		5,503	0.14%
Street Lighting	1,215,575	3,343		33,644	129,195	81,381	210,575.96		210,576	5.25%
USL	716,623		921		10,334	20,997	31,330.67		31,331	0.78%
0		0			0	0	0		0	0.00%
0	0	0	0		0	0	0		0	0.00%
	250,200,674	**354,633**	**118,921**	**34,289**	**1,700,791**	**2,456,712**	**4,157,503**	**148,703**	**4,008,801**	**100%**

In Table 3-20 below, we demonstrate the Throughput Revenues at new rates for the 2012 Test Year that were calculated during rate design taking into account the revenue deficiency.; using forecasted number of customers/connections and consumption.

Table 3-20 Distribution Rate Allocation Between Fixed & Variable Rates for 2012

Distribution Rate Allocation Between Fixed & Variable Rates For 2012 Test Year

Customer Class	Total Net Rev. Requirement	Rev Requirement %	Proposed Fixed Rate	Resulting Variable Rate	Total Fixed Revenue	Total Variable Revenue	Transformer Allowance	Gross Distribution Revenue	LV & Wheeling Charges	Total
Residential	2,556,790	53.80%	12.25	$0.0177	$ 1,264,693	$ 1,292,097		2,556,790	97,140	2,653,931
GS < 50 kW	725,309	15.26%	28.02	$0.0101	$ 370,576	$ 354,733		725,309	42,363	767,672
GS 50-2999	1,181,345	24.86%	181.20	$3.3764	$ 276,393	$ 904,951	$ 120,237	1,301,582	145,073	1,446,655
GS 3000 - 4999	61,414	1.29%	2,617.84	$1.2323	$ 31,414	$ 30,000	$ 28,465	89,880	26,735	116,614
Sentinel Lights	5,072	0.11%	4.30	$10.5767	$ 2,768	$ 2,304		5,072	82	5,154
Street Lighting	178,720	3.76%	3.26	$20.6590	$ 109,650	$ 69,070		178,720	1,235	179,955
USL	44,091	0.93%	15.79	$0.0412	$ 14,542	$ 29,549		44,091	1,063	45,154
0	0	0.00%		$0.0000	$ -	$ -		0	0	0
0	0	0.00%		$0.0000	$ -	$ -		0	0	0
TOTAL	**4,752,742**	**100%**			**$ 2,070,037**	**$ 2,682,704**	**$ 148,703**	**$ 4,901,444**	**$ 313,691**	**$ 5,215,135**
			Forecast Fixed/Variable Ratios		**42.233%**	**54.733%**	**3.034%**	**100.000%**		

Overall LUI has had both load increases and load decreases from 2007 to the 2012 forecast year, depending on the customer class. The biggest change is in GS 3000-4999 class as this customer class has decreased since our last Cost of Service. This is due to the loss of a major

customer, Un-named customer. Un-named customer was phased out during 2008-2010. LUI now has just one customer in the GS 3000-4999 customer class and expect no change in this class. Note that the Un-named customer, as was discussed in Load Forecasting above, has been removed from all data. The decreases in load can be attributed to the success of conservation initiatives undertaken by LUI Customers. The increases can be attributed to economic growth in the small business sector in Cobourg. See Table 3-2 of this exhibit.

Information related to Lakefront Utilities Inc.'s throughput revenue includes details such as weather normalized forecasting methodology, normalized volume based on historical number of customers billed throughout the year and CDM adjustments and known economic conditions.

A detailed variance analysis on the throughput revenue is set out later in this Exhibit.

OTHER REVENUE

Other revenues include Standard Service Supply (SSS) Administration Charges, Late Payment Charges, Miscellaneous Service Revenues, Rent from Electric Property, Interdepartmental Rents, Service Transaction Requests, Retail Service Revenues and Interest and Dividend Income. The fall in bank interest rates had a significant impact on other revenue as interest income declined.

VARIANCE ANALYSIS ON THROUGHPUT REVENUE

A summary of historical and forecast operating revenues is presented in Table 3-0. LUI's distribution revenue has been calculated using its most recently approved rates. In particular, delivery rates are based on the EB-2010-0095 Decision and Order dated March 17, 2011. Throughput revenue does not include commodity-related revenue.

From Exhibit 3-0, we discuss the significant changes below.

2008 Board Approved

LUI's Total 2008 Board Approved operating revenue was forecast to be $ 4,320,810 . Throughput revenue of $ 3,985,246 represented 92.2% of total operating revenue. Other net operating revenue accounts for the remaining $ 335,564.

Comparison 2008 Actual to 2008 Board Approved – Throughput Revenue

Table 3-21 Comparison 2008 to 2008 Board Approved

Summary of Operating Revenue Table	2008 Board Approved ($'s)	2008 Actual ($'s)	Variance from 2008 Board Approved ($'s)
Distribution Revenue			
Residential	1,917,386	1,840,952	(76,434)
GS < 50 kW	656,516	619,069	(37,447)
GS > 50 - 2999 kW	1,208,240	1,163,463	(44,777)
GS > 3000 - 4999 kW	97,123	23,437	(73,686)
Streetlight	73,925	36,635	(37,290)
Sentinel Light	3,327	2,537	(790)
Unmetered Scattered Load	28,729	31,905	3,176
Total	3,985,246	3,717,998	(267,248)
Other Distribution Revenue			
Specific Service Charges	103,267	133,125	29,858
Late Payment Charges	27,565	72,437	44,872
Other Distribution Revenue	149,461	158,868	9,407
Other Income and Expenses	55,271	821,667	766,396
Total	335,564	1,186,098	850,534
Grand Total:	4,320,810	4,904,096	583,286

2008 Actual

LUI's operating revenue in fiscal 2008 was $ 4,904,096. Throughput revenue was $ 3,717,998 or 75.8% of total revenues. Other net operating revenue accounts for the remaining $ 1,186,098.

Throughput revenue for 2008 was $ (267,248) lower than the amounts approved in the 2008 Cost of Service primarily due to lower kWh usage attributable to conservation initiatives that were undertaken, in the residential, general service <50, and intermediate rate class. The reduction in the intermediate rate class is also attributable to the loss of a major intermediate customer. The timing difference between the 2008 Actual amounts which are based on the fiscal year of January 1 to December 31, 2008, and the 2008 Board Approved amounts, which are based on the rate year of May 1 2008 to April 30 ,2009 also contribute to the variance, since the 2008 rates did not come into effect until July 2008.

Variances in Other Revenue relate to CDM/OPA funding and transition costs. Prior to transition costs, BDO Dunwoody, our external auditors for the year, requested that we write off our transition costs to expense, as they were not confident that these costs were recoverable going forward. Therefore upon their request, LUI removed these costs and expensed them. In the following years, the OEB performed a transition costs review and it was determined that transition costs were recoverable and therefore our external auditors allowed us to bring the costs back onto our financial statements, over 3 year period. Year three, was 2008 and therefore we see a large amount of transition costs that were included in income, of $561,710 in 2008. This was our final year of cost "recovery" and was a result of a prudence assessment to provide complete and accurate data in our financial statements.

LUI also included revenues and expenses resulting from Conservation and Demand Management activities in account 4375 and 4380. LUI did not net the expenses and the revenues in 2008 and therefore shows a revenue stream from OPA funding related to CDM activities.

Finally, we note that in this account, for presentation purposes, we show the interest revenue/expense amount in 4405, interest income, on the deferral and variance accounts, which balances to our financial statements. For the purposes of the rate application, these amounts are not included in determining revenue offsets, however are included in the analysis for the purposes of presenting complete financial data.

Comparison 2008 Actual to 2009 Actual – Throughput Revenue

Table 3-22 Comparison 2008 to 2009

Summary of Operating Revenue Table	2008 Actual ($'s)	2009 Actual ($'s)	Variance from 2008 Actual ($'s)
Distribution Revenue			
Residential	1,840,952	1,970,658	129,707
GS < 50 kW	619,069	619,738	670
GS > 50 - 2999 kW	1,163,463	1,233,761	70,298
GS > 3000 - 4999 kW	23,437	62,334	38,897
Streetlight	36,635	81,308	44,673
Sentinel Light	2,537	3,944	1,407
Unmetered Scattered Load	31,905	33,981	2,076
Total	3,717,998	4,005,725	287,728
			7.7%
Other Distribution Revenue			
Specific Service Charges	133,125	144,453	11,328
Late Payment Charges	72,437	61,033	(11,404)
Other Distribution Revenue	158,868	166,728	7,859
Other Income and Expenses	821,667	108,311	(713,356)
Total	1,186,098	480,525	(705,573)
Grand Total:	4,904,096	4,486,250	(417,845)
% of Total Revenues	75.8%	89.3%	-68.9%

2009 Actual

LUI's operating revenue for 2009 was $ 4,486,250 ,and throughput revenue was $ 4,005,725 or 89.3% of total revenues. Net other operating revenue accounts for the remaining revenue of $ 480,525 .

The 2009 throughput revenue was $ 287,728 or 7.7% higher than the 2008 actual revenue. Despite the immaterial load reductions for the general service classes, revenue increased for all rate classes due to small economic growth as well as timing differences between the fiscal and rate year periods.

Comparison 2009 Actual to 2010 Actual Throughput Revenue

Table 3-23Comparison 2009 to 2010

Summary of Operating Revenue Table	2009 Actual ($'s)	2010 Actual ($'s)	Variance from 2009 Actual ($'s)
Distribution Revenue			
Residential	1,970,658	1,909,334	(61,324)
GS < 50 kW	619,738	599,095	(20,644)
GS > 50 - 2999 kW	1,233,761	1,279,944	46,182
GS > 3000 - 4999 kW	62,334	46,650	(15,684)
Streetlight	81,308	138,517	57,209
Sentinel Light	3,944	4,489	546
Unmetered Scattered Load	33,981	32,830	(1,151)
Total	4,005,725	4,010,859	5,134
			0.13%
Other Distribution Revenue			
Specific Service Charges	144,453	127,499	(16,954)
Late Payment Charges	61,033	63,140	2,107
Other Distribution Revenue	166,728	157,273	(9,455)
Other Income and Expenses	108,311	60,931	(47,380)
Total	480,525	408,843	(71,682)
Grand Total:	4,486,250	4,419,702	(66,548)
% of Total Revenues	89.3%	90.7%	-7.7%

2010 Actual

LUI's operating revenue in fiscal 2010 was $ 4,419,702, and throughput revenue totaled $ 4,010,859 or 90.7% of total revenues. Other net operating revenue accounts for the remaining revenue of $ 408,843.

Throughput revenue in 2010 was 0.13% or $ 5,134 higher than in 2009 due to a combination of conservation and demand initiatives. There was moderate customer growth in the other customer classes, however offsetting kWh usage.

Comparison of 2011 Bridge to 2010 Actual Throughput Revenue

Table 3-24 Comparison 2011 to 2010

Summary of Operating Revenue Table	2010 Actual ($'s)	2011 Bridge ($'s)	Variance from 2010 Actual ($'s)
Distribution Revenue			
Residential	1,909,334	1,913,288	3,954
GS < 50 kW	599,095	571,656	(27,438)
GS > 50 - 2999 kW	1,279,944	1,194,993	(84,951)
GS > 3000 - 4999 kW	46,650	41,451	(5,199)
Streetlight	138,517	208,549	70,032
Sentinel Light	4,489	5,518	1,029
Unmetered Scattered Load	32,830	31,331	(1,499)
Total	4,010,859	3,966,786	(44,073)
			-1.10%
Other Distribution Revenue			
Specific Service Charges	127,499	127,000	(499)
Late Payment Charges	63,140	63,140	-
Other Distribution Revenue	157,273	160,406	3,133
Other Income and Expenses	60,931	28,500	(32,431)
Total	408,843	379,046	(29,797)
Grand Total:	4,419,702	4,345,832	(73,870)
% of Total Revenues	90.7%	91.3%	59.7%

2011 Bridge Year

Throughput revenue is expected to decrease by -1.10% or $(44,073) in 2011. This is a result of a decrease in usage for GS<50, GS 50-2999, GS 3000-4999 customer classes, along with conservation and demand management initiatives.

The reason for the decrease in other income and Expenses is due to prior year (2010) showing interest expenses on deferral & variance accounts, whereas the forecast interest is without those expenses, as per the filing requirements.

Comparison 2012 Test to 2011 Bridge Actual Throughput Revenue

Table 3-25 – Comparison 2012 Test to 2011 Bridge

Summary of Operating Revenue Table	2011 Bridge ($'s)	2012 Test ($'s)	Variance from 2011 Bridge ($'s)
Distribution Revenue			
Residential	1,913,288	2,556,790	643,502
GS < 50 kW	571,656	725,309	153,653
GS > 50 - 2999 kW	1,194,993	1,181,345	(13,649)
GS > 3000 - 4999 kW	41,451	61,414	19,963
Streetlight	208,549	178,720	(29,829)
Sentinel Light	5,518	5,072	(446)
Unmetered Scattered Load	31,331	44,091	12,760
Total	3,966,786	4,752,742	785,956
			19.81%
Other Distribution Revenue			
Specific Service Charges	127,000	126,500	(500)
Late Payment Charges	63,140	63,140	-
Other Distribution Revenue	160,406	160,322	(84)
Other Income and Expenses	28,500	28,500	-
Total	379,046	378,462	(584)
Grand Total:	4,345,832	5,131,204	785,371
% of Total Revenues	91.3%	92.6%	100.1%

2012 Test Year

LUI's operating revenue is forecast to be $ 5,131,204 as shown in Table 3-25. Throughput revenue totals $ 4,752,740 or 92.6% of total revenues. Other net operating revenue accounts for the remaining revenue of $ 378,462.

Total throughput operating revenue is forecast to be $ 785,956 or 19.81% higher than the 2011 Bridge year. This variance is due to increased revenue required as determined through the Revenue Deficiency of $ 743,941 . Exhibit 6 provides further details on the revenue deficiency for 2012 Test year. As a result of this rate application, LUI expects to increase its rate base by $ 3,112,743 or 21.60% over the 2008 Cost of Service rate base as explained in Exhibit 2.

TRANSFORMER ALLOWANCE

LUI currently provides a Transformer Ownership Allowance Credit of $0.60 per kW of demand per month for all customers who own their own transformer facilities.

LUI is proposing to maintain the rate of $0.60 per kW of demand per month for the 2012 Test Year for eligible customers.

VARIANCE ANALYSIS ON OTHER OPERATING REVENUE

Table 3-26 provides a summary of Other Operating Revenue between 2008 Approved through to 2012 Test Year Amounts.

Table 3-26 Summary of Other Distribution Revenue

SUMMARY OF OTHER DISTRIBUTION REVENUE

Expense Description	2008 Board Approved	2008 Actual	Variance from 2008 Board Approved	2009 Actual	Variance from 2008 Actual	2010 Actual	Variance from 2009 Actual	2011 Bridge	Variance from 2010 Actual	2012 Test	Variance from 2011 Bridge
Other Distribution Revenue											
4082-Retail Services Revenues	12,022	13,320	1,298	10,013	(3,307)	10,178	165	10,015	(163)	9,985	(30)
4084-Service Transaction Requests (STR) Revenues	347	1,380	1,033	4,560	3,180	4,774	214	4,560	(214)	4,015	(545)
4205 - Interdepartmental Rents	45,600	51,600	6,000	51,600	0	51,600	0	51,600	0	51,600	0
4210-Rent from Electric Property	56,300	59,777	3,477	65,115	5,338	56,697	(8,418)	56,500	(197)	56,400	(100)
4225-Late Payment Charges	27,565	72,437	44,872	61,033	(11,404)	63,140	2,107	63,140	0	63,140	0
4235-Miscellaneous Service Revenues	103,267	133,125	29,858	144,453	11,328	127,499	(16,954)	127,000	(499)	126,500	(500)
4355-Gain on Disposition of Utility and Other Property		0	0	10,178	10,178	0	(10,178)	0	0	0	0
4375- Revenues from Non-Utility Operations		626,554	626,554	36,204	(590,350)	11,991	(24,213)	0	(11,991)	0	0
4405-Interest and Dividend Income	55,271	195,113	139,842	61,929	(133,184)	48,940	(12,989)	28,500	(20,440)	28,500	0
Sub-Total	**300,372**	**1,153,306**	**852,934**	**445,085**	**(708,221)**	**374,818**	**(70,267)**	**341,315**	**(33,503)**	**340,140**	**(1,175)**
4080-Distribution Services Revenue- SSS Admin Fee	35,192	32,791	(2,401)	35,440	2,648	34,024	(1,416)	37,731	3,707	38,322	591
Total	**335,564**	**1,186,098**	**850,534**	**480,525**	**(705,573)**	**408,843**	**(71,682)**	**379,046**	**(29,797)**	**378,462**	**(584)**

Specific Service Charges	103,267	133,125	29,858	144,453	11,328	127,499	(16,954)	127,000	(499)	126,500	(500)
Late Payment Charges	27,565	72,437	44,872	61,033	(11,404)	63,140	2,107	63,140	0	63,140	0
Other Distribution Revenues	149,461	158,868	9,407	166,728	7,859	157,273	(9,455)	160,406	3,133	160,322	(84)
Other Income and Expenses	55,271	821,667	766,396	108,311	(713,356)	60,931	(47,380)	28,500	(32,431)	28,500	0
Total	**335,564**	**1,186,098**	850,534	**480,525**	**(705,573)**	**408,843**	**(71,682)**	**379,046**	**(29,797)**	**378,462**	**(584)**

VARIANCE ANALYSIS ON OTHER OPERATING REVENUE:

OVERVIEW

LUI's service revenue requirement for the purposes of this application is 5,131,204, and the base revenue requirement is 4,752,741. The materiality threshold used to analyze Other Operating Revenue accounts in accordance with the Filing Requirements is $50,000 for distributors with a distribution revenue requirement less than or equal to $10 million. LUI will, describe variances that are above the materiality threshold of $50,000 in order to provide a meaningful analysis of the activity in the Other Operating Revenue accounts.

2008 Board Approved Comparison to 2008 Actual – Other Operating Revenue

Table 3-27 below summarizes the variance by account description followed by a discussion on those variances over $50,000.

Table 3-27 2008 Board Approved vs. 2008 Actual Variance by Account

Expense Description	2008 Board Approved	2008 Actual	Variance from 2008 Board Approved
Other Distribution Revenue			
4082-Retail Services Revenues	12,022	13,320	1,298
4084-Service Transaction Requests (STR) Revenues	347	1,380	1,033
4205 - Interdepartmental Rents	45,600	51,600	6,000
4210-Rent from Electric Property	56,300	59,777	3,477
4225-Late Payment Charges	27,565	72,437	44,872
4235-Miscellaneous Service Revenues	103,267	133,125	29,858
4355-Gain on Disposition of Utility and Other Property		0	0
4375- Revenues from Non-Utility Operations		626,554	626,554
4405-Interest and Dividend Income	55,271	195,113	139,842
Sub-Total	**300,372**	**1,153,306**	**852,934**
4080-Distribution Services Revenue- SSS Admin Fee	35,192	32,791	(2,401)
Total	**335,564**	**1,186,098**	**850,534**

Specific Service Charges	103,267	133,125	29,858
Late Payment Charges	27,565	72,437	44,872
Other Distribution Revenues	149,461	158,868	9,407
Other Income and Expenses	55,271	821,667	766,396
Total	**335,564**	**1,186,098**	850,534

After adjusting out the Revenues from Non-Utility Operations (which related to OPA programs and transition costs), LUI's 2008 other operating revenue offset of $ (559,543) was $ (223,979) greater than the Board Approved amount of $335,564.

Specific Service Charges

The 2008 specific service charges increased over board approved due to an unexpected increase in other miscellaneous revenues, specifically related to income received for external services provided for affiliate for sewer billing in the amount of $30,000.

Late Payment Charges

The 2008 Board Approved Late Payment Charges for $ 27,565 and the actual revenues in 2008 was $ 72,437, a difference of $ 44,872. This was due to a larger than anticipated revenue stream from late payment charges on overdue accounts.

Other Income and Expenses

Interest and dividend income of $ 195,113 was $ 139,842 higher than the 2008 Board due to higher than expected interest earned on bank accounts as well as interest earned of deferral & variance accounts.

In the Other Non-Utility Operations Revenues, there are two revenue components; one is the CDM/OPA funding component, and the other is the transition costs. Prior to transition costs, BDO Dunwoody, our external auditors for the year, requested that we write off our transition costs to expense, as they were not confident that these costs were recoverable going forward. Therefore upon their request, LUI removed these costs and expensed them. In the following years, the OEB performed a transition costs review and it was determined that transition costs were recoverable and therefore our external auditors allowed us to bring the costs back onto our financial statements, over 3 year period. Year three, was 2008 and therefore we see a large amount of transition costs that were included in income, of $561,710 in 2008. This was our final year of cost "recovery" and was a result of a prudence assessment to provide complete and accurate data in our financial statements.

LUI also included revenues and expenses resulting from Conservation and Demand Management activities in account 4375 and 4380. LUI did not net the expenses and the revenues in 2008 and therefore shows a revenue stream from OPA funding related to CDM activities.

Finally, we note that in this account, for presentation purposes, we show the interest revenue/expense amount in 4405, interest income, on the deferral and variance accounts, which balances to our financial statements. For the purposes of the rate application, these amounts are not included in determining revenue offsets, however are included in the analysis for the purposes of presenting complete financial data.

2009 Actual Comparison to 2008 Actual – Other Operating Revenue

Table 3-28 below summarizes the variance by account description followed by a discussion on those variances over $50,000.

Table 3-28 2008 vs 2009 Variance by Account

Expense Description	2008 Actual	2009 Actual	Variance from 2008 Actual
Other Distribution Revenue			
4082-Retail Services Revenues	13,320	10,013	(3,307)
4084-Service Transaction Requests (STR) Revenues	1,380	4,560	3,180
4205 - Interdepartmental Rents	51,600	51,600	0
4210-Rent from Electric Property	59,777	65,115	5,338
4225-Late Payment Charges	72,437	61,033	(11,404)
4235-Miscellaneous Service Revenues	133,125	144,453	11,328
4355-Gain on Disposition of Utility and Other Property	0	10,178	10,178
4375- Revenues from Non-Utility Operations	626,554	36,204	(590,350)
4405-Interest and Dividend Income	195,113	61,929	(133,184)
Sub-Total	**1,153,306**	**445,085**	**(708,221)**
4080-Distribution Services Revenue- SSS Admin Fee	32,791	33,279	488
Total	**1,186,098**	**478,364**	**(707,733)**

Specific Service Charges	133,125	144,453	11,328
Late Payment Charges	72,437	61,033	(11,404)
Other Distribution Revenues	158,868	164,567	5,699
Other Income and Expenses	821,667	108,311	(713,356)
Total	**1,186,098**	**478,364**	**(707,733)**

Before adjustment for non-recurring or exception items, LUI's 2009 other operating revenues of $ **478,364** was $ **(707,733)** lower than 2008. However, after adjusting for 2008 CDM revenue and expense, transition costs, and the 2009 Gain on Disposition of Utility and Other

Property, LUI's 2009 other operating revenue offset of $ 478,364 was only $ (127,561) lower than the 2008 revenue offset amount.

Other Income and Expenses

Conversely, 2008 Revenues from Non-Utility Operations decreased by $ (590,350), from the 2008 amount of $ 626,554. In 2009, there were no transition costs remaining to bring into revenues. See previous analysis in 2008 on Other Income and Expenses for analysis of the $626,554 in 2008.

Gross Interest and Dividend income for 2009 was lower than 2008 actual amounts. 2009 balance of $ 61,929 was $ (133,184) lower than the 2008 actuals. This was attributable to declining lower interest attributable to the deferral and variance accounts.

2010 Actual Comparison to 2009 Actual – Other Operating Revenue

Table 3-29 below summarizes the variance by account description followed by a discussion on those variances over $50,000.

Table 3-29 2009 vs 2010 Variance by Account

Expense Description	2009 Actual	2010 Actual	Variance from 2009 Actual
Other Distribution Revenue			
4082-Retail Services Revenues	10,013	10,178	165
4084-Service Transaction Requests (STR) Revenues	4,560	4,774	214
4205 - Interdepartmental Rents	51,600	51,600	0
4210-Rent from Electric Property	65,115	56,697	(8,418)
4225-Late Payment Charges	61,033	63,140	2,107
4235-Miscellaneous Service Revenues	144,453	127,499	(16,954)
4355-Gain on Disposition of Utility and Other Property	10,178	0	(10,178)
4375- Revenues from Non-Utility Operations	36,204	11,991	(24,213)
4405-Interest and Dividend Income	61,929	48,940	(12,989)
Sub-Total	**445,085**	**374,818**	**(70,267)**
4080-Distribution Services Revenue- SSS Admin Fee	33,279	34,024	745
Total	**478,364**	**408,843**	**(69,521)**

Specific Service Charges	144,453	127,499	(16,954)
Late Payment Charges	61,033	63,140	2,107
Other Distribution Revenues	164,567	157,273	(7,294)
Other Income and Expenses	108,311	60,931	(47,380)
Total	**478,364**	**408,843**	**(69,521)**

Before adjusting for non-recurring or exception items, LUI's 2010 other operating revenues of $ **408,843** was $ **(69,521)** lower than 2009. After adjusting for CDM revenue and expense, and regulatory asset carrying charges, LUI's 2010 other operating revenue offset of $ (396,851) was $ 45,309 lower than the 2009 revenue offset amount of $ 431,982 .

Other Income and Expenses

The decrease in other income and expenses is due to a gain being reported in 2009 that is not in 2010. Also, the amount of revenues earned from OPA funding in 2010 was less than in 2009. Finally, the interest earned on bank account and variance accounts is minimal compared to 2009 due to lower rates on both bank accounts and deferral & variance accounts (OEB prescribed rates).

2011 Bridge Year Comparison to 2010 Actual – Other Operating Revenue

Table 3-30 below summarizes the variance by account description followed by a discussion on those variances over $20,000.

Table 3-30 – 2010 vs 2011 Variance by Account

Expense Description	2010 Actual	2011 Bridge	Variance from 2010 Actual
Other Distribution Revenue			
4082-Retail Services Revenues	10,178	10,015	(163)
4084-Service Transaction Requests (STR) Revenues	4,774	4,560	(214)
4205 - Interdepartmental Rents	51,600	51,600	0
4210-Rent from Electric Property	56,697	56,500	(197)
4225-Late Payment Charges	63,140	63,140	0
4235-Miscellaneous Service Revenues	127,499	127,000	(499)
4355-Gain on Disposition of Utility and Other Property	0	0	0
4375- Revenues from Non-Utility Operations	11,991	0	(11,991)
4405-Interest and Dividend Income	48,940	28,500	(20,440)
Sub-Total	**374,818**	**341,315**	**(33,503)**
4080-Distribution Services Revenue- SSS Admin Fee	34,024	37,731	3,707
Total	**408,843**	**379,046**	**(29,797)**

Specific Service Charges	127,499	127,000	(499)
Late Payment Charges	63,140	63,140	0
Other Distribution Revenues	157,273	160,406	3,133
Other Income and Expenses	60,931	28,500	(32,431)
Total	**408,843**	**379,046**	**(29,797)**

Before adjusting for CDM and Non-Utility Generation revenue and expense, regulatory asset carrying charges, LUI's 2011 other operating revenue offset of $ **379,046** is expected to be $ **(29,797)** lower than the 2010 revenue offset amount of $ **408,843** . After adjusting for the above noted items the variance between the two years is insignificant at $ 17,805 . Given the low variance, no analysis was needed.

2012 Test Year Comparison to 2011 Bridge Year – Other Operating Revenue

Table 3-31 below summarizes the variance by account description followed by a discussion on those variances over $50,000.

Table 3-31 Summary of Other Distribution Revenue

SUMMARY OF OTHER DISTRIBUTION REVENUE

Expense Description	2011 Bridge	2012 Test	Variance from 2011 Bridge
Other Distribution Revenue			
4082-Retail Services Revenues	10,015	9,985	(30)
4084-Service Transaction Requests (STR) Revenues	4,560	4,015	(545)
4205 - Interdepartmental Rents	51,600	51,600	0
4210-Rent from Electric Property	56,500	56,400	(100)
4225-Late Payment Charges	63,140	63,140	0
4235-Miscellaneous Service Revenues	127,000	126,500	(500)
4355-Gain on Disposition of Utility and Other Property	0	0	0
4375- Revenues from Non-Utility Operations	0	0	0
4405-Interest and Dividend Income	28,500	28,500	0
Sub-Total	**341,315**	**340,140**	**(1,175)**
4080-Distribution Services Revenue- SSS Admin Fee	37,731	38,322	591
Total	**379,046**	**378,462**	**(584)**

Specific Service Charges	127,000	126,500	(500)
Late Payment Charges	63,140	63,140	0
Other Distribution Revenues	160,406	160,322	(84)
Other Income and Expenses	28,500	28,500	0
Total	**379,046**	**378,462**	**(584)**

Before adjusting for non-utility and CDM activities, LUI's 2012 Test Year other operating revenue offset is anticipated to be $**378,462**, lower by $**(584)** over Bridge Year 2011. There are no adjustments required in 2011 & 2012 for other non-utility revenues.

SPECIFIC SERVICE CHARGES

LUI is proposing to adjust specific service charges in 2012. The specific service charge that LUI is requesting approval for is a Service Charge for Onsite Interrogation of Interval Meter due to Customer Phone Line Failure. The cost of this service has been investigated by LUI and is equivalent to one service technician, and a fleet vehicle. The purpose of this Service Charge is when a customer's phone line fails; LUI is unable to obtain a reading from that particular customer. The lack of read can cause LUI delays in operations, including, but not limited to, inability to run billing cycle for that customer on the expected due date, inability to obtain monthly up to date data from our web-based data services provider and settlement with the IESO can be delayed or estimated. With this service charge, LUI will cover the costs of sending a technician to the location with an optical probe, which will read the meter and download the file to our web based data services provider, to upload to our system for billing.

Request to Update Current Rates and Specific Charges

LUI is requesting one change to the Specific Service Charge revenue (outlined above) and proposes to add to the specific services charges, in the table below, last line, and maintain the remaining current rates for all of the following:

Table 3-32Additions to Specific Services Charges

Item Description	Calculation Basis	Rate ($)
Arrears certificate	Standard	15.00
Statement of account	Standard	15.00
Pulling post dated cheques	Standard	15.00
Request for other billing information	Standard	15.00
Easement letter	Standard	15.00
Income tax letter	Standard	15.00
Credit reference/credit check (plus credit agency costs)	Standard	15.00
Returned cheque charge (plus bank charges)	Standard	15.00
Legal letter charge	Standard	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	Standard	30.00
Special meter reads	Standard	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	Standard	30.00
Collection of account charge - no disconnection	Standard	30.00
Collection of account charge - no disconnection - after regular hours	Standard	165.00
Disconnect/Reconnect at meter - during regular hours	Standard	65.00
Disconnect/Reconnect at meter - after regular hours	Standard	185.00
Disconnect/Reconnect at pole - during regular hours	Standard	185.00
Disconnect/Reconnect at pole - after regular hours	Standard	415.00
Install/Remove load control device - during regular hours	Standard	65.00
Install/Remove load control device - after regular hours	Standard	185.00
Service call - customer-owned equipment	Standard	30.00
Service call - after regular hours	Standard	165.00
Temporary service install & remove - overhead - no transformer	Standard	500.00
Temporary service install & remove - underground - no transformer	Standard	300.00
Temporary service install & remove - overhead - with transformer	Standard	1,000.00
Specific Charge for Access to the Power Poles $/pole/year	Standard	22.35
Interval Meter Load Management Tool Charge $/month	Standard	110.00
Service charge for onsite interrogation of interval meter due to customer phone line failure -required weekly until line repaired	Standard	60.00

Interest and Dividend Income

Table 3-33 below summarizes the amount and source of interest income from the 2008 Actual to 2012 Test Years. Declining interest rates and lower bank account balances account for the overall decline in revenues. Variance Account Carrying Charges, while noted in this table, are excluded from the revenue offset amount for the purposes of this rate application.

Table 3-33 - Interest and Dividend Income

4405 Interest & Dividend Income	2008 Actual	2009 Actual	2010 Actual	2011 Bridge year	2012 Test year
Long Term interest					
Bank account deposit interest	$13,406.97	$40,865.59	$2,234.51	$8,500.00	$8,500.00
Variance Accounts Carrying Charges	$181,705.94	$9,484.48	$26,910.81	$15,000.00	$15,000.00
Miscellaneous Other		$11,579.00	$19,794.29	$ 20,000.00	$ 20,000.00
Totals	$195,112.91	$ 61,929.07	$ 48,939.61	$43,500.00	$43,500.00
Totals Excluding Variance Accounts Carrying charges	**$13,406.97**	**$52,444.59**	**$22,028.80**	**$28,500.00**	**$28,500.00**

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OVERVIEW OF OPERATING COSTS

Operating Costs

The operating costs presented in this Exhibit represent the annual expenditures required to sustain LUI's distribution operations. LUI follows the OEB's Accounting Procedures Handbook (the "APH") in distinguishing work performed between operations and maintenance. A summary of LUI 's operating costs for 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year and the 2012 Test Year in accordance with the Filing Requirements, is provided in Table 1.1 below. A summary of the variances as required by the Filing Requirements is provided in Tables 1.2 through 1.6.

Table 4.0 Summary of OM&A Expenses

Summary of OM&A Expenses						
Description	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 Test Year
Operations	$ 620,871	$ 617,177	$ 505,675	$ 415,821	$ 579,609	$ 879,396
Maintenance	$ 104,107	$ 77,337	$ 139,615	$ 225,312	$ 306,219	$ 391,786
Billing &Collecting	$ 428,844	$ 440,285	$ 407,715	$ 425,479	$ 501,542	$ 500,298
Community Relations	$ 19,767	$ 8,053	-$ 4,705	$ 13,355	$ 13,927	$ 14,345
Administrative & General Expense	$ 921,831	$ 741,765	$ 806,924	$ 1,019,724	$ 1,047,829	$ 1,281,489
Total OMN&A	**$ 2,095,420**	**$ 1,884,617**	**$ 1,855,224**	**$ 2,099,690**	**$ 2,449,126**	**$ 3,067,314**
Year by Year Increase		-0.02	-1.58%	11.64%	14.27%	20.15%
Compound Annual Growth Rate from 2008 Approved						10%
Compound Annual Growth Rate from 2008 Actual						13%
Inflation Rate Canada CPI		2.4%	0.3%	1.8%	3.0%	3.0%

*2011 and 2012 Inflation Rate of 3.0% based on average between January – June 2011 Canada CPI from www.statcan.gc.ca and http://www.bankofcanada.ca/

Table 4.1 Summary OM&A Expense Variances 2008 Approved vs. 2008 Actual

OM&A: 2008 Approved vs. 2008 Actual				
Description	**2008 Approved**	**2008 Actual**	**Variance $**	**Variance %**
Operations	$620,871	$617,177	-$3,694	-0.6%
Maintenance	$104,107	$77,337	-$26,770	-25.7%
Billing & Collecting	$428,844	$440,285	$11,441	2.7%
Community Relations	$19,767	$8,053	-$11,714	-59.3%
Administrative & General Expense	$921,831	$741,765	-$180,066	-19.5%
Total OM&A Expense	**$2,095,420**	**$1,884,617**	**-$210,803**	**-10.1%**

Table 4.2 Summary OM&A Expense Variances 2008 Actual vs. 2009 Actual

OM&A: 2008 Actual vs. 2009 Actual				
Description	**2008 Actual**	**2009 Actual**	**Variance $**	**Variance %**
Operations	$617,177	$505,675	-$111,502	-18.1%
Maintenance	$77,337	$139,615	$62,278	80.5%
Billing & Collecting	$440,285	$407,715	-$32,570	-7.4%
Community Relations	$8,053	-$4,705	-$12,758	-158.4%
Administrative & General Expense	$741,765	$806,924	$65,158	8.8%
Total OM&A Expense	**$1,884,617**	**$1,855,224**	**-$29,394**	**-1.6%**

Table 4.3 Summary OM&A Expense Variances 2009 Actual vs. 2010 Actual

OM&A: 2010 Actual vs. 2011 Bridge Year				
Description	**2010 Actual**	**2011 Bridge**	**Variance $**	**Variance %**
Operations	$415,821	$579,609	$163,788	39.4%
Maintenance	$225,312	$306,219	$80,907	35.9%
Billing & Collecting	$425,479	$501,542	$76,063	17.9%
Community Relations	$13,355	$13,927	$572	4.3%
Administrative & General Expense	$1,019,724	$1,047,829	$28,105	2.8%
Total OM&A Expense	**$2,099,690**	**$2,449,126**	**$349,436**	16.6%

Table 4.4 Summary OM&A Expense Variances 2010 Actual vs. 2011 Bridge Year

OM&A: 2010 Actual vs. 2011 Bridge Year				
Description	**2010 Actual**	**2011 Bridge**	**Variance $**	**Variance %**
Operations	$415,821	$579,609	$163,788	39.4%
Maintenance	$225,312	$306,219	$80,907	35.9%
Billing & Collecting	$425,479	$501,542	$76,063	17.9%
Community Relations	$13,355	$13,927	$572	4.3%
Administrative & General Expense	$1,019,724	$1,047,829	$28,105	2.8%
Total OM&A Expense	**$2,099,690**	**$2,449,126**	**$349,436**	16.6%

Table 4.5 Summary OM&A Expense Variances 2011 Bridge Year vs. 2012 Test Year

OM&A: 2011 Bridge Year vs. 2012 Test Year				
Description	**2011 Bridge**	**2012 Test**	**Variance $**	**Variance %**
Operations	$579,609	$879,396	$299,787	51.7%
Maintenance	$306,219	$391,786	$85,567	27.9%
Billing & Collecting	$501,542	$500,298	-$1,244	-0.2%
Community Relations	$13,927	$14,345	$418	3.0%
Administrative & General Expense	$1,047,829	$1,281,489	$233,660	22.3%
Total OM&A Expense	**$2,449,126**	**$3,067,314**	**$618,188**	**25.2%**

Table 4.6 Additional Total OM&A Expense Comparative Information Table

Required Total OM&A Comparison	**Variance**	**%**
Test Year vs. 2008 Actual	$1,182,696	39%
Test Year vs. 2008 Approved	$971,894	32%
Test Year vs. 2009 Actual	$1,212,090	40%
Test Year vs. 2010 Actual	$967,623	32%
Simple Average Variance % for all Actual Years	$1,083,576	35%
Compound Annual Growth rate for actual years		13%

For comparison purposes LUI has provided Table 4.7 which compares the cost per customer of LUI to the LDCs in its top 20 cohort which are comparable in population served customer size as

indicated by the 2008 PEG report. The operating, maintenance and administrative expenses and customer records are pulled from the reported figures in the 2010 OEB Yearbook. The 2010 OM&A Expenses includes taxes other than income whereas the analysis above does not include taxes, however once the above tables include taxes all reports are equaling.

Table 4.7 – Cost per Customer Comparison

Comparable Utilities	Lakefront Utilities	Hydro Hawkesbury Inc.	Renfrew Hydro Inc.	Parry Sound Power Corporation	E.L.K Energy Inc.	Norfolk Power Distribution
Efficiency Ranking	**3**	**1**	**2**	**12**	**14**	**20**
Population Served	**22000**	**10500**	**7846**	**6500**	**21873**	**31500**
Residential Customers	8369	4817	3654	2773	9899	16769
General Service < 50kW Customers	1069	593	442	538	1187	2009
General Service > 50kW Customers	133	86	59	66	119	162
B) Total Customers	**9571**	**5496**	**4155**	**3377**	**11205**	**18940**
Expenses						
Operating	$ 415,821	$ 75,104	$ 206,387	$ 198,937	$ 236,550	$ 1,106,741
Maintenance	$ 225,312	$ 131,509	$ 145,465	$ 163,008	$ 310,300	$ 1,115,511
Administrative	$ 1,458,558	$ 661,075	$ 680,569	$ 679,154	$ 1,536,447	$ 2,696,758
Other	$ 46,698	$ 15,678	$ -	$ -	$ 31,759	$ 74,556
A)Total OM&A Expenses	**$ 2,146,389**	**$ 883,366**	**$ 1,032,421**	**$ 1,041,099**	**$ 2,115,056**	**$ 4,993,566**
C) OM&A Per Customer C) = A)/B)	**$ 224**	**$ 161**	**$ 248**	**$ 308**	**$ 189**	**$ 264**

Detailed information with respect to OM&A costs and variances, arranged by USoA account, is provided in this Exhibit 4.

The variance used to determine the OM&A accounts requiring analysis has been prescribed by the Filing Requirements as 0.5% of distribution revenue for distributor's with distribution revenue less than or equal to $10 million. LUI has a revenue requirement less than $ 10 million and is required to use $50,000 as the default materiality threshold. As the threshold will not always capture all variances needing explanation LUI will provide additional analysis to the accounts that require input and forecast explanation.

Table 4.8 Materiality Threshold

Description	2008 Actual	2008 Board Approved	2009 Actual	2010 Actual	2011 Bridge Year	2012 Fwd Test Year
Distribution Revenue Requirement	$3,717,998	$3,985,246	$4,005,725	$4,010,859	$3,966,786	$4,725,887
Materiality (Below $10M)	$18,590	$19,926	$20,029	$20,054	$19,834	$23,629

As indicated in Table 4.8 the lowest materiality limit during the past 4 years is $ $18,590 for LUI. To ensure a thorough analysis LUI has provided analysis of all variances greater than $20,000, or as mentioned above, to the accounts requiring further analysis explanation where there may be question.

OM&A COSTS

OM&A costs in this Exhibit represent LUI's integrated set of asset maintenance and customer service activity 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 costs to provide services to customers connected to LUI'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 2012 Test Year are the result of a business planning and work prioritization process that ensures that the most appropriate, cost effective solutions are put in place. LUI strives to make sound and efficient business decisions while maintaining perspective for opportunities in the future.

LUI is proposing recovery of 2012 Test Year OM&A costs, excluding amortization, PILs and interest totaling $ **3,067,314**. Including the amount of $ 49,542 taxes other than income taxes the total distribution expenses LUI is proposing to recovery for 2012 Test Year

is $ 3,116,856 . Please see the chart for break down of the OM&A expenses for 2012 Test Year.

WORKING CAPITAL ALLOWANCE FOR 2012

Distribution Expenses	
Distribution Expenses - Operation	879,396
Distribution Expenses - Maintenance	391,786
Billing and Collecting	500,298
Community Relations	14,345
Administrative and General Expenses	1,281,489
Taxes Other than Income Taxes	49,542
Less: Capital Taxes within 6105	
Total Eligible Distribution Expenses	**3,116,856**
Power Supply Expenses	23,056,611
Total Working Capital Expenses	26,173,467
Working Capital Allowance rate of 15%	3,926,020

OM&A BUDGETING PROCESS USED BY LUI

The operating budget is prepared annually by management and is reviewed and approved by LUI's Board of Directors. The budget is prepared before the start of each fiscal year, and provides an initial plan and mapping against which actual results may be evaluated. Once approved the budget is only revised if a material change in plan is required.

Operating Work plans

The Department Managers provide input for the preparation of the departmental budget. The following directives are provided to each manager and director:

- Outside expenses for 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 headcount of the department for accuracy and outline any changes;
- Accounting prepares a total labour budget by department using projected wage and benefit cost. 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

LUI 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, Appendix C for further tax calculations and a copy of the 2010 Federal T2 return.

DEPARTMENTAL AND CORPORATE OM&A ACTIVITIES

Operations and Maintenance

The expenses for this department include all costs relating to the operation (5000-5095) and maintenance (5105-5195) of LUI'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, Technical Services and Stores in the most cost efficient manner. LUI'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).

LUI's customer responsiveness and system reliability are monitored and documented continually to ensure that LUI's maintenance strategy is effective. This effort is coordinated with LUI's ongoing capital project work so that when maintenance programs identify capital upgrades LUI can adjust its capital spending priorities accordingly.

Predictive Maintenance

Predictive maintenance activities involve the testing of elements of the LUI distribution system. These activities include infrared thermography testing, transformer oil analysis, planned visual equipment inspections, and pole testing. These evaluation tools are all administered using a grid system with appropriate frequency levels. Evaluation is performed using a cyclical maintenance cycle of all areas that LUI preserves. Any identified deficiencies found are prioritized and addressed within a suitable time frame.

Preventative Maintenance

Preventative maintenance activities include inspection, servicing, repair of network components and regularly scheduled tree trimming. This includes overhead and pad-mounted load break switch maintenance and regular inspection and repair of substation components and ancillary equipment. The work is scheduled based on the frequency of use and a combination of time and condition based methodologies. For tree trimming, LUI's distribution service territory is divided into 3 quadrants. Each quadrant is trimmed on a three year schedule.

Emergency Maintenance

Emergency Maintenance includes unexpected system repairs to the electrical distribution system that must be addressed immediately. The costs include those related to repairs caused by storm damage, equipment failure, emergency tree trimming and on-call premiums. LUI maintains an outage data base and constantly evaluates the outage data

to adapt its predictive and preventative maintenance actions. The ultimate objective is to prevent or greatly reduce the requirement for emergency maintenance. An answering service company has been contracted to contact "standby" 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 LUI 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

LUI is in the process of installing a SCADA (Supervisory Control and Data Acquisition) system in its 27.6kV stations and at its wholesale metering points. Communication and Network operating costs are to be charged to account 5085.

Metering

The LUI metering department is responsible for the installation, testing, and commissioning of all 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.

Metering is accountable for smart meter processes that ensure LUI's smart meter system is performing as required and that the meters are measuring accurately and communicating daily with the IESO. With the installation of Smart Meters, LUI's operational expenses include MDMR, AMI and ODI costs.

Revenue Protection is another key activity performed by Metering, by proactively investigating potential diversion and theft of power. Metering is developing processes using the smart meter system to compare the totalized consumptions of the electric services connected to the distribution transformer with the consumption recorded at the distribution transformer.

Substation Services

Substation services activities address the maintenance of all equipment at LUI's 7 substations. This includes both labour costs and non-capital material spending to support both scheduled and emergency maintenance events. As with the maintenance activities, LUI's substation maintenance strategy focuses on minimizing, to the extent possible, emergency-type work by improving the effectiveness of LUI's planned maintenance program (including predictive and preventative actions) for its substations.

Technical Services Department

In 2012 the Technical Services department will be responsible for keeping asset related data up to date on an electronic Geographic Information System ("GIS") and proposed Supervisory Control and Data Acquisition (SCADA). The GIS system is used for asset management activities, troubleshooting system problems, delivering underground utility locating services for excavating contractors and for design and construction activities including new capital projects and customer connections. Technical Services will also implement and manage the proposed SCADA system. Technical Services also delivers the designs for capital projects and provides distribution system asset information to many departments within LUI. Technical Services 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 and adjusted if required 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 LUI's operations. This would include monitoring inventory levels, issuing material receipts, material issues, and material returns as required.

Garage/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 hourly cost/hr is set for all vehicles within the fleet. Costs are adjusted to actual at year end.

Labour Burden/Health and Safety

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 based on direct labour. An overhead rate is set at the beginning of each year and adjusted if required to actual at year end.

In addition, the cost of Health and Safety is included in this department. Costs include Health & Safety program supplies as well labour costs associated with safety meetings. LUI is committed to maximizing productivity and reducing risk of injury by initiating health and safety measures that focus on preventative actions. LUI's commitment to health and safety 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. LUI recently achieved the milestone of

380,000 hours without a loss-time incident and continues to record hours on its path to achieving its next health and safety milestone. LUI continuously enrolls its staff in training and development to keep consistency and ahead of a constantly changing work environment. LUI also pays close attention to its succession planning.

Customer Service

The Customer Service group is responsible for the customer care activities for the approximately 9,800 customers in LUI's service area. These activities include meter reading TOU, billing enquiries, call center, collections, and other back office functions. LUI aspires to achieve customer service excellence in its processes and customer programs. The costs associated with the Customer Service department are collected in accounts 5305 to 5340.

Meter Reading

Meter reading services are contracted out to a non-affiliated third party under a service contract agreement. On average the contractor reads approx. 5,000 electric service meters per month as of preparation of this application. The current meter reading contract was negotiated in January 2011. The agreement now operates as in the yearlong contractual terms. This cost is forecasted to dissipate following successful integration of the Smart Metering in LUI's area.

Billing

LUI performs monthly and bi-monthly billings and issues approximately 68,000 electricity invoices annually to customers. On average this total includes 135 final bills monthly for customers moving within or outside of LUI's service territory. An annual billing schedule is created based on the meter reading schedule to ensure timely billing of services. The

billing functions include the VEE processes; EBT and retailer settlement functions for over 1,300 retailer accounts; account adjustments; processing meter changes; and other various account related field service orders and mailing services. LUI offers customers a number of billing and payment options including walk-in counter service, arrears management, 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, LUI 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 and inactive account collections are turned over to a collection agency after collection methods are exhausted.

Community Relations

LUI is committed to providing consumer information and responses, in a timely and proactive manner, on electricity distribution and related issues. LUI maintains a presence in the communities it serves, where LUI staff is available to answer customer questions in a friendly environment. Since LDCs are the "face-to-the-customer" for the electricity industry, LUI has an important role to play in educating the public about electricity safety and energy conservation. LUI participates actively in the prescribed OPA conservation and demand programs administering the majority of the programs utilizing LUI staff. LUI is very active in the community promoting conservation initiatives, attending a number of community events each year and distributing energy conservation handouts and OPA coupons. These activities are expected to increase over the years to include Town Hall meetings for both transparency and the aggressive promotion and marketing of our CDM initiatives.

ADMINISTRATIVE AND GENERAL EXPENSES

Administrative and general expenses include expenses incurred in connection with the general administration of the utility's operations. Within LUI, 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);
- Management Salaries and Expenses (5610);
- Finance and Administrative Services (5615);

Executive Salaries and Expenses: 5605

This account includes expenses for Executive Management including salaries and related expenses. Consistent with Section 2.7.4 of the June 12,2011 Ontario Energy Board Chapter Two of the Filing Requirements which states, “Where there are three or fewer employees in any category, the applicant should aggregate this category with the category to which it is most closely related. This higher level of aggregation should be continued, if required, to ensure that no category contains three or fewer employees.” LUI has aggregated account 5605 with account 5615 and will show expenses and salaries in 5605 recorded into 5615. The expenses that are incurred in this account are solely for the directors fees.

Management Salaries and Expenses: 5610

This account incurs the expenses for Management including salaries and related expenses.

Administrative Services: 5615

Administrative Services is comprised of several sub-accounts: 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 CGAAP and OEB reporting requirements; 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 PILS compliance. The department is also responsible for all regulatory reporting and compliance with applicable codes and legislation governing LUI including development and preparation of rate filings, performance reporting, and compliance.

The 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 Accounting Supervisor, Financial & Regulatory Analyst, Accounts Payable Clerk, Accounts Receivable Clerk, and the Administrative Assistant, as well as incidental expenses relating to corporate services support and human resource support.

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. This also includes the supervision fees and expenses paid under contract by LUI for general management services. To the extent of the cost of professional services that can be assigned to a particular function, activity or account. This account does not include inspection or brokerage fees and commissions that are chargeable to other accounts in connection with security issues.

Employee Post-Retirement Benefits: 5645

Employee Post-Retirement Benefits include annual expenses for post-retirement benefits provided to eligible LUI employees in accordance with company policy and as provided in the collective bargaining agreement between LUI 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 two to three years. LUI has engaged an external consultant to begin the work required to prepare LUI's actuarial valuation. LUI's next actuarial report expected to be completed early 2012, for the year end December 31, 2011.

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.

Maintenance of General Plant: 5675

Expenses under Maintenance of General Plant include all costs of operating the service center 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. Membership dues and other miscellaneous association fee costs are included in this account. LUI is a member of the Electrical Distributor Association and the Cornerstone Hydro Electric Concepts. CHEC has a membership of 12 small LDCs and through LUI's association with the CHEC group LUI has worked together to reduce costs, and share resources. LUI has worked together on common 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 the implementation of IFRS and the Cost of Service Rate Applications.

LUI Account by Account Details

Table 4.9 Detailed Account by Account Operation Expenses

USoA	Distribution Expenses	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
5005	Operation Supervision and Engineering	140,459	148,399	158,401	183,440	188,943	323,678
5010	Load Dispatching	0	0	0	0	0	0
5012	Station Buildings and Fixtures Expense	0	0	0	0	0	0
5014	Transformer Station Equipment - Operation Labour	0	0	0	0	0	0
5015	Transformer Station Equipment - Operation Supplies and Expenses	0	0	0	0	0	0
5016	Distribution Station Equipment - Operation Labour	7,686	1,314	5,211	1,043	2,523	2,599
5017	Distribution Station Equipment - Operation Supplies and Expenses	41,527	63,084	21,690	4,151	29,642	35,331
5020	Overhead Distribution Lines and Feeders - Operation Labour	260,858	223,159	153,369	160,832	178,880	309,975
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	137,134	133,540	107,960	26,977	122,488	126,163
5030	Overhead Subtransmission Feeders - Operation	0	0	0	0	0	0
5035	Overhead Distribution Transformers- Operation	1,558	2,449	0	0	0	631
5040	Underground Distribution Lines and Feeders - Operation Labour	25,467	29,339	25,509	17,498	18,023	25,000
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	3,966	15,286	25,314	17,456	19,352	19,933
5050	Underground Subtransmission Feeders - Operation	0	0	0	0	0	0
5055	Underground Distribution Transformers - Operation	0	0	0	0	0	0
5060	Street Lighting and Signal System Expense	0	0	0	0	0	0
5065	Meter Expense	0	0	0	0	15,202	31,316
5070	Customer Premises - Operation Labour	0	0	300	0	0	0
5075	Customer Premises - Materials and Expenses	0	0	0	0	0	77
5085	Miscellaneous Distribution Expense	2,216	607	7,921	4,424	4,556	4,693
5090	Underground Distribution Lines & Feeders-Rental Paid	0	0	0	0	0	0
5095	Overhead Distribution Lines and Feeders - Rental Paid	0	0	0	0	0	0
5096	Other Rent	0	0	0	0	0	0
	TOTAL OPERATING EXPENSES	**620,871**	**617,177**	**505,675**	**415,821**	**579,609**	**879,396**

Table 4.10 Detailed Account by Account Maintenance Expenses

USoA	Maintenance Expenses	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
5105	Maintenance Supervision and Engineering	0	0	0	0	34,875	52,313
5110	Maintenance of Buildings and Fixtures Distribution Stations	0	0	0	0	0	0
5112	Maintenance of Transformer Station Equipment	0	0	0	0	0	0
5114	Maintenance of Distribution Station Equipment	0	0	0	0	0	0
5120	Maintenance of Poles, Towers and Fixtures	3,124	3,033	8,375	36,678	40,570	41,787
5125	Maintenance of Overhead Conductors and Devices	0	0	0	0	0	10,000
5130	Maintenance of Overhead Services	0	0	0	0	0	3,000
5135	Overhead Distribution Lines and Feeders Right of Way	18,016	24,233	39,912	69,204	44,863	45,054
5145	Maintenance of Underground Conduit	0	0	0	0	0	0
5150	Maintenance of Underground Conductors and Devices	0	0	0	0	0	0
5155	Maintenance of Underground Services	214	1,197	9,015	8,699	8,960	9,229
5160	Maintenance of Line Transformers	65,522	35,904	42,096	30,881	35,674	36,139
5165	Maintenance of Street Lighting and Signal Systems	0	0	0	0	0	0
5170	Sentinel Lights Labour	0	0	0	0	0	0
5172	Sentinel Lights Materials and Expenses	0	0	0	0	0	0
5175	Maintenance of Meters	17,231	12,970	40,217	79,848	141,277	194,264
5178	Customer Installations Expenses Leased Property	0	0	0	0	0	0
5195	Maintenance of Other Installations on Customer Premises	0	0	0	0	0	0
	TOTAL MAINTENANCE EXPENSES	**104,107**	**77,337**	**139,615**	**225,312**	**306,219**	**391,786**

Table 4.11 Detailed Account by Account Billing & Collecting Expenses

USoA	Billing & Collecting Expenses	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
5305	Supervision	0	0	0	0	0	0
5310	Meter Reading Expense	65,533	64,970	63,778	62,890	134,191	17,192
5315	Customer Billing	122,846	122,411	129,841	126,867	130,575	131,000
5320	Collecting	97,303	97,641	92,675	103,730	106,842	130,277
5325	Collecting- Cash Over and Short	(17)	5	128	(17)	0	0
5330	Collection Charges	516	4,440	8,925	4,067	4,050	4,172
5335	Bad Debt Expense	21,344	29,693	13,290	22,681	21,888	22,545
5340	Miscellaneous Customer Accounts Expenses	121,319	121,125	99,078	105,261	103,995	195,112
	TOTAL BILLING & COLLECTING EXPENSES	**428,844**	**440,285**	**407,715**	**425,479**	**501,542**	**500,298**

Table 4.12 Detailed Account by Account Community Relations Expenses

USoA	Community Relations Expenses Operation	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
5405	Supervision	0	0	0	0	0	0
5410	Community Relations - Sundry	19,767	8,053	(4,705)	13,355	13,927	14,345
5415	Energy Conservation	0	0	0	0	0	0
5420	Community Safety Program	0	0	0	0	0	0
5510	Demonstrating and Selling Expense	0	0	0	0	0	0
5515	Advertising Expense	0	0	0	0	0	0
5520	Miscellaneous Sales Expense	0	0	0	0	0	0
	TOTAL COMMUNITY RELATIONS EXPENSES	**19,767**	**8,053**	**(4,705)**	**13,355**	**13,927**	**14,345**

Table 4.13 Detailed Account by Account General & Administrative Expenses

USoA	General & Administrative Expenses	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
5605	Executive Salaries and Expenses	17,657	16,612	33,310	46,510	47,906	49,343
5610	Management Salaries and Expenses	312,318	336,516	365,367	426,686	449,700	494,916
5615	General Administrative Salaries and Expenses	148,698	86,694	77,739	91,247	93,985	143,854
5620	Office Supplies and Expenses	93,931	77,736	95,090	99,808	102,802	105,886
5625	Adminsitrative Expense Transferred-Credit	0	0	0	0	0	0
5630	Outside Services Employed	138,624	7,309	62,428	70,228	101,364	155,405
5635	Property Insurance	19,915	20,347	24,675	27,066	27,878	28,715
5640	Injuries and Damages	39,556	48,141	48,045	58,794	60,558	62,375
5645	Employee Pensions and Benefits	0	0	0	0	0	0
5650	Franchise Requirements	0	0	0	0	0	0
5655	Regulatory Expenses	82,531	85,631	33,127	58,782	85,546	103,562
5660	General Advertising Expenses	5,025	2,050	3,486	2,213	2,583	4,660
5665	Miscellaneous General Expenses	3,524	2,450	40	0	830	855
5670	Rent	0	0	0	0	0	0
5675	Maintenance of General Plant	32,464	28,575	44,930	32,398	33,370	84,371
5680	Electrical Safety Authority Fees	27,588	29,704	40,600	53,616	41,306	47,546
5685	Independent Market Operator Fees and Penalties	0	0	0	0	0	0
5695	OM&A Contra Account	0	0	(21,913)	(53,778)	0	0
5681	Special Purpose Charge Expense	0	0	0	106,153	0	0
	TOTAL GENERAL & ADMINISTRATIVE EXPENSES	**921,831**	**741,765**	**806,924**	**1,019,724**	**1,047,829**	**1,281,489**

VARIANCE ANALYSIS ON OM&A COSTS

LUI has provided a detailed OM&A cost table covering the periods from 2008 Actual, 2008 Board Approved, 2009 Actual, 2010 Actual, 2011 Bridge Year and 2012 Test Year including the variances year over year in Exhibit 4, Tables 4.1, 4.2, 4.3, 4.4, 4.5 and 4.6 above. Before moving to a variance analysis for each account that exceeds the materiality threshold, a summary of total OM&A expenses is presented below in Table 4-16 along with an analysis of the total movement from 2008 Actual to 2012 Test Year. The operating budget is prepared annually by management and is reviewed and approved by the board of directors.

Cost Drivers Increases & Decreases

LUI has identified the incremental OM&A cost drivers in the preparation of this application, which are detailed below in Table 4.14 Cost Driver Table. While there are many cost drivers, certain items are significant enough to warrant special comment based on the increases over time. It should be noted that LUI's cost drivers have exceeded the actual OM&A cost increases year over year and it is not possible for Table 4.14 to balance completely for each year's OM&A without detailing every expense or credit. The variance has been identified in the 'Other Ad Hoc Increase/Decrease Row' to make whole the opening to closing balances. Additional calculation on the row below represents the percentage over closing balance that this category contains. Successful efforts at cost containment have allowed LUI to keep its OM&A costs under control.

Table 4.14 Cost Driver Table

		2008 Actual vs. Approved	2009 Actual	2010 Actual	2011 Bridge	2012 Test
	Cost Driver					
	Opening Balance	$ 1,942,957.00	$ 1,884,617.34	$ 1,855,223.61	$ 2,099,690.21	$ 2,449,125.85
	Distribution					
B	Third Party Services	(131,315.00)	55,119.00	7,799.74	31,136.45	54,041.28
C	Non-Union Wage Adjustments	(38,850.66)	36,593.27	88,027.67	27,147.37	96,522.72
D	Tree Trimming	6,217.00	15,679.00	29,292.25	(24,341.44)	191.12
E	Meter Maintenance	(4,261.00)	27,247.00	39,631.32	61,428.28	52,987.65
F	Meter Reading	(563.00)	(1,192.00)	(888.46)	71,301.67	(116,999.26)
G	Regulatory Fees	1,137.10	(5,174.60)	11,807.89	9,844.17	3,401.71
H	Consulting Regulatory Fees	542.48	(14,429.59)	14,925.00	16,078.28	4,379.10
I	Legal Regulatory Fees	1,544.37	(33,701.53)	(972.35)	1,414.72	10,234.60
J	Over Head Distribution Labour	(37,699.00)	(69,790.00)	7,463.22	18,047.79	131,095.40
K	Capital Maintenance	(11,058.00)	(5,687.00)	(13,298.21)	35,408.17	58,641.05
L	Collections	338.00	(4,966.00)	11,055.38	3,111.91	23,434.88
M	Software Maintenance	(194.00)	(22,047.00)	6,182.86	(1,265.64)	91,117.27
N	Bad Debts	8,349.00	(16,403.00)	9,391.10	(793.04)	656.64
	Sub Total Closing Balance	1,737,144	1,845,865	2,065,641	2,348,209	2,858,830
O	Other Ad Hoc Increase/ Decrease	147,473.05	9,358.72	34,049.19	100,916.95	208,483.66
	% Over Closing Balance	7.8%	0.5%	1.6%	4.1%	6.8%
	Closing Balance	**1,884,617**	**1,855,224**	**2,099,690**	**2,449,126**	**3,067,314**
	Inflation Rate Canada CPI	2.4%	0.3%	1.8%	3.0%	3.0%
A	Inflation / Decrease	46,631	5,842	33,394	62,991	73,474

A) Inflation

LUI has estimated inflationary increases for its OM&A budget at the rate of the yearly average posted CPI inflation. For the 2012 test year LUI used the average between January – June 2011 Bridge year rates equaling 3.0% from the Canada CPI off the websites www.statcan.gc.ca and http://www.bankofcanada.ca/ to estimate the yearly increase due to inflation. For the purposes of this cost driver application, total OM&A has been calculated by the opening balance to identify how labour increases and costing increases have gradually driven expenses upwards based on economic progression. LUI did not input this inflation cost into the cost driver table as it found that the other variances would be

misapprehended due to inflation not being previously removed from the budget prior to the segregation of expenses used to construct the cost driver table.

Year	Average Inflation Rate	Total Increase
2008	2.4%	$46,630.97
2009	0.3%	$5,975.29
2010	1.8%	$34,356.72
2011	3.0%	$64,419.77
2012	3.0%	$74,460.69

LUI is materializing this cost as added increase within the OM&A budget since it is constructed in the actual figures however will not be representing inflation as a segregated cost. To predict the future expenses in OM&A LUI has taken the into consideration a conservative 3% increase for variance analysis below for the 2011 Bridge Year , and 2012 Test Year forecasts.

B) Third Party Services

LUI utilizes a number of third party services for various activities including audit, legal, maintenance services, collection services, and disposal services. Individuals amounts fluctuate annually based on requirements each year. Full analysis below in the schedule for non-affiliate services including a summary of onetime expenses. Any 2012 expenses expected to occur on a one time only basis divided by four, and spread over the four year period. LUI also reviewed costs and reduced expenses for contractors, cleaners and elimination of certain expenses related to the meter reading of stranded meters. However it should be noted that the meter reading expenses are not eliminated entirely, LUI notices a shift in the allocation of these costs, with the addition of sync operators and smart meter uploads and monitoring. LUI is aware that in order to keep rates low, LUI must ensure costs are controlled and minimized as much as possible. LUI

has taken every effort to do this in its procurement processes with a stringent policy of RFPs and tenders for any costs that are greater than twenty five thousand dollars. LUI is continuously making changes to better cut costs, and produce quality results and seeking out all opportunities for economies of scale and shared costs.

C)Non-Union Wage Adjustments and Staffing Changes

Non Union Wages allocated to OM&A accounts reflect inflationary and progressive wage adjustments in accordance with LUI's Management compensation policy, and is one cause factor for year-to-year variance as shown in LUI's cost driver table.

Fluctuations in OM&A staffing and expenses occur in response to the increase demand of additional staff and any supplementary training and development during the year to meet business demands. Fluctuations for this employee group would be due to wage adjustments, and the number of employees in these roles. LUI's hires, retires and fires are outlined in the employee compensation and incentive plan below in Table 4-36.

D)Tree Trimming

LUI rotates it tree trimming work on a three year cycle, which is differing in size throughout its territory of two townships – Cobourg and Cramahe. The cost change year by year is characteristically representing the dissimilarities in the cycles and amount of 'ad hoc' work required in this account due to – excessive rain, storms, and other natural causes that will drive costs up and down over the years.

A notable increase in 2010 is due to the area that we trim every 3 years in Colborne region. A significant amount of work is required for this area and is expected to occur every 3 years as normal.

The increase is 2010 reflects a large decrease in the year 2011 of ($24,342) as a result of the regular maintenance performed in the cycle of 2010 vs. 2011. This is expected to continue on the same schedule every three years and a smoothing factor has been applied to evenly spread the cost over four years.

E) Meter Maintenance

In 2009 LUI was authorized by regulation to conduct Smart Metering activities. In 2008 LUI had already begun the RFP process to prepare for the 2009 approval. In 2009, meter activities were focused on the installation of new smart meters. This resulted in increases in the meter maintenance expense account of $27,247 and $39,631 in 2009 and 2010 respectively. LUI incurs the maintenance cost of the stranded meters over the years of smart metering installation and stranded meter removal. Installation was performed over the course of three years

Year – Meters Installed
2009 - 5884
2010 – 2934
2011 - 685

As of the beginning of 2011 installation of smart meters in LUI's service area has been completed and has been activated for billing. TOU billing began on June 1st, 2011 and LUI has incurred increased customer service costs due to the public inquiry and new processes. Smart Meters are driving costs up in operations and maintenance accounts due to the newly assigned costs of Kinetiq and KTI/Sensus fees needed in order for the technician to accurately operate them. KTI /Sensus was approved by PRP International Inc. Fairness Advisory Services as the number one ranking proponents in the request for proposal procurement.

Smart Metering impacts OM&A beginning in the years 2012 when the costs associated with smart meters is brought into rate base. Another cost driver concerning Smart Metering is the increase for the Test Year 2012 of $52,987 due to budgeted hiring of a certified technician to oversee the maintenance of smart metering. Hiring of this technician is in relation to the asset management and will be required to regularly test, and operate the new equipment. This increase in 5175 Meter Maintenance is offset by

the cost decreases in account 5310 Meter Reading account and they are interrelated due to the changes within the organization and industry smart metering initiatives. LUI has performed a cost benefit analysis of hiring outside consultants to oversee maintenance of smart meters and hiring a certified technician. The benefit of dollar savings of hiring a skilled technician exceeds the cost of contracting third party services in LUI's procurement policy and benefits the overall satisfaction of the consumers.

F)Meter Reading

Meter Reading is a contracted third party service that LUI employs to perform the reading of all cycle areas monthly. Meter Reading has been a decreasing cost driver of -2% each year between 2008 to 2010, however in the bridge year of 2011 this service increased by $71,302 in correlation to the other cost driver of smart metering. LUI was required to contract the verification of smart meter data and it was necessary that the meter reader recorded two full cycles of each new meter to ensure the proper operations of smart meters. For the test year 2012 LUI will not require a meter reader due to the operation of smart meters therefore costs are driven down by a forecasted amount of approximately ($116,999).

G)Regulatory Expense

The increase in regulatory expense for the 2012 Test Year is due to the costs associated with the 2012 Cost of Service Rate Application. The amount included in the revenue requirement for 2012 is $40,000 or one quarter of the projected onetime costs of $103,000 which is a conservative figure relative to other LDC Cost of Service rate application projections. Any one time costs associated with regulatory expenses has been amortized over the 4 year period that this 2012 Cost of Service Rate Application relates to. A breakdown of ongoing and one-time regulatory expense is provided further in Table 4-30.

H)Consulting Expense

LUI is a small utility with a customer base of approximately 9,800 and employee complement of 19.5 full time employees (FTEs). Due to the size of LUI's utility LUI is a member of the CHEC group, and combines resources to control expenses and utilize as well as share industry knowledge. Consulting Expenses have developed as a cost driver within LUI's budget for the same reasons as Legal Fees due to increase in regulatory reporting and other business needs of the company. Consulting Fees have driven expense increases in 2010, 2011 Bridge and 2012 Test Year. LUI saw the decrease in 2009 following the previous rate application, and expects to see the same trend within the budget over the next period.

I) Legal Regulatory Expense

During Cost of Service years LUI has incurred the costs of legal expenses that expectedly drive costs up. Following LUI's cost of service year in 2008 Legal Fees decreased in the IRM periods of 2009 and 2010 by ($33,701) and ($972) respectively. Entering the Cost of Service rate application year LUI expects to incur increases of $1,415 and a conservative $10,235 in the 2011 bridge year, and 2012 test year respectively as related to entering a cost of service application year. These costs are associated with the preparation and review of the documents that are required. The increase in regulatory procedures and proceedings has in turn caused legal fees to become cost drivers of the OM&A budget. Regulatory Fees have been segregated below in table 4.30, and forecasts are based on the previous 2008 Cost of Service fees.

J)Over Head Distribution Labour

LUI identifies the asset management program as the major cost driver in this account. In the years of 2008, and 2009 decreases were seen in this category. However due to the companion cost drivers of aging workforce and asset management focuses, LUI found it necessary to budget increases in this account for labour and materials to retain

the value and integrity of it overhead distribution. For the bridge 2011 year, LUI anticipates normal increases to this account including inflation and salary increase. In the test year 2012 LUI will execute necessary succession planning to transition employees and manage attrition issues. LUI will need to budget the overlapping period for wages and burden to replace current linemen and other staff who are nearing retirement date. LUI is conscious of its employee budgeting costs and has more than one lineman who is of retirement age and must plan accordingly to ensure employee continuity and reliability in the electric service.

K) Capital Maintenance

Capital Maintenance has become a cost driving category due to the aging of capital assets, and the maintenance that is required to keep all assets in working order. In the year 2008, 2009, and 2010 LUI saw decreases in maintenance in the budget due to the focus on capitalization, so as a result labour decreased in maintenance focus, and was directed to capital creation. However increases are due to LUI's focus on asset management and major maintenance to minimize reactive work, and preserve the useful life of LUI's buildings and equipment. Work in the 2011 bridge and 2012 test is planned to be executed such as:

- Building Maintenance – Painting, waste management, storage
- Interior – Flooring, office restructuring, ceiling repairs, air quality tests and electrical rewiring.
- Exterior – Roofing, Outside Wall repairs
- Asset- Retrofits, replacements and repairs

The increase overall amounting of $94, 050 is accountable to the updating of LUI's aging capital and maintenance required to preserve its usefulness.

Carryover of the maintenance schedule due to the back order was pushed into the 2011 year, along with LUI's plans to increase capital and adding a substation has been budgeted to resume this in the year 2011 which is accounted for however will show a slight incremental lift as it is budgeted spending to spread over four years.

L) Collections

LUI has witnessed the collections account becoming a cost driver over the past 4 years due to the economic environment and the recession in economy in 2008. A large increase in expense totalling $37,602 is seen over the years of 2010 – 2012 test years due to increases in late customer bill payments and decreases in job security.

Previously in Exhibit 3 it was noted that, the removal of a large company in LUI's distribution service area previously classified as GS> 3000-4999 has closed. The closing of this large company also took with it many locally employed people's employment. As result of these economic downfalls there has been increased demand on the collections department. Changes to customer service and collection rules mandated by the OEB and effective January 2011 are expected to increase this further.

M)Software Maintenance

Software maintenance has become a cost driver due to increases in software maintenance fees which traditionally have exceeded the inflation rate and is expected to continue. For the Test Year 2012 there is an expected driven increase cost of $91,117 since LUI will need to upgrade its current software to an updated system in order to maintain adequate and appropriate service level standards. Additional increase for the test year 2012 is the anticipated rising fees by nearly $12,000 for installation of smart metering and increased demand for LUI to utilize information about the utility for regulatory reporting purposes.

N) Bad Debts

As demonstrated Bad Debts can vary from year to year; they are strongly dependent on the economic environment. In 2008, the downturn in economy resulted in Bad Debts expense of $29,693 which was $8,349 above the board approved figure. This large figure is related to the collections increase, and is primarily resulting of loss of employment and the movement of industry such as the removal of a large company in LUI's distribution service area previously classified as GS> 3000-4999. In 2009 there was a decrease of ($16,403) over 2008 due to improved economic conditions. Changes to the economy again justified changes to customer service and collection rules mandated by the OEB and effective January 2011 are expected to increase this further.

O) Other Ad Hoc

LUI is demonstrating the dollar amount and percentage of other increases/decreases in OM&A budget due to regular operations and maintenance in this row. Correspondingly this dollar amount can represent any ad hoc work that was done, and adjusted the budget due to any one time costs incurred. The percentage represents the amount of ad hoc and reactive maintenance costs that cannot be segregated by cost driver variance in to the closing balance year by year.

VARIANCE ANALYSIS:

Consistent with the Ontario Energy Board Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 22 2011, LUI has provided variance analysis for the 2012 Test Year vs. 2008 - Last Board-Approved Rebasing Application (Actual) and between the 2012 Test Year and 2010 Actual (Most Current Actuals). LUI has reviewed the variance of each US of A account by these years to determine where explanations are necessary. And identification reference has been assigned for each variance exceeding the

threshold and an explanation of the variance is presented in the following section. As previously mentioned extra information will be provided for any accounts requiring additional analysis.

Table 4-15 Detailed Account by Account, OM&A Expense Table

Expense Description	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Operations						
5005-Operation Supervision and Engineering	140,459	148,399	158,401	183,440	188,943	323,678
5010-Load Dispatching		0	0	0	0	0
5012-Station Buildings and Fixtures Expense		0	0	0	0	0
5014-Transformer Station Equipment - Operation Labour		0	0	0	0	0
5015-Transformer Station Equipment - Operation Supplies and Expenses		0	0	0	0	0
5016-Distribution Station Equipment - Operation Labour	7,686	1,314	5,211	1,043	2,523	2,599
5017-Distribution Station Equipment - Operation Supplies and Expenses	41,527	63,084	21,690	4,151	29,642	35,331
5020-Overhead Distribution Lines and Feeders - Operation Labour	260,858	223,159	153,369	160,832	178,880	309,975
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	137,134	133,540	107,960	26,977	122,488	126,163
5030-Overhead Subtransmission Feeders - Operation		0	0	0	0	0
5035-Overhead Distribution Transformers- Operation	1,558	2,449	0	0	0	631
5040-Underground Distribution Lines and Feeders - Operation Labour	25,467	29,339	25,509	17,498	18,023	25,000
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	3,966	15,286	25,314	17,456	19,352	19,933
5050-Underground Subtransmission Feeders - Operation		0	0	0	0	0
5055-Underground Distribution Transformers - Operation		0	0	0	0	0
5060-Street Lighting and Signal System Expense		0	0	0	0	0
5065-Meter Expense		0	0	0	15,202	31,316
5070-Customer Premises - Operation Labour		0	300	0	0	0
5075-Customer Premises - Materials and Expenses		0	0	0	0	77
5085-Miscellaneous Distribution Expense	2,216	607	7,921	4,424	4,556	4,693
5090-Underground Distribution Lines & Feeders-Rental Paid		0	0	0	0	0
5095-Overhead Distribution Lines and Feeders - Rental Paid		0	0	0	0	0
5096-Other Rent		0	0	0	0	0
Sub-Total	**620,871**	**617,177**	**505,675**	**415,821**	**579,609**	**879,396**

Maintenance

5105-Maintenance Supervision and Engineering		0	0	0	34,875	52,313
5110-Maintenance of Buildings and Fixtures - Distribution Stations		0	0	0	0	0
5112-Maintenance of Transformer Station Equipment		0	0	0	0	0
5114-Maintenance of Distribution Station Equipment		0	0	0	0	0
5120-Maintenance of Poles, Towers and Fixtures	3,124	3,033	8,375	36,678	40,570	41,787
5125-Maintenance of Overhead Conductors and Devices		0	0	0	0	10,000
5130-Maintenance of Overhead Services		0	0	0	0	3,000
5135-Overhead Distribution Lines and Feeders - Right of Way	18,016	24,233	39,912	69,204	44,863	45,054
5145-Maintenance of Underground Conduit		0	0	0	0	0
5150-Maintenance of Underground Conductors and Devices		0	0	0	0	0
5155-Maintenance of Underground Services	214	1,197	9,015	8,699	8,960	9,229
5160-Maintenance of Line Transformers	65,522	35,904	42,096	30,881	35,674	36,139
5165-Maintenance of Street Lighting and Signal Systems		0	0	0	0	0
5170-Sentinel Lights - Labour		0	0	0	0	0
5172-Sentinel Lights- Materials and Expenses		0	0	0	0	0
5175-Maintenance of Meters	17,231	12,970	40,217	79,848	141,277	194,264
5178-Customer Installations Expenses - Leased Property	0	0	0	0	0	0
5195-Maintenance of Other Installations on Customer Premises		0	0	0	0	0
Sub-Total	**104,107**	**77,337**	**139,615**	**225,312**	**306,219**	**391,786**

Billing and Collections

5305-Supervision		0	0	0	0	0
5310-Meter Reading Expense	65,533	64,970	63,778	62,890	134,191	17,192
5315-Customer Billing	122,846	122,411	129,841	126,867	130,575	131,000
5320-Collecting	97,303	97,641	92,675	103,730	106,842	130,277
5325-Collecting- Cash Over and Short	(17)	5	128	(17)	0	0
5330-Collection Charges	516	4,440	8,925	4,067	4,050	4,172
5335-Bad Debt Expense	21,344	29,693	13,290	22,681	21,888	22,545
5340-Miscellaneous Customer Accounts Expenses	121,319	121,125	99,078	105,261	103,995	195,112
Sub-Total	**428,844**	**440,285**	**407,715**	**425,479**	**501,542**	**500,298**

Community Relations

5405-Supervision		0	0	0	0	0
5410-Community Relations - Sundry	19,767	8,053	(4,705)	13,355	13,927	14,345
5415-Energy Conservation	0	0	0	0	0	0
5420-Community Safety Program		0	0	0	0	0
5510-Demonstrating and Selling Expense		0	0	0	0	0
5515-Advertising Expense		0	0	0	0	0
5520-Miscellaneous Sales Expense		0	0	0	0	0
Sub-Total	**19,767**	**8,053**	**(4,705)**	**13,355**	**13,927**	**14,345**

Administrative and General Expenses						
5605-Executive Salaries and Expenses	17,657	16,612	33,310	46,510	47,906	49,343
5610-Management Salaries and Expenses	312,318	336,516	365,367	426,686	449,700	494,916
5615-General Administrative Salaries and Expenses	148,698	86,694	77,739	91,247	93,985	143,854
5620-Office Supplies and Expenses	93,931	77,736	95,090	99,808	102,802	105,886
5625-Adminsitrative Expense Transferred-Credit		0	0	0	0	0
5630-Outside Services Employed	138,624	7,309	62,428	70,228	101,364	155,405
5635-Property Insurance	19,915	20,347	24,675	27,066	27,878	28,715
5640-Liability Insurance	39,556	48,141	48,045	58,794	60,558	62,375
5645-Employee Pensions and Benefits		0	0	0	0	0
5650-Franchise Requirements		0	0	0	0	0
5655-Regulatory Expenses	82,531	85,631	33,127	58,782	85,546	103,562
5660-General Advertising Expenses	5,025	2,050	3,486	2,213	2,583	4,660
5665-Miscellaneous General Expenses	3,524	2,450	40	0	830	855
5670-Rent		0	0	0	0	0
5675-Maintenance of General Plant	32,464	28,575	44,930	32,398	33,370	84,371
5680-Electrical Safety Authority Fees	27,588	29,704	40,600	53,616	41,306	47,546
5681-Special Purposes Charge Expense		0	0	106,153	0	0
5685-Independent Market Operator Fees and Penalties		0	0	0	0	0
5695 - OM&A Contra Account		0	(21,913)	(53,778)	0	0
Sub-Total	**921,831**	**741,765**	**806,924**	**1,019,724**	**1,047,829**	**1,281,489**
Total Operating, Maintenance and Administration Expenses	**2,095,420**	**1,884,617**	**1,855,224**	**2,099,690**	**2,449,126**	**3,067,314**

Table 4-16 2008 Actual to 2012 Test Year – OM&A - Account by Account Variances Expense Table

Expense Description	2008 Actual $	2012 Test $	Variance $	Variance %
Operations				
5005-Operation Supervision and Engineering	148,399	323,678	175,279	218%
5010-Load Dispatching	0	0	0	
5012-Station Buildings and Fixtures Expense	0	0	0	
5014-Transformer Station Equipment - Operation Labour	0	0	0	
5015-Transformer Station Equipment - Operation Supplies and Expenses	0	0	0	
5016-Distribution Station Equipment - Operation Labour	1,314	2,599	1,285	198%
5017-Distribution Station Equipment - Operation Supplies and Expenses	63,084	35,331	(27,753)	56%
5020-Overhead Distribution Lines and Feeders - Operation Labour	223,159	309,975	86,816	139%
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	133,540	126,163	(7,377)	94%
5030-Overhead Subtransmission Feeders - Operation	0	0	0	
5035-Overhead Distribution Transformers- Operation	2,449	631	(1,818)	26%
5040-Underground Distribution Lines and Feeders - Operation Labour	29,339	25,000	(4,339)	**85%**
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	15,286	19,933	4,647	130%
5050-Underground Subtransmission Feeders - Operation	0	0	0	
5055-Underground Distribution Transformers - Operation	0	0	0	
5060-Street Lighting and Signal System Expense	0	0	0	
5065-Meter Expense	0	31,316	31,316	
5070-Customer Premises - Operation Labour	0	0	0	
5075-Customer Premises - Materials and Expenses	0	77	77	
5085-Miscellaneous Distribution Expense	607	4,693	4,086	773%
5090-Underground Distribution Lines & Feeders-Rental Paid	0	0	0	
5095-Overhead Distribution Lines and Feeders - Rental Paid	0	0	0	
5096-Other Rent	0	0	0	
Sub-Total	**617,177**	**879,396**	**262,219**	**142%**

Maintenance				
5105-Maintenance Supervision and Engineering	0	52,313	52,313	
5110-Maintenance of Buildings and Fixtures - Distribution Stations	0	0	0	
5112-Maintenance of Transformer Station Equipment	0	0	0	
5114-Maintenance of Distribution Station Equipment	0	0	0	
5120-Maintenance of Poles, Towers and Fixtures	3,033	41,787	38,754	1378%
5125-Maintenance of Overhead Conductors and Devices	0	10,000	10,000	
5130-Maintenance of Overhead Services	0	3,000	3,000	
5135-Overhead Distribution Lines and Feeders - Right of Way	24,233	45,054	20,821	186%
5145-Maintenance of Underground Conduit	0	0	0	
5150-Maintenance of Underground Conductors and Devices	0	0	0	
5155-Maintenance of Underground Services	1,197	9,229	8,032	771%
5160-Maintenance of Line Transformers	35,904	36,139	235	101%
5165-Maintenance of Street Lighting and Signal Systems	0	0	0	
5170-Sentinel Lights - Labour	0	0	0	
5172-Sentinel Lights- Materials and Expenses	0	0	0	
5175-Maintenance of Meters	12,970	194,264	181,294	1498%
5178-Customer Installations Expenses - Leased Property	0	0	0	
5195-Maintenance of Other Installations on Customer Premises	0	0	0	
Sub-Total	**77,337**	**391,786**	**314,449**	**507%**

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Billing and Collections				
5305-Supervision	0	0	0	
5310-Meter Reading Expense	64,970	17,192	(47,778)	26%
5315-Customer Billing	122,411	131,000	8,589	107%
5320-Collecting	97,641	130,277	32,636	133%
5325-Collecting- Cash Over and Short	5	0	(5)	0%
5330-Collection Charges	4,440	4,172	(268)	94%
5335-Bad Debt Expense	29,693	22,545	(7,148)	76%
5340-Miscellaneous Customer Accounts Expenses	121,125	195,112	73,987	161%
Sub-Total	**440,285**	**500,298**	**60,013**	**114%**

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Community Relations				
5405-Supervision	0	0	0	
5410-Community Relations - Sundry	8,053	14,345	6,292	178%
5415-Energy Conservation	0	0	0	
5420-Community Safety Program	0	0	0	
5510-Demonstrating and Selling Expense	0	0	0	
5515-Advertising Expense	0	0	0	
5520-Miscellaneous Sales Expense	0	0	0	
Sub-Total	**8,053**	**14,345**	**6,292**	**178%**
Administrative and General Expenses				
5605-Executive Salaries and Expenses	16,612	49,343	32,731	297%
5610-Management Salaries and Expenses	336,516	494,916	158,400	147%
5615-General Administrative Salaries and Expenses	86,694	143,854	57,160	166%
5620-Office Supplies and Expenses	77,736	105,886	28,150	136%
5625-Adminsitrative Expense Transferred-Credit	0	0	0	
5630-Outside Services Employed	7,309	155,405	148,096	2126%
5635-Property Insurance	20,347	28,715	8,368	141%
5640- Liability Insurance	48,141	62,375	14,234	130%
5645-Employee Pensions and Benefits	0	0	0	
5650-Franchise Requirements	0	0	0	
5655-Regulatory Expenses	85,631	103,562	17,931	121%
5660-General Advertising Expenses	2,050	4,660	2,610	227%
5665-Miscellaneous General Expenses	2,450	855	(1,595)	35%
5670-Rent	0	0	0	
5675-Maintenance of General Plant	28,575	84,371	55,796	295%
5680-Electrical Safety Authority Fees	29,704	47,546	17,842	160%
5681-Special Purposes Charge Expense	0	0	0	
5685-Independent Market Operator Fees and Penalties	0	0	0	
5695 - OM&A Contra Account	0	0	0	
Sub-Total	**741,765**	**1,281,489**	**539,724**	**173%**
Total Operating, Maintenance and Administration Expenses	**1,884,617**	**3,067,314**	**1,182,696**	**163%**

Table 4-17 2008 Actual vs. 2012 Test Year

	2008 Actual $	2012 Test	Variance $	Variance %
Operations	617,177	879,396	262,219	42%
Maintenance	77,337	391,786	314,449	407%
Billing & Collecting	440,285	500,298	60,013	14%
Community Relations	8,053	14,345	6,292	78%
Administrative and General	741,765	1,281,489	539,724	73%
Total OM&A Expenses	**1,884,617**	**3,067,314**	1,182,696	63%

Table 4-18 Operations Variance 2008 Actual vs. 2012 Test Year

Expense Description	2008 Actual	2012 Test	Variance $	Variance %
Operations				
5005-Operation Supervision and Engineering	148,399	323,678	175,279	118%
5010-Load Dispatching	0	0	0	0%
5012-Station Buildings and Fixtures Expense	0	0	0	0%
5014-Transformer Station Equipment - Operation Labour	0	0	0	0%
5015-Transformer Station Equipment - Operation Supplies and Expenses	0	0	0	0%
5016-Distribution Station Equipment - Operation Labour	1,314	2,599	1,285	98%
5017-Distribution Station Equipment - Operation Supplies and Expenses	63,084	35,331	(27,753)	-44%
5020-Overhead Distribution Lines and Feeders - Operation Labour	223,159	309,975	86,816	39%
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	133,540	126,163	(7,377)	-6%
5030-Overhead Subtransmission Feeders - Operation	0	0	0	0%
5035-Overhead Distribution Transformers- Operation	2,449	631	(1,818)	-74%
5040-Underground Distribution Lines and Feeders - Operation Labour	29,339	25,000	(4,339)	-15%
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	15,286	19,933	4,647	30%
5050-Underground Subtransmission Feeders - Operation	0	0	0	0%
5055-Underground Distribution Transformers - Operation	0	0	0	0%
5060-Street Lighting and Signal System Expense	0	0	0	0%
5065-Meter Expense	0	31,316	31,316	100%
5070-Customer Premises - Operation Labour	0	0	0	0%
5075-Customer Premises - Materials and Expenses	0	77	77	100%
5085-Miscellaneous Distribution Expense	607	4,693	4,086	673%
5090-Underground Distribution Lines & Feeders-Rental Paid	0	0	0	0%
5095-Overhead Distribution Lines and Feeders - Rental Paid	0	0	0	0%
5096-Other Rent	0	0	0	0%
Sub-Total	**617,177**	**879,396**	**262,219**	42%

Operation, Supervision, and Engineering: 5005

$ 175,279

The increase in account 5005 between the last board approved year actual 2008 and the test year 2012 is an effect of the cost drivers related to LUI's aging workforce, and increased labour costs associated with asset management planning due to aging capital assets. A notable increase of labour occurred in the year 2010 of $25,000 when LUI performed the majority of its preventative asset maintenance work.

With this implementing of the asset management protection plan the responsibility for station operation, line operation, and meter department operation increased. Installations of Smart Meters and the implementation of new policies resulted in expected increase of costs to supervision allocations. Apart from the regular increases and progression in this category, LUI's significant cost increase occurs between 2011 and 2012 of $52,831 is due to succession planning and the beneficial addition of an engineer to manage attrition issues. This engineer is to replace the foreman who is of retirement age. There will be some overlap in terms of costs in 2012, which have been accounted for

accordingly in this 2012 Cost of Service Rate Application, amortized over the four year period.

Distribution Station Equipment Supplies and Expenses : 5017

$ (27,753)

The decrease in account 5017 between the last board approved year 2008 and the test year 2012 is primarily a result of $61,600 of preventative maintenance executed during year 2008. LUI's possession of aging assets is directly associated to the preventative maintenance expenses including the testing of breakers, transformers, and setting relays. In the same year of 2008 LUI also required to switch out of its pilot lighting for all 7 sub stations. LUI performs yearly preventative maintenance of the distribution, and sub stations and in the year 2010 preventative maintenance was only partially completed due to back order of breakers, and relays. LUI was unable to perform its yearly maintenance until the delivery of these parts and expects to carry on completion in 2011. In 2010 LUI was also unable to perform its yearly oil sample test and has budgeted to resume this in the year 2011 as well showing an incremental gap. LUI has ensured that any cost savings that could be instituted into this 2012 Cost of Service Rate Application have been utilized in accordance with direction from the minister of energy.

Overhead Distribution Lines and Feeders – Operation Supplies and Expenses: 5020

$ 86,816

In Account 5020 LUI incurs the costs that are due to labour with payroll burden in operating its overhead lines from the low voltage connection in the distribution station to LUI's customers' premises. Account 5020 has increased over $86,000 primarily due to expected work for the increase in preventative maintenance of the distribution station, and the increasing demand for man power. These expenses are expected to continue as well as increase as the overhead lines age, and require more attention and

maintenance. The largest increase in the OM&A budget to this account occurs in test year 2012 to add a staff member plus burden due to attrition issues within the company. The new staff member will be required to assist in the increase demand due to the expected maintenance to aging capital and asset management initiatives. LUI believe that this will minimize the amount of reactive work in future expenses.

Meter Expense: 5065

31,316

Account 5065 incurs the costs associated with labour and materials of operation for the customer meters and associated equipment. LUI has increased by $ 31,316 due to the reallocation of one of LUI's employees from account 1556 of smart meter capital to meter expense. This cost is required for smart metering operations and the supervision of all clerical work and associated documentation and organization of processes.

Table 4-19 Maintenance Variance 2008 Actual vs. 2012 Test

Maintenance	2008 Actual	2012 Test	Variance $	Variance %
5105-Maintenance Supervision and Engineering	0	52,313	52,313	100%
5110-Maintenance of Buildings and Fixtures - Distribution Stations	0	0	0	0%
5112-Maintenance of Transformer Station Equipment	0	0	0	0%
5114-Maintenance of Distribution Station Equipment	0	0	0	0%
5120-Maintenance of Poles, Towers and Fixtures	3,033	41,787	38,754	1278%
5125-Maintenance of Overhead Conductors and Devices	0	10,000	10,000	100%
5130-Maintenance of Overhead Services	0	3,000	3,000	100%
5135-Overhead Distribution Lines and Feeders - Right of Way	24,233	45,054	20,821	86%
5145-Maintenance of Underground Conduit	0	0	0	0%
5150-Maintenance of Underground Conductors and Devices	0	0	0	0%
5155-Maintenance of Underground Services	1,197	9,229	8,032	671%
5160-Maintenance of Line Transformers	35,904	36,139	235	1%
5165-Maintenance of Street Lighting and Signal Systems	0	0	0	0%
5170-Sentinel Lights - Labour	0	0	0	0%
5172-Sentinel Lights- Materials and Expenses	0	0	0	0%
5175-Maintenance of Meters	12,970	194,264	181,294	1398%
5178-Customer Installations Expenses - Leased Property	0	0	0	0%
5195-Maintenance of Other Installations on Customer Premises	0	0	0	0%
Sub-Total	**77,337**	**391,786**	**314,449**	407%

Maintenance Supervision and Engineering: 5105

$ 52,313

LUI has determined a need for additional maintenance technicians due to the increased responsibility and expansion of our capital. LUI requires the regular use of personnel responsible for electric distribution and metering to ensure that all of the LDC metering is functioning accurately in the system. LUI requires the technician to be responsible for installing new complex metering systems when required, and for installing customer voltage monitoring. This addition is required to maintain adequate LDC operation and customer service levels. LUI has analyzed the costs against the benefits of this addition and has selected this addition as the best course of action.

Maintenance of Poles Towers and Fixtures: 5120

$ 38,754

LUI performs maintenance of all of its poles, towers and fixtures in account 5120 based on a three year cycle. The increase in 2010 costs reflects pole testing and the preventative maintenance costs to avoid any emergency reactive expenses and is expected to occur again in 2012. A pole testing program as described in the Asset Management Strategy, details the program whereby LUI principally tests its 3200 of poles each year and thoroughly evaluates the poles on a three year schedule. This cost is spread over a 4 year budget taking into consideration the cost driver of inflation yearly.

Overhead Distribution Lines and Feeders: 5135

$ 20,821

Account 5135 incurs the expenses that are in connection with tree trimming, brush clearing etc., and other costs incurred maintaining the right of way subsequent to the construction of LUI's lines. The increase of $ 20,821 between the last board approved year actual 2008 and the test year 2012 is in direct correlation to the forestry

maintenance work that LUI rotates in our area on a cyclical basis throughout its territories as well as includes ad hoc work that is required each year. The change year over year is typically representing the differences in the cycle and the amount of ad hoc work required. A notable increase in 2010 is due to the area that LUI trims every 3 years in Colborne region. A significant amount of work is required for this area and is expected to occur every 3 years as per schedule, and the next expected date being 2013 for this particular area. Also note that there have been reactive costs in this category due to wind storms and overgrowth that need emergency attention. It was noted that our actuals have consistently exceeded Board Approved which indicated a need for increased approval in the 2012 Cost of Service Rate Application.

Maintenance of Meters: 5175

$ 181,294

Account 5175 incurs the expense of meter maintenance and meter testing of equipment. This cost includes the cleaning, and analysis work necessary to keep the equipment in service. Notable increases in this account are overstated due to the initial start-up costs in 2008 incurred as the procurement of materials, and appropriate costs related to smart metering training. Year after year the increases are identified as being due to the growth of the smart metering program and implementation as consistent with other LDC's. The largest increase is occurring between 2010 and 2011 in the installation/introduction period of development. LUI by the end of 2010 had installed 98% of all its meters in service area – as detailed below in Exhibit 9.

LUI has identified that with the implementing of Smart Metering and TOU in our region, our responsibilities, and operations are increasing in demand and LUI requires a Meter Data Agent (MDA) so that LUI is able to efficiently process and maintain the Smart Metering Program. A notable cost to the operations of this account is also due to the repair of faulty meters that needed to be reinstalled. LUI has analyzed the cost benefit in this scenario for adding an FTE for MDA. LUI has arrived at the conclusion to ensure

cost savings on third party maintenance that the LDC requires this additional person to maintain service reliability. As well, the increase in this cost is offset by the reduction in costs associated with meter reading specifically attributable to Smart Meters, as per all 5310 analyses further in Exhibit 4. It should be noted that LUI sees a large decrease in account 5310, due to the costs being reallocated to the 5175 account.

Table 4-20 Billing and Collecting Variance 2008 Actual vs. 2012 Test

Billing and Collections	2008 Actual	2012 Test	Variance $	Variance %
5305-Supervision	0	0	0	0%
5310-Meter Reading Expense	64,970	17,192	(47,778)	-74%
5315-Customer Billing	122,411	131,000	8,589	7%
5320-Collecting	97,641	130,277	32,636	33%
5325-Collecting- Cash Over and Short	5	0	(5)	-100%
5330-Collection Charges	4,440	4,172	(268)	-6%
5335-Bad Debt Expense	29,693	22,545	(7,148)	-24%
5340-Miscellaneous Customer Accounts Expenses	121,125	195,112	73,987	61%
Sub-Total	**440,285**	**500,298**	**60,013**	14%

Meter Reading Expense: 5310

(47,778)

Account 5310 decreases in expenses due to the cessation of meter reading and the implementation of Smart Meters. Although there is a decrease in expense in this account of $47,778 there is a counter balancing expense in 5175 as LUI plans to hire a Smart MDA metering Technician for the responsibility of operations. LUI expects the benefits to outweigh the costs in the acquisition of this technician. See more detailed information on the costs associated with meter reading/meter maintenance in 5175 account above.

Collecting: 5320

$ 32,636

Account 5320 incurs LUI's related cost to the collection of its customer accounts. These costs include the salaries and wages with payroll burden, legal fees and other expenses related to the collecting office for LUI. A notable increase to this salary account between 2008 actual and the 2012 test year is due to additional staff hired in collections as detailed in schedule Change in Employee Compensation & Benefits below. Year after year changes in compensation and benefits show instances of employee compliment, base wage increases, situational overtime and benefits by employee can account for the increases in this account of $18,530.

Additionally, increase demand of customer service representation expenses have been budgeted to handle the anticipated increase in call volume due to the introduction of Time of Use billing in 2011.

Table 4-21 Community Relations Variance 2008 Actual vs. 2012 Test

Community Relations	2008 Actual	2012 Test	Variance $	Variance %
5405-Supervision	0	0	0	0%
5410-Community Relations - Sundry	8,053	14,345	6,292	78%
5415-Energy Conservation	0	0	0	0%
5420-Community Safety Program	0	0	0	0%
5510-Demonstrating and Selling Expense	0	0	0	0%
5515-Advertising Expense	0	0	0	0%
5520-Miscellaneous Sales Expense	0	0	0	0%
Sub-Total	**8,053**	**14,345**	**6,292**	78%

Community Relations – Sundry: 5410

$ 6,292

LUI's employees directly engage in providing services to the community, and LUI also provides assistance to services acquired outside the organization. 5410 is the account that incurs the cost of material and expenses in carrying out community benefiting functions. These costs are necessary to inform customers of all the new changes in industry and at our utility including smart meters and TOU pricing. The largest notable

increase occurred in 2010 related to advertisement of Conservation Demand Management and Green Initiatives. A yearly occurrence of supporting the Winter Warmth Program is variable by approx. $5000/ calendar year.

Table 4-22 Administrative and General Variance 2008 Actual vs. 2012 Test

Administrative and General Expenses	2008 Actual	2012 Test	Variance $	Variance %
5605-Executive Salaries and Expenses	16,612	49,343	32,731	197%
5610-Management Salaries and Expenses	336,516	494,916	158,400	47%
5615-General Administrative Salaries and Expenses	86,694	143,854	57,160	66%
5620-Office Supplies and Expenses	77,736	105,886	28,150	36%
5625-Adminsitrative Expense Transferred-Credit	0	0	0	0%
5630-Outside Services Employed	7,309	155,405	148,096	2026%
5635-Property Insurance	20,347	28,715	8,368	41%
5640-Injuries and Damages	48,141	62,375	14,234	30%
5645-Employee Pensions and Benefits	0	0	0	0%
5650-Franchise Requirements	0	0	0	0%
5655-Regulatory Expenses	85,631	103,562	17,931	21%
5660-General Advertising Expenses	2,050	4,660	2,610	127%
5665-Miscellaneous General Expenses	2,450	855	(1,595)	-65%
5670-Rent	0	0	0	0%
5675-Maintenance of General Plant	28,575	84,371	55,796	195%
5680-Electrical Safety Authority Fees	29,704	47,546	17,842	60%
5681-Special Purposes Charge Expense	0	0	0	0%
5685-Independent Market Operator Fees and Penalties	0	0	0	0%
5695 - OM&A Contra Account	0	0	0	0%
Sub-Total	**741,765**	**1,281,489**	539,724	73%

Executive Salaries and Expenses: 5605

$ 32,731

Three members currently occupy LUI's board of directors where account 5605 incurs the salaries and expenses of the board members, president, vice-president, of LUIs organization. Major increases in this account are due to the cost driver inflation, and the increase of meetings scheduled during the transition of presidency within the organization. Due to the change in presidency there is increased focus on internal controls and updating of out-dated policies, this process principally includes the board's decision making. The largest increase in account 5605 was between the year 2008 and 2009 and this is principally due to EDA fees and seminars on smart grid that were required for the executives and board of directors to attend. It is expected that the board will stay consistent with scheduled meetings and LUI has applied inflation to the forecast for capturing purposes.

Management Salaries and Expenses: 5610

$ 158,400

LUI incurs the salary, burden and expenses to the management of its employees in account 5610. A notable increase to this salary account between 2008 actual and the 2012 test year is due to additional staff hired in operations and finance departments as detailed in schedule Change in Employee Compensation & Benefits below. Notable acquisition in the Management category includes the hiring of a Chartered Accountant of which 50% of wages and burden are allocated to LUI and the addition of Vice President of Operations as full 100% allocation to LUI. A notable change between 2008 and 2012 was the change of president in the organization. Transitional costs were incurred to this account for the overlapping of this organizational leadership change.

General Administrative Salaries and Expenses: 5615

$ 57,160

The significant costs between 2008 and 2012 that primarily contributed to the variance in account 5615 were incurred were in 2009-2010. These costs are due to an addition in staff in the Finance department of a Financial Analyst for regulatory and financial reporting purposes and also an addition of an Administrative Assistant in Human Resources Department. These increases are reflecting the wages and burden and progression in salary. Variable costs incurred in this account are the administrative students that are hired to cover vacation this varies between one to three hires a year in the summer months. The two new hires have been involved in some specific professional development and training. The costs associated with these training programs and courses has been included in this account.

Office Supplies and Expenses: 5620

$ 28,150

Account 5620 incurs the expense cost of all office supplies and fees related to the daily operations of the business. The major cost increases to this account are the increase of inflation, and increasing demand of operations. Analysis of this account shows that between 2008 and 2009 there was an increase of $17, 354 and the biggest cost drivers were the additions of:

- LUI's Billing Application Service Provider
- Increasing base costs of Canada Post
- Phone operating systems
- Yellow Pages and Promotion expenses
- Bell Mobile Services
- Safety Incentive Maintenance Expense
- Answering Services Increase

Further Analysis for the year 2010 shows these increased 2009 costs as reoccurring expenses with slight increases due to inflation in prices. Test Year 2012 is forecasted using the actual costs in 2011 and adding the cost driving inflation factor.

Outside Service Employed: 5630

$ 148,096

LUI uses third party services and professional consultants for general services which are not applicable to any particular operation function or to other accounts. The significant costs between year 2008 and 2012 that primarily contribute to the variance in account 5630 at LUI are due to:

- An over accrual in 2007, for audit fees that was corrected in 2008 that resulted in a significant decrease of 2008 Audit Fee. Audit Fees have increased by $69,038 due to transition for IFRS from CGAAP and multiplying requirements of reporting.
- Fees Associated with Actuarial Reporting are reported in this account, and are appropriated over the course of four years.
- IFRS fees were incurred beginning in 2009 when LUI was advised of direction to implement IFRS. LUI as other utilities incurred the expense of initial set up costs, and expenses related to conferences and outside services. In 2010 IFRS was deferred in delivery and held off to prepare for the year of comparable statements. Fees related to IFRS have since, increased by $10,200.

Additional expenses in this account are incurred for the use of professional services such as consulting of staff profiling, policy creation, and pay equity. LUI has also performed business assessments through a cost effective MBA case study to produce improvement suggestions within LUI's work environment. Notable increases occurred between 2008 and 2009 due to the occurrence of Cost of Service year, for legal fees, and consulting services and are expected to be incurred during the 2012 IFRS Cost of Service Rate Application implementation process. LUI attributes these types of expenses to the lack of specialized regular duty staff.

Maintenance of General Plant: 5675

$ 55,796

Account 5675 incurs the cost to general functions of labour, materials and expenses in which it is related to the maintenance of property and assets. The increase of $ 51, 973 is a result of updating of LUI's aging capital and maintenance most of which is

specifically related to the maintenance required to LUI's buildings. Maintenance is required to preserve the buildings usefulness and for preventative actions against any failures in the office. Notable increases in this account are due to;

- Updating the main office electrical framework in 2010.
- Improving air quality to the amount of $4900 installing an efficient cooling and heating system.
- Fitting the office and garage for energy efficient equipment to meet LUI's Conservation Demand Management initiatives.

The largest variance expense into this account will occur in the year 2011 and 2012 as LUI undergoes a large renovation project to its office decaying interior and exterior. LUI has begun, in 2011, performing the repair and replacement of the roofing, and reinforcement of the interior walls.

Electrical Safety Authority Fees: 5680

$ 17,842

A notable increase to account 5680 which incurs the cost of fees related to permits, inspection and tests performed for and or by the Electrical Safety Authority or the acquisition of having working professionals with designations employed within the organization. In LUI's organization there are certification fees for Certified Human Resource Professional (CHRP), Chartered Accountant (CA), and other electrical membership fees. LUI also belongs to a group of 12 small utilities called the Cornerstone Hydro Electric Concepts Association (CHEC) and pays fees each year to advantageously share resources with other utilities while reducing costs. The gradual increase in this account is also due to the inflation and increasing cost of memberships.

Regulatory Expenses: 5655

$ 17,931

Account 5655 incurs the expenses for formal cases before the Board or other regulatory bodies. Account 5655 also includes payments made to a regulatory body for fees assessed against the utility for pay and expenses of approved company. In 2010 LUI incurred the expenses of $28, 000 for Board Assessments, $6500 for legal services, $5000 for Electrical Safety Authority cost recovery, $1,000 for human resource training, $2500 for cost awards, and $12,000 to hire Consultants for Lost Revenue Adjustment Model factors. The reporting requirements of electricity have increased the amount of costs associated with regulatory reporting in LUI's industry and therefore increased fees as well. LUI is a small utility and must account for the added costs due to filing every year and performing cost of service every 4 years. This complex frame work requires many personnel and LUI is required to incur additional costs due to the requirement of consultants and mediators. Because these costs are not anticipated to decrease for the upcoming years, in 2011 LUI has applied the rate of inflation for reflecting increase. Due to the Cost of Service rate application LUI anticipates that the Test year 2012 will expand to over $200,000, the total was amortized over 4 years of the application and the 2012 Test year was increased by $50,000 yearly to allocate the costs associated with rate application. Recovery will appear in quarters until the next cost of service application.

Table 4-23 2010 ACTUAL VERSUS 2012 TEST YEAR:

	2010 Actual $	2012 Test $	Variance $	Variance %
Operations	415,821	879,396	463,575	111%
Maintenance	225,312	391,786	166,474	74%
Billing & Collecting	425,479	500,298	74,819	18%
Community Relations	13,355	14,345	990	7%
Administrative and General	1,019,724	1,281,489	261,765	26%
Total OM&A Expenses	**2,099,690**	**3,067,314**	**967,623**	**46%**

Table 4-24 Operations Variance 2010 Actual vs. 2012 Test Year

Expense Description	2010 Actual	2012 Test	Variance $	Variance %
Operations				
5005-Operation Supervision and Engineering	183,440	323,678	140,239	76%
5010-Load Dispatching	0	0	0	0%
5012-Station Buildings and Fixtures Expense	0	0	0	0%
5014-Transformer Station Equipment - Operation Labour	0	0	0	0%
5015-Transformer Station Equipment - Operation Supplies and Expenses	0	0	0	0%
5016-Distribution Station Equipment - Operation Labour	1,043	2,599	1,555	149%
5017-Distribution Station Equipment - Operation Supplies and Expenses	4,151	35,331	31,180	751%
5020-Overhead Distribution Lines and Feeders - Operation Labour	160,832	309,975	149,143	93%
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	26,977	126,163	99,185	368%
5030-Overhead Subtransmission Feeders - Operation	0	0	0	0%
5035-Overhead Distribution Transformers- Operation	0	631	631	100%
5040-Underground Distribution Lines and Feeders - Operation Labour	17,498	25,000	7,502	43%
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	17,456	19,933	2,477	14%
5050-Underground Subtransmission Feeders - Operation	0	0	0	0%
5055-Underground Distribution Transformers - Operation	0	0	0	0%
5060-Street Lighting and Signal System Expense	0	0	0	0%
5065-Meter Expense	0	31,316	31,316	100%
5070-Customer Premises - Operation Labour	0	0	0	0%
5075-Customer Premises - Materials and Expenses	0	77	77	100%
5085-Miscellaneous Distribution Expense	4,424	4,693	269	6%
5090-Underground Distribution Lines & Feeders-Rental Paid	0	0	0	0%
5095-Overhead Distribution Lines and Feeders - Rental Paid	0	0	0	0%
5096-Other Rent	0	0	0	0%
Sub-Total	**415,821**	**879,396**	**463,575**	111%

Operation, Supervision, and Engineering: 5005

$ 58,334

Direct supervision of specific activities such as station operation, line operation, meter department operation, etc. are charged to account 5005. In the year 2010 LUI had increased its spending in this account by $25,000 due to the increase of maintenance operations, and reduction to the work done for capital expenditures.

As of July 2011 LUI's charges to this account have been $ 98,296 and LUI does not anticipate additional expenses to be added to this year after year.

LUI has developed strategic succession planning for the development of LUI's capital and will be requiring a professionally accredited employee to carry out the responsibilities of daily operations. In the 2012 Test year budget LUI has added the hiring of an Engineer for the Operation and Supervision Engineering to replace the current employee that will be retiring. In the budget majority of the incurred expenses is accounted for by the increase of accreditation and overlap in training costs.

Distribution Station Equipment Supplies and Expenses : 5017

$ 31,180

Account 5017 incurs the expenses of material trucking and other expenses in operation of the transformer station equipment recorded in account 1820. In 2010 LUI's expenses for the transformer station are accountable to regular maintenance of LUI's aging assets and directly associated to the prevention of equipment failure. LUI was unable to perform the entirety of its preventative maintenance in line for the back order of breakers, and relays. Carryover of the maintenance schedule due to the back order was pushed into the 2011 year, along with LUI's yearly oil sample test and has been budgeted to resume this in the year 2011 which is accounted for however will show a slight incremental lift. As of July which is where most of the expense is incurred LUI has performed over $26,000 of maintenance and expects a regular trend of maintenance to continue with the added cost of inflation. Forecast for Test year 2012 is assuming a regular schedule of maintenance adding cost driver of inflation. One added expense in the future will be fibre connectivity to the substation.

Overhead Distribution Lines and Feeders Labour: 5020

$ 149,143

Account 5020 includes the expense of labour with payroll burden incurred in the operation of overhead lines from the low voltage connection in the distribution station to the customer's premises. In 2010 LUI performed regular maintenance labour to its overhead lines and feeders. For the 2011 year, LUI anticipated normal increases to this account including inflation and salary increase. As well it should be noted that the increasing costs can be directly ties to preventative maintenance work. LUI is scheduling preventative maintenance work in order to reduce additional costs related to emergency and reactive work.

In the test year 2012 LUI will execute necessary succession planning to transition employees and manage attrition issues due to LUI's aging workforce. LUI will need to budget the overlapping period for wages and burden to replace a current lineman who is nearing retirement date. LUI also has built into the budget the hiring of a line man apprentice of a 5 year Journeyman. The apprentice will be required to know all aspects of LUI's distribution and when fully qualified replace yet another full time lineman who will be retiring.

Overhead Distribution Lines and Feeders – Operations Supplies and Expenses: 5025

$ 99,185

Account 5025 incurs the cost of material trucking and other expenses in operating overhead lines from the low voltage connection in the distribution station to the customer's premises in relation to the labour account above. This account appears to have a large increase of $99,185 between 2010 and 2012 due to the actuals in 2010 being understated. In 2010 LUI's actual balance before credit adjustments was approx. $138,000 during the year LUI received a credit from supplier as well as an allocation of inventory to this account that was intended to be posted in another account. The total credits and over allocation was approximately $110,000.

For forecasting purposes in year 2011 LUI has used the 2008 Actual and applied a reasonable inflation rate for the year 2012 Test Year. Had the adjusted $138,000 been used in forecasting LUI would show a differential decrease in this account.

Meter Expense: 5065

$ 31,316

Account 5065 incurs the expense of operations of customer meters and associated equipment. LUI's operation in this account has increased by $31,316 due to the supervision required to operate smart meters and moved allocation that includes

the disconnecting and reconnecting process. Included in the supervisory meter expenses is the budgeted 1/3 allocation of an FTE including the added burden.

Table 4-25 Maintenance Variance 2010 Actual vs. 2012 Test

Maintenance	2010 Actual	2012 Test	Variance $	Variance %
5105-Maintenance Supervision and Engineering	0	52,313	52,313	100%
5110-Maintenance of Buildings and Fixtures - Distribution Stations	0	0	0	0%
5112-Maintenance of Transformer Station Equipment	0	0	0	0%
5114-Maintenance of Distribution Station Equipment	0	0	0	0%
5120-Maintenance of Poles, Towers and Fixtures	36,678	41,787	5,108	14%
5125-Maintenance of Overhead Conductors and Devices	0	10,000	10,000	100%
5130-Maintenance of Overhead Services	0	3,000	3,000	100%
5135-Overhead Distribution Lines and Feeders - Right of Way	69,204	45,054	(24,150)	-35%
5145-Maintenance of Underground Conduit	0	0	0	0%
5150-Maintenance of Underground Conductors and Devices	0	0	0	0%
5155-Maintenance of Underground Services	8,699	9,229	530	6%
5160-Maintenance of Line Transformers	30,881	36,139	5,257	17%
5165-Maintenance of Street Lighting and Signal Systems	0	0	0	0%
5170-Sentinel Lights - Labour	0	0	0	0%
5172-Sentinel Lights- Materials and Expenses	0	0	0	0%
5175-Maintenance of Meters	79,848	194,264	114,416	143%
5178-Customer Installations Expenses - Leased Property	0	0	0	0%
5195-Maintenance of Other Installations on Customer Premises	0	0	0	0%
Sub-Total	**225,312**	**391,786**	166,474	74%

Maintenance Supervision and Engineering: 5105

$ 52,313

Account 5105 includes the cost of labour and expenses incurred in the general supervision and direction of maintenance of the distribution system that cannot be directly allocated to any particular job/project. In the past LUI has not allocated time into this account, and in the future LUI has budgeted in succession planning to hire a technical services technician who will be required for creating required designs and service orders for new connections and service upgrades (ESA). Other responsibilities for the technician includes producing designs for new overhead capital work, capital distributions upgrades and be responsible for distribution asset management, SCADA system maintenance and FIT and micro-FIT connections. Due to the variety of responsibilities LUI will be splitting the new employees' wages and burden with account 5175.

Maintenance of Overhead Conductors and Devices: 5125

$ 10,000

Account 5125 includes the cost of labour materials used and expenses incurred in the maintenance of overhead distribution line facilities. LUI has not recorded any expenses since 2008 in this account. LUI will be performing fuse maintenance and updating the existing fuses to operate more efficiently in LUI's system. The new fuses will help reduce the reactive unplanned costs associated with to fuses being overloaded. Planned maintenance total cost is anticipated to be $40,000 when complete. For forecasting purposes in Test Year 2012 LUI has evenly spread the cost over four years to properly allocate the costs.

Overhead Distribution Lines and Feeders: 5135

$ (24,150)

LUI's Forestry maintenance work rotates in the area built on a cyclical basis of three different areas. This would include ad hoc work that is required on a demand basis each year. The change year over year is typically representing the differences in the cycle and the amount of ad hoc work required. The notable increase is in 2010 is due to the Colborne area that we labour every 3rd year. A significant amount of work is required for this area, however it is part of a trend and it is due to regularly occur every 3 years to maintain a sustainable working area. The 2012 Test Year uses an average of the cycle work spread over a four year forecasting model. Above when comparing actual vs. budget LUI noted as a large decrease of $24,150 due to the higher level of work required in Colborne on a three year cycle.

Maintenance of Meters: 5175

$ 114,416

Account 5175 incurs the expense of meter maintenance and meter testing of equipment. This cost includes the cleaning, and analysis work necessary to keep the equipment in service. Notable increases in this account are overstated due to the initial start-up costs in 2008 incurred as the procurement of materials, and introduction to smart metering training. Year after year the increases are identified as being due to the growth of the smart metering program and implementation as consistent with other LDC's. The largest increase is occurring between 2010 and 2011 in the installation/introduction period of development. This account also incurs the monthly expenses of meter fees with Kinetiq, and Sensus for the operation data storage and will continue to occur monthly.

LUI has identified that with the implementing of Smart Metering and TOU in LUI's region, our responsibilities, and operations are increasing in demand and LUI requires an (MDA) Meter Data Agent so that LUI is able to efficiently process and maintain the Smart Metering Program due to the variety of responsibilities this technician will be split with account 5105 and increases maintenance of meters by $34,875. A notable cost to the operations of this account is also due to the repair of faulty meters that needed to be reinstalled.

Table 4-26 Billing and Collecting Variance 2010 Actual vs. 2012 Test

Billing and Collections	2010 Actual	2012 Test	Variance $	Variance %
5305-Supervision	0	0	0	0%
5310-Meter Reading Expense	62,890	17,192	(45,698)	-73%
5315-Customer Billing	126,867	131,000	4,133	3%
5320-Collecting	103,730	130,277	26,547	26%
5325-Collecting- Cash Over and Short	(17)	0	17	-100%
5330-Collection Charges	4,067	4,172	105	3%
5335-Bad Debt Expense	22,681	22,545	(136)	-1%
5340-Miscellaneous Customer Accounts Expenses	105,261	195,112	89,852	85%
Sub-Total	**425,479**	**500,298**	74,819	18%

Meter Reading Expense: 5310

$ (45,698)

Account 5310 decreases in expenses due to the adjustment of meter reading process and the implementation of Smart Meters. Although there is a decrease in expense in this account of $45, 698 there is a counter balancing expense in 5175 as LUI is required to hire a Smart MDA metering Technician for the responsibility of operations. LUI expects the benefits to outweigh the costs in the acquisition of this technician. Note that the offsetting costs related to "meter reading" expense, is reallocated to meter maintenance expense, in account 5175.

Collecting: 5320

$ 26,547

Account 5320 incurs LUI's related cost to the collection of its customer accounts. These costs include the salaries and wages with payroll burden, legal fees and other expenses related to the collecting office for LUI. A notable increase to this salary account between 2008 actual and the 2012 test year is due to additional staff hired in collections as detailed in schedule Change in Employee Compensation & Benefits below. Year after year changes in compensation and benefits show instances of employee compliment, base wage increases, situational overtime and benefits by employee can account for the increases in this account additionally, increase demand of customer service representation expenses have been budgeted to handle the anticipated increase in call volume due to the introduction of Time of Use billing in 2011.

Miscellaneous Customer Accounts Expense: 5340

$ 89,852

Account 5340 includes the cost of labour, materials used and expenses incurred not provided for in other accounts. In 2010 LUI used variable pricing for its billing A.S.P and

expensed all invoicing of software support, software solutions, and monthly fees. This account increases by $89,852 between 2010 actual and 2012 when Ecaliber moved from variable pricing to fixed pricing and is also due to LUI's plans to upgrade the finance system. This will greatly improve the productivity of LUI's organization. Another added reoccurring expense will be the increase in cost for Utilismart fees by approximately $15,000 yearly. Utilismart provides settlement services for electric utilities and large users in the deregulated Ontario electricity market. Additional factors for the increase include the rate of inflation and climbing rate of fixed fees.

Table 4-27 Community Relations Variance 2010 Actual vs. 2012 Test

Community Relations	2010 Actual	2012 Test	Variance $	Variance %
5405-Supervision	0	0	0	0%
5410-Community Relations - Sundry	13,355	14,345	990	7%
5415-Energy Conservation	0	0	0	0%
5420-Community Safety Program	0	0	0	0%
5510-Demonstrating and Selling Expense	0	0	0	0%
5515-Advertising Expense	0	0	0	0%
5520-Miscellaneous Sales Expense	0	0	0	0%
Sub-Total	13,355	14,345	990	7%

Community Relations: 5410

$ 990

LUI's employees directly engage in providing services to the community, and LUI also provides assistance to services acquired outside the organization. 5410 is the account that incurs the cost of material and expenses in carrying out community benefiting functions. These costs are necessary to inform customers of all the new changes in the industry and at LUI's utility including smart meters and TOU pricing. The largest notable increase occurred in 2010 of $500 related to advertisement of Conservation Demand Management and Green Initiatives. A yearly occurrence of supporting the Winter Warmth Program is variable by approx. $5000/ calendar year. The increase between the year 2010 and the Test Year 2012 is solely accounted for by the rate of inflation.

Table 4-28 Administrative and General Variance 2010 Actual vs. 2012 Test

Administrative and General Expenses	2010 Actual	2012 Test	Variance $	Variance %
5605-Executive Salaries and Expenses	46,510	49,343	2,833	6%
5610-Management Salaries and Expenses	426,686	494,916	68,230	16%
5615-General Administrative Salaries and Expenses	91,247	143,854	52,607	58%
5620-Office Supplies and Expenses	99,808	105,886	6,078	6%
5625-Adminsitrative Expense Transferred-Credit	0	0	0	0%
5630-Outside Services Employed	70,228	155,405	85,178	121%
5635-Property Insurance	27,066	28,715	1,648	6%
5640-Injuries and Damages	58,794	62,375	3,581	6%
5645-Employee Pensions and Benefits	0	0	0	0%
5650-Franchise Requirements	0	0	0	0%
5655-Regulatory Expenses	58,782	103,562	44,780	76%
5660-General Advertising Expenses	2,213	4,660	2,448	111%
5665-Miscellaneous General Expenses	0	855	855	100%
5670-Rent	0	0	0	0%
5675-Maintenance of General Plant	32,398	84,371	51,973	160%
5680-Electrical Safety Authority Fees	53,616	47,546	(6,070)	-11%
5681-Special Purposes Charge Expense	106,153	0	(106,153)	-100%
5685-Independent Market Operator Fees and Penalties	0	0	0	0%
5695 - OM&A Contra Account	(53,778)	0	53,778	-100%
Sub-Total	**1,019,724**	**1,281,489**	**261,765**	26%

Management Salaries and Expenses: 5610

$ 68,230

LUI incurs the salary, burden and expenses to the management of its employees in account 5610. In the year 2010 additional staff was hired in this account for human resources and finance departments as detailed in schedule Change in Employee Compensation & Benefits below. Notable acquisition in the Management category includes the hiring of a Chartered Accountant as well as the addition of Vice President of Operations in 2011. A notable change occurring in this time frame was the change of president in the organization. Transitional costs were incurred to this account for the overlapping of this organizational leadership change. The increase of $44,230 is principally associated to overlapping period during the transitional period.

General Administrative Salaries and Expenses: 5615

$ 52,607

The significant costs between 2010 and 2012 that occurred were in 2010 and primarily contributed to the variance in account 5615: An increase in the Finance department of a Financial Analyst in year 2011and also hiring of a an Administrative Assistant in Human

Resources Department in the year 2010. These increases are reflecting the wages and burden and progression in salary. Variable costs incurred in this account are the administrative students that are hired to cover vacation this varies between one to three hires a year in the summer months. As there aren't any plans on movement in this account for the next rate period, increases in this account are attributable to the cost driver of inflation 3%.

Outside Services and Expenses: 5630

$ 85,178

LUI uses third party services and professional consultants for performing general services which are not applicable to a particular operation function or to other accounts. IFRS fees were incurred beginning in 2009 when LUI was required to implement IFRS. LUI as other utilities had to incur the expense of initial set up costs, and overheads related to conferences and outside services. In 2010 IFRS was again deferred in implementation. IFRS conversion and auditing fees are expected to amount to $30,000 by the test year in 2012, and the cost of transition to IFRS will amount to approx. $50,000 which is allocated over 4 years for even recovery.

LUI has recently moved to smart metering time of use billing and has budgeted to provide customers with website information. LUIs I.T department added one summer student to assist with the added task and increase of work demand. LUI anticipates having to hire third party services to complete this service. LUI budgets this service to cost approximately $20,000 in 2012.

Additionally LUI will be required to hire an outside service engineer for ¼ of test year 2012 in anticipation of LUI hiring a full time employee to perform work to LUI's capital assets. LUI has budgeted $40,000 to this account for this overlap period, and has allocated over 4 years meaning an increase of $10,000 is shown in the budget planning for test year 2012.

Notable increases occurred between 2010 and 2012 due to the occurrence of Cost of Service year, for legal fees, consulting services and similar costs are expected to be incurred during the 2011 and 2012 rate application process again. LUI attributes this type of expense to being a small utility with limited staff power to handle the increase demand.

Regulatory Expenses: 5655

$ 44,780

Account 5655 incurs the expenses for formal cases before the Board or other regulatory bodies. Account 5655 also includes payments made to a regulatory body for fees assessed against the utility for pay and expenses of approved company. In 2010 LUI incurred the expenses of $28, 000 for Board Assessments, $6500 for legal services, $5000 for Electrical Safety Authority cost recovery, $1,000 for human resource training, $2500 for cost awards, and $12,000 to hire Consultants for Lost Revenue Adjustment Model factors. The reporting requirements of electricity have increased the amount of costs associated with regulatory reporting in LUI's industry and therefore increased fees as well. LUI is a small utility and must account for the added costs due to filing every year and performing cost of service every 4 years. This complex frame work requires many personnel and LUI is required to incur additional costs due to the requirement of consultants and mediators. Because these costs are not anticipated to decrease for the upcoming years, in 2011 LUI has applied the rate of inflation for reflecting increase. Due to the Cost of Service rate application LUI anticipates that the Test year 2012 will expand to over $103,000, the total was amortized over 4 years of the application and the 2012 Test year was increased by $40,000 yearly to allocate the costs associated with rate application. Recovery will appear in quarters until the next cost of service application.

Maintenance of General Plant: 5675

$ 51,973

Account 5675 incurs the cost to general functions of labour, materials and expenses in which it is related to the maintenance of property and assets. The increase of $ 51, 973 is a result of updating of LUI's aging capital and maintenance most of which is specifically related to the maintenance required to LUI's buildings. Maintenance is required to preserve the buildings usefulness and for preventative actions against any failures in the office.

The largest variance to this account will occur in the year 2011 and 2012 as LUI undergoes a large renovation project to its office decaying interior and exterior. LUI has already started to perform the repair and replacement of the roofing, and reinforcement of the interior walls in the office building.

Special Purposes Charge Expense: 5681

$ (106,153)

LUI incurred a onetime special purpose charge expense of $ 106,153 due to the recovery of the expenses incurred and the expenditures made by the Ministry of Energy and Infrastructure in respect of its Green Energy Act and conservation demand programs or renewable energy program. Ontario Energy Board assessed LUI's "Q" variable as being calculated as $0.0003725. This regulation is to support conservation of energy and reduce demand on load during peak hours. This expense is not expected to recur at a later date, and expenses are current by being appropriately recovered via a rate rider.

OM&A Contra Account: 5695

$ 53,778

This account is used for the purpose of recording the offsetting entry for OM&A accounts recorded in account 1556, Smart Meter OM&A Variance account. LUI has no forecast for this account, and actuals for 2010 were amounting to ($53,778). The forecast of $0 for 2012 is misrepresentative of an increase of $53,778. LUI anticipates that the 1556 DVA Smart Meter OM&A will be approved for disposition in this 2012 Cost of Service Rate Application.

The table below sets out the OM&A cost per customer and Full Time equivalent employee.

Table 4-29 – OM&A Per Customer and FTE

Description	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 Test Year
Number of Customer (Excluding Connections)	9,118	9,386	9,503	9,666	9,832
Total OM&A Expense	$ 1,884,617	$ 1,855,224	$ 2,099,690	$ 2,449,126	$ 3,067,314
OM&A Cost per Customer	$ 207	$ 198	$ 221	$ 253	$ 312
Number of FTEs	16.50	17.50	19.00	19.50	22.25
FTE/ Customer	0.00181	0.00186	0.00200	0.00202	0.00226
OM&A Cost per FTE	$ 114,219.23	$ 106,012.78	$ 110,510.01	$ 125,596.20	$ 137,856.79

The number of customers includes the average number of residential, GS<50 and GS>50 customers as found in LUI's Load Forecast Weather Regression Model.

LUI has not included any one-time costs in this application of test year 2012. Any costs that are incurred over a period of time have been averaged over the four year period of this cost of service rate application.

LUI has included the cost of the Winter Warmth Assistance Program (LEAP) in account 5410 – Community Relations calculated as an average assistance amount of $5000 yearly.

Regulatory costs as indicated in the variance analysis are presented in Table 4-30. Regulatory costs for the 2012 rate application, including LUI consulting costs as well as anticipated Board and Intervener expenses have been considered over a four year period in the 2012 OM&A budget. The costs that have been included are indicated below:

Table 4-30 - Regulatory Costs

Regulatory Cost Category (A)	USoA Account (B)	Ongoing or One Time Cost (C)	2008 Actual (D)	2009 Actual (E)	2010 Actual (F)	2011 Bridge Year (G)	% Change in Bridge Year vs. Last Year of Actuals (H)=((G-F)/F)	2012 Test Year Forecast (I)	% Change in Bridge vs Test Years (J)=((I-G)/G)
1. OEB Annual Assessment	5655	Ongoing	$ 23,032	$ 18,914	$ 27,071	$ 33,624	24%	$ 34,632.66	3%
2. OEB Hearing Assessments	5655	Ongoing	$ -		$ -	$ -	0%	$ -	0%
3. OEB Section 30 Costs - (applicant initiated)	5655	Ongoing	$ 1,526	$ 745	$ 907	$ 1,371	51%	$ 1,411.80	3%
4. Expert Witness Cost for Regulatory Matters	5655	One-Time/4	$ -		$ -	$ -	0%	$ -	0%
5. Legal Costs for Regulatory Matters	5655	One-Time/4	$ 41,079	$ 7,378	$ 6,405	$ 7,820	22%	$ 18,054.60	131%
6. Consultant Costs for Regulatory Matters	5655/5666	One-Time/4	$ 14,430		$ 14,925	$ 31,003	108%	$ 35,382.38	14%
7. Operating Expenses Associated with Staff Resources Allocated to Regulatory Matters	5655	Ongoing	$ 1,077	$ 258	$ 982	$ 3,643	271%	$ 3,752.33	3%
8. Operating Expenses Associated with Other Resources Allocated to Regulatory Matters	5655	One-Time/4	$ -		$ -	$ -	0%	$ -	0%
9. Other Regulatory Agency Fees or Assessments	5655	Ongoing	$ -		$ -	$ -	0%	$ -	0%
10. Any other costs for Regulatory Matters	5655	Ongoing	$ 4,612	$ 5,154	$ 5,418	$ 5,586	3%	$ 5,753.58	3%
11. Intervenor Costs	5655	One-Time/4	$ -		$ 2,502	$ 2,500	0%	$ 4,575.00	83%
Sub Total - Ongoing Costs	5655		$ 30,246	$ 25,072	$ 34,378	$ 44,224	29%	$ 56,440	28%
Sub Total - One Time Costs	5655		$ 55,509	$ 7,378	$ 23,832	$ 41,323	73%	$ 47,123	14%
Total			**$ 85,754.95**	**$ 32,449.23**	**$ 58,209.77**	**$ 85,546.94**	**102%**	**$ 103,562.35**	**42%**

CHARGES TO AFFILIATES FOR SERVICES PROVIDED

Introduction

LUI provides and receives services from an affiliate company; Lakefront Utility Services Inc. (herein forth referred to as LUSI) and Cobourg Network Inc (herein forth referred to as CNI). LUI also performs services for its shareholder's the Town of Cobourg Holdings Inc. LUSI provides water service to the Town of Cobourg Holdings Inc. A summary of charges to affiliates for services provided in 2008 Actual, 2009 Actual, 2010 Actual together with the projections for the 2011 Bridge Year and 2012 Test Year, are shown in the following Table 8.

SERVICES PROVIDED BY AFFILIATES to LUI

Management Related Services

LUSI accounting staff provides accounting services to LUI including accounts receivable and payable, payroll, as well as financial planning and reporting. LUSI IT staff provides computer and network related services. In addition the President, Director of Finance and Regulatory Compliance, Treasurer and Corporate Secretary provide certain management services to LUI including strategic and financial planning, Board meeting preparation and attendance, and Human Resources. LUI is billed monthly for these services based on actual costs. Actual costs are passed through costs with no markup and are determined by the fully burdened hourly cost of each employee multiplied by the number of hours reported on their respective timesheets for services to LUI. All employees are required to submit timesheets weekly and are able to record time spent on activities in quarter hour increments.

Water & Sewer Billing Services

LUSI provides to LUI water and sewer billing services, who provides this service to Town of Cobourg and Cramahe Township. These services include meter reading, billing, bill collection and payment, and other customer services as required. By providing this service, LUI has been able to combine meter reading, billing, collections and customer service functions. Approximately 75% of the bills issued each month are shared electricity/water and sewer bills. A cost sharing arrangement was reached between LUSI and LUI under the assumption that the number of bills shared (75%) was a fair representation of all Billing and Collecting services provided by LUI and that the costs related to these shared amounts should be equally shared. LUSI has therefore billed LUI 37.5% (50% of 75%) of all Billing and Collecting expenses. This has been done through a cost re-allocation, with the appropriate amount of expense being reduced from LUSI's expenses and re-allocated to LUI's expenses.

Street Light and Sentinel Light Services

LUSI is a non-profit services company that provides manpower required by the Town of Cobourg to maintain the streetlights. LUI the affiliate provides LUSI the trucks required to perform the required functions in order for LUSI to meet its obligations. LUSI is charged the actual cost of the truck by LUI on a straight line pass thru methodology. These services are provided based on employee time at fully burdened rates, as well as truck and material expenses at fully burdened costs.

Fibre Rental

CNI provides internet, access and services to LUI and LUSI to operate the billing system through the application service provider model via Ecaliber in order to provide billing services for both LUI and LUSI. LUI rents fibre from CNI to connect its control room with its office, and garage and splits these costs with LUSI. Expenses are calculated at Cost and expenses for fibre rental are reported in account 5620 – Office Supply Expense.

SERVICES PROVIDED BY LUI to AFFILIATES

Office Rental

LUI rents office space to LUSI and other affiliate CNI. The office space is a shared building space and LUSI's office space is approximately 400 sq feet. CNI's office space is approximately 30 sq feet. Rent excludes property taxes, and excludes utilities. Rent is based on $10 per square foot. Rental revenue is recorded in account 4205 Interdepartmental Rental Revenue.

TABLE 4-31 - SHARED SERVICES/CORPORATE COST ALLOCATION

Name of Company		Service Offered	Pricing Methodology	G/L	Actual 2008	Actual 2009	Actual 2010	Bridge 2011	Test 2012
From	To								
LUI	LUSI	Office Rental	COST BASED	4205	$ 48,000	$ 48,000	$ 48,000	$ 48,000	$ 48,000
LUI	CNI	Office Rental	COST BASED	4205	$ 3,600	$ 3,600	$ 3,600	$ 3,600	$ 3,600
CNI	LUI	Fibre Rental	COST BASED	5620	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000
LUSI	LUI	Water & Sewer Billing Services	MARKET	4236	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000
LUSI	LUI	Finance Audit & Consulting	COST BASED	5630	$ 7,309	$ 62,427	$ 70,228	$ 125,423	$ 66,347
LUSI	LUI	Corporate Administration	COST BASED	5610.02.01.10	$ 315,825	$ 343,623	$ 411,753	$ 410,388	$ 370,397
LUSI	LUI	Directors Fees, Insurance, Meeting & Admin Expense	COST BASED	5605/5640.02.01.02	$ 47,932	$ 40,092	$ 33,576	$ 40,533	$ 40,533
LUSI	LUI	Management Fee	COST BASED	5605	$ -	$ -	$ 19,717	$ 20,000	$ 20,000

Purchase of Products and Services from Non-Affiliates

LUI purchases many services and products from third parties. Tables 4-32, 4-33 and 4-34 disclose the expenditures by vendor where the annual amount exceeded $5,000 per year, for the years 2008, 2009 and 2010, respectively. Table 4-35 contains the vendor information for 2011 where the year to date amount has exceeded $3000 as of May 31st 2011.

Commitments to suppliers have not been made for the Test Year (2012). Purchases for 2012 operating and capital works will continue to be based on the methodology contained within LUI's draft Procurement Policy, which has been attached at the end of this exhibit as Appendix B.

Table 4-32 2008 Non-Affiliate Services

Table 4-32 2008 Non-Affiliate Services

YEAR	VENDOR	Amount	Service/Product	GL	Procurement Method
2008	K-TEK ELECTRO SERVICES	$ 25,280.10	Transformer Maintenance	5017	RFQ
2008	MATACAST CO. LTD MATACA	$ 3,070.00	Transformer Maintenance	5017	RFQ
2008	AGO INDUSTRIES INC.	$ 3,604.33	Overhead Distribution Materials	5025	RFQ
2008	COMMERCIAL EQUIPMENT CORP	$ 3,922.38	Line Materials	5025	RFQ
2008	LAKEPORT POWER LTD	$ 4,036.08	Overhead Maintenance	5025	RFQ
2008	SHEPHERD UTILITY EQUIP.	$ 4,424.72	Line Materials	5025	RFQ
2008	HYDRO ONE NETWORKS INC.	$ 3,032.66	Repair work by others to jointly owned poles	5120	SOLE SERVICE
2008	GARY STEACY DISMANTLING	$ 4,380.00	Transformer Removal	5160	SOLE SERVICE
2008	HD UTILITIES SUPPLY HD U	$ 26,582.96	Materials	5160	RFQ
2008	OSHAWA PUC NETWORKS	$ 9,945.00	Meter Maintenance	5175	RFQ
2008	UTIL-ASSIST UTILAS	$ 16,157.63	Professional Services	5175	GROUP - CHEC
2008	THE RITZ	$ 37,540.49	Meter Reading	5310	SOLE SERVICE
2008	MEARIE MANAGEMENT INC. M	$ 44,898.84	Insurance	5610	GROUP INDUSTRY
2008	DIGITAL POSTAGE ON CALL	$ 27,600.63	Postage Provider - Administrative	5620	SOLE SERVICE
2008	MTS ALLSTREAM INC. ALLST	$ 3,110.79	Phone Provider - Administrative	5620	RFQ
2008	RICOH CANADA INC, RICOH	$ 4,105.54	Materials Supplier - Administrative	5620	SOLE SERVICE
2008	CRAWFORD & ASSOCIATES	$ 5,525.00	Staffing Consulting Services	5630	SOLE SERVICE
2008	ERE INFORMATION SECURITY	$ 4,580.00	Computer system audit inspection service	5630	SOLE SERVICE
2008	RDI CONSULTING INC. RD11	$ 8,000.00	Regulatory Consulting Services	5630	RFQ
2008	ALTERNATIVE RISK SERVICES	$ 7,534.08	Liability Insurance	5640	RFQ
2008	BDO DUNWOODY	$ 46,725.00	Regulatory Professional Services	5655	RFP
2008	ELECTRICAL SAFETY AUTHORITY	$ 4,611.76	Regulatory Professional Services	5655	REGULATOR
2008	ERIE THAMES SERVICES CORP	$ 110,298.45	Regulatory Professional Services	5655	MULTI YEAR CONTRACT
2008	OGILVY RENAULT OGILVY	$ 41,970.53	Regulatory Professional Services	5655	RFP
2008	ONTARIO ENERGY BOARD OEB	$ 24,557.94	Regulatory Professional Services	5655	REGULATOR
2008	ONTARIO LINE CLEARING &	$ 28,200.24	Tree Trimming	5135	RFP
2008	UTILITY FINANCIAL UTIFIN	$ 8,655.06	Regulatory Professional Services	5655	SOLE SERVICE
2008	ELECTRICITY DIST. ASSOC.	$ 13,150.00	Advertising Expenses	5660	GROUP/INDUSTRY
2008	UNION GAS LTD. UNION	$ 4,578.90	Gas Utility Provider	5675	SOLE SERVICE
2008	CHEC ASSOCIATION INC.	$ 9,601.00	Professional Services Group Consulting	5680	GROUP/CHEC
2008	UTILITIES STANDARDS FORUM	$ 7,200.00	Line Training	5680	GROUP/INDUSTRY

Table 4-33 2009 Non-Affiliate Services

YEAR	VENDOR	Amount	Service/Product	GL	Procurement Method
2009	AGO INDUSTRIES INC. #AGO	$ 5,588.82	Overhead Distribution Materials	5025	RFQ
2009	ALTERNATIVE RISK SERVICES	$ 14,316.40	Liability Insurance	5640	RFQ
2009	BEHAN CONSTRUCTION LTD. #	$ 3,784.44	Underground Line Maintenance/ Excavation	5045	RFQ
2009	CHEC ASSOCIATION INC. #CO	$ 25,486.98	Professional Services Group Consulting	5680	GROUP CHEC
2009	COLLINS BARROW #COLLIN	$ 15,150.00	Audit Review Professional Service	5630	RFQ
2009	COMMERCIAL EQUIPMENT CORP	$ 3,674.95	Line Materials	5025	RFQ
2009	CRAWFORD & ASSOCIATES #CR	$ 11,410.00	Staffing Consulting Services	5630	SOLE SERVICE
2009	DIGITAL POSTAGE ON CALL #	$ 28,613.89	Postage Provider - Administrative	5620	MARKET RATE
2009	DURHAM MANAGEMENT #DMC	$ 3,200.00	Professional Service Fees	5630	RFQ
2009	ECALIBER #ECALIB	$ 126,039.29	Software Upgrades	5340	RFQ
2009	ELECTRICAL SAFETY AUTHORI	$ 4,613.79	Regulatory Professional Services	5655	REGULATOR
2009	ELECTRICITY DIST. ASSOC.	$ 13,925.00	Advertising Expenses	5660	GROUP INDUSTRY
2009	EULER HERMES ACI #EULER	$ 13,928.10	Insurance	5640	GROUP INDUSTRY
2009	FERGUSON ELECTRIC #FERELE	$ 3,390.42	Office Renovation Service	5675	RFQ
2009	GRAFTON STONEMASONS & #GR	$ 12,627.50	Office Renovation Service	5675	RFQ
2009	HD UTILITIES SUPPLY #HD U	$ 26,887.95	Materials	5160	RFQ
2009	KLEEN ZONE LTD #KLEEN	$ 4,380.00	Office Maintenance Service	5675	RFQ
2009	K-TEK ELECTRO SERVICES #K	$ 5,000.00	Transformer Maintenance	5017	RFQ
2009	LAKEPORT POWER LTD #LAKEP	$ 24,628.81	Overhead Maintenance	5025	RFQ
2009	MEARIE MANAGEMENT INC. #M	$ 66,134.17	Insurance	5610	GROUP INDUSTRY
2009	OGILVY RENAULT #OGILVY	$ 7,377.63	Regulatory Professional Services	5655	SOLE SERVICE
2009	ONTARIO ENERGY BOARD #OEB	$ 19,981.24	Regulatory Professional Services	5655	REGULATOR
2009	ONTARIO LINE CLEARING & #	$ 32,810.00	Tree Trimming	5655	RFQ
2009	OSHAWA PUC NETWORKS #OSHA	$ 9,370.00	Meter Maintenance	5175	RFQ
2009	RICOH CANADA INC, #RICOH	$ 4,695.41	Materials Supplier - Administrative	5620	RFQ
2009	SHEPHERD UTILITY EQUIP. #	$ 16,629.84	Line Materials	5025	RFQ
2009	TELIZON INC/QUINTE LONG #	$ 6,235.42	Phone Provider	5620	MARKET RATE
2009	THE RITZ	$ 35,990.15	Meter Reading	5310	SOLE SERVICE
2009	UNION GAS LTD. #UNION	$ 5,136.30	Gas Utility Provider	5675	MARKET RATE
2009	UTIL-ASSIST #UTILAS	$ 12,274.80	Professional Services	5175	GROUP CHEC
2009	UTILITIES STANDARDS FORUM	$ 6,200.00	Line Training	5680	GROUP INDUSTRY
2009	WASTE MANAGEMENT #WASTE	$ 4,059.33	Recycling Service	5675	MARKET RATE

Table 4-34 2010 Non-Affiliate Services

YEAR	VENDOR	Amount	Product / Service	GL	Procurement Method
2010	1429714 ONTARIO IN 5126	$ 5,878.34	A/C System	5675	SOLE SERVICE
2010	AGO INDUSTRIES INC. #AGO	$ 3,857.65	Overhead Distribution Materials	5025	RFQ
2010	ALTERNATIVE RISK SERVICES	$ 6,782.40	Liability Insurance	5640	RFQ
2010	BEHAN CONSTRUCTION LTD. #	$ 4,434.42	Underground Line Maintenance/ Excavation	5045	RFQ
2010	BORDEN LADNER GERVAIS LLP	$ 6,405.28	Professional Services for Injuries and Damages	5644	RFP
2010	BURMAN ENERGY CONSULTANTS	$ 12,000.00	LRAM Services	5666	SOLE SERVICE
2010	CHEC ASSOCIATION INC. #CO	$ 29,567.91	Professional Services Group Consulting	5680	GROUP CHEC
2010	COLLINS BARROW #COLLIN	$ 19,750.00	Audit Review Professional Service	5630	RFQ
2010	COMMERCIAL EQUIPMENT CORP	$ 3,561.07	Line Materials	5025	RFQ
2010	CRAIG ENERGY SOLUTIONS #C	$ 28,000.00	Professional Consulting Services	5610	SOLE SERVICE
2010	CRAWFORD & ASSOCIATES #CR	$ 5,500.00	Staffing Consulting Services	5630	SOLE SERVICE
2010	CRESSMAN TREE MAINTENANCE	$ 61,225.00	Tree Trimming	5655	RFP
2010	CRU SOLUTIONS #CRUSOL	$ 10,515.57	Installation Services	5175	RFQ
2010	DIGITAL POSTAGE ON CALL #	$ 29,760.78	Postage Provider - Administrative	5620	MARKET RATE
2010	DURHAM MANAGEMENT #DMC	$ 7,747.50	Professional Service Fees	5630	RFQ
2010	ECALIBER #ECALIB	$ 155,722.20	Software Upgrades	5340	RFQ
2010	ELECTRICAL SAFETY AUTHORI	$ 5,972.50	Regulatory Professional Services	5655	REGULATOR
2010	EULER HERMES ACI #EULER	$ 9,461.00	Insurance	5640	RFQ
2010	GUILLEVIN INTERNATIONAL #	$ 3,316.42	Maintenance Product	5675	RFQ
2010	HD UTILITIES SUPPLY #HD U	$ 29,558.63	Materials	5160	RFQ
2010	KLEEN ZONE LTD #KLEEN	$ 5,157.31	Office Maintenance Service	5675	RFQ
2010	LAKEPORT POWER LTD #LAKEP	$ 8,618.24	Overhead Maintenance	5025	RFQ
2010	MEARIE MANAGEMENT INC. #M	$ 52,261.26	Insurance	5610	GROUP INDUSTRY
2010	MMI UTILITY SERVICES INC.	$ 3,610.00	Electric Distribution Service	5610	SOLE SERVICE
2010	ONTARIO ENERGY BOARD #OEB	$ 27,978.39	Regulatory Professional Services	5655	REGULATOR
2010	RICOH CANADA INC, #RICOH	$ 3,680.83	Materials Supplier - Administrative	5620	RFQ
2010	SANEXEN ENVIRONMENTAL SER	$ 7,740.00	Environmental Services	5160	SOLE SERVICE
2010	SHEPHERD UTILITY EQUIP. #	$ 27,641.98	Line Materials	5025	RFQ
2010	SPRINGBOARD MANAGEMENT #S	$ 15,000.00	Software Services/Product	5630	RFQ
2010	TELIZON INC/QUINTE LONG #	$ 6,103.43	Phone Provider	5620	MARKET RATE
2010	THE RITZ/NICK RIZZO #THE	$ 37,970.97	Meter Reading	5310	SOLE SERVICE
2010	UTILITIES STANDARDS FORUM	$ 10,300.00	Line Training	5680	GROUP INDUSTRY
2010	WASTE MANAGEMENT #WASTE	$ 3,421.36	Recycling Service	5675	SOLE SERVICE

Table 4-35 2011 Non-Affiliate Services

YEAR	VENDOR	Amount	GL	Product / Service	Procurement Method
2011	AGO INDUSTRIES INC 5382	$ 4,513.95	5025	Overhead Distribution Materials	RFQ
2011	ALTERNATIVE RISK SERVICES	$ 6,908.00	5640	Liability Insurance	RFQ
2011	CHEC ASSOCIATION INC. #CO	$ 56,749.95	5680	Professional Services Group Consulting	GROUP CHEC
2011	COLLINS BARROW #COLLIN	$ 15,600.00	5630	Audit Review Professional Service	RFQ
2011	CRAIG ENERGY SOLUTIONS #C	$ 38,132.50	5610	Professional Consulting Services	SOLE SERVICE
2011	CRU SOLUTIONS #CRUSOL	$ 3,050.00	5175	Installation Services	RFQ
2011	DIGITAL POSTAGE ON CALL #	$ 20,215.70	5620	Postage Provider - Administrative	MARKET RATE
2011	DURHAM MANAGEMENT #DMC	$ 6,905.00	5630	Professional Service Fees	RFQ
2011	ECALIBER #ECALIB	$ 71,579.00	5340	Software Upgrades	RFQ
2011	ELECTRICAL SAFETY AUTHORI	$ 5,054.94	5655	Regulatory Professional Services	REGULATOR
2011	EULER HERMES ACI #EULER	$ 18,672.00	5640	Insurance	RFQ
2011	HD UTILITIES SUPPL 5271	$ 10,340.80	5160	Materials	RFQ
2011	K-TEK ELECTRO SERV 5323	$ 19,486.12	5017	Transformer Maintenance	RFQ
2011	MEARIE MANAGEMENT INC. #M	$ 13,471.75	5610	Insurance	GROUP INDUSTRY
2011	ONTARIO ENERGY BOARD #OEB	$ 14,495.33	5655	Regulatory Professional Services	REGULATOR
2011	SHEPHERD UTILITY EQUIP. #	$ 3,864.76	5025	Line Materials	RFQ
2011	SPRINGBOARD MANAGEMENT #S	$ 15,060.00	5630	Software Services/Product	RFQ
2011	THE RITZ/NICK RIZZO #THE	$ 38,268.48	5310	Meter Reading	SOLE SERVICE
2011	UNION GAS LTD. #UNION	$ 3,049.52	5675	Gas Utility Provider	MARKET RATE
2011	UTILITY FINANCIAL #UTIFIN	$ 6,855.11	5655	Regulatory Professional Services	SOLE SERVICE

EMPLOYEE COMPENSATION, INCENTIVE PLAN EXPENSES, PENSION EXPENSE AND POST RETIREMENT BENEFITS:

Compensation/Performance System

Union

LUI's unionized staff is represented by the CUPE Canadian Union of Public Employees. The current collective agreement expires January 31, 2014 and LUI will be entering formal negotiations prior to then. The current agreement, was entered into in February 2010, and included annual wage increases of 3% per year for 2010, 2011, 2012, and 2013.

Executive/Management

LUI collects pay market data from Ontario's LDC and National/ Regional Salary Surveys in order to pay competitive salaries to its staff, and assist in retaining talented people. 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. Each employee's position within their respective range is reviewed based on performance and an inflationary adjustment. The planned for increase is 3% per year for 2010, 2011, 2012, and 2013. Each grade allows for five possible progression steps. Management employees and supervisors, except trade's forepersons, are not paid overtime pay. Changes to senior management compensation, if any, are approved by the Board of Directors. LUI does not offer any incentive or bonus compensation at this time.

Job performance is aligned with LUI's vision, mission and goals. Annually when qualifying employees are schedules for progression, a formal evaluation is conducted by the supervisor manager and is shared with the employee. If job performance is below LUI's accepted standard, pay progression is withheld. Job performance is reviewed for any internal promotions or job vacancies as well.

Benefits

A comprehensive and competitive benefits package exists which includes medical insurance, life insurance, vacation and an employee company shared 50/50 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 unless due to years of service and age, they no longer qualify.

All full time staff participates in Post-Retirement Benefits until the age of 65 years old, the accrued expense is based on an actuarial valuation. The latest copy of the valuation has been provided as Appendix D.

Employee Compensation and Benefits

LUI has set out the information in Table 4-36 below according consistent with Section 2.7.4 of the June 12, 2011 Ontario Energy Board Chapter Two of the Filing Requirements which states, "Where there are three or fewer employees in any category, the applicant should aggregate this category with the category to which it is most closely related. This higher level of aggregation should be continued, if required, to ensure that no category contains three or fewer employees." LUI has aggregated account 5605 with account 5615 and will show expenses and salaries in 5605 recorded into 5615. LUI has aggregated the executive and management together in the management category.

For the purposes of RRR reporting, LUI has previously reported the actual wages and salaries paid of all employees and did not include year-end accruals to the general ledger. LUI notes that in order to be consistent with the RRR 2.1.5 criteria effective May 1, 2010, all years have been reported on the same basis, thus temporary and contract staff, Board of Directors and students

have not been included. Previously reported 2.1.5 labour figures for 2008 to 2010 included these amounts.

The salaries and wages amount include all salaries and wages paid, inclusive of vacations, stat holidays, floater holidays, sick leave, bereavement leave and other miscellaneous paid leave (i.e. jury duty), which may be considered as benefits, however they are not considered for the purpose of analysis.

The benefits amounts include the employer's cost to provided Extended Health Care, Dental, Long Term Disability and Life Insurance to its employees.

Employee complement, compensation and benefits are set out in Table 4-36 below.

Table 4-36 2008-2012 Employee Complement Compensation Benefits

Number of Employees (FTEs including Part Time)	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Executives & Management	2.50	3.00	3.25	3.25	3.25
Non Union	4.00	4.25	5.00	5.50	5.75
Union	10.00	10.25	10.75	10.75	13.25
Total	**16.50**	**17.50**	**19.00**	**19.50**	**22.25**
Number of Part Time Employees					
Executives & Management					
Non Union	1.00	1.25	1.00	1.00	1.00
Union					
Total	**1.00**	**1.25**	**1.00**	**1.00**	**1.00**
Total Salary and Wages					
Executives & Management	$273,848	$307,106	$333,158	$347,900	$367,607
Non Union	$235,972	$287,852	$379,969	$455,487	$502,590
Union	$562,915	$537,374	$572,879	$562,250	$764,783
Total	**$1,072,735**	**$1,132,332**	**$1,286,006**	**$1,365,637**	**$1,634,980**
Current Benefits					
Executives & Management	$79,516	$84,073	$82,655	$88,458	$101,994
Non Union	$0	$0	$0	$0	$0
Union	$48,797	$52,979	$53,465	$55,599	$65,795
Total	**$128,313**	**$137,052**	**$136,120**	**$144,057**	**$167,789**
Accrued Pension and Post Retirement Benefits					
Executives & Management					
Non Union					
Union					
Total	**$73,986**	**$70,677**	**$89,371**	**$94,582**	**$110,164**
Total Benefits (Current + Accrued)					
Executives & Management	$51,643	$56,339.33	$58,416.63	$60,794.11	$62,494.50
Non Union	$44,500	$52,807.13	$66,624.56	$79,594.50	$85,442.09
Union	$106,156	$98,582.54	$100,449.81	$98,250.89	$130,015.89
Total	**$202,299**	**$207,729**	**$225,491**	**$238,639**	**$277,952**
Total Compensation (Salary, Wages & Benefits)					
Executives & Management	$325,491	$363,445	$391,575	$408,694	$430,102
Non Union	$280,472	$340,659	$446,594	$535,081	$588,032
Union	$669,071	$635,957	$673,329	$660,501	$894,799
Total	**$1,275,034**	**$1,340,061**	**$1,511,497**	**$1,604,276**	**$1,912,933**
Compensation - Average Yearly Base Wages					
Executives & Management	$109,539	$102,369	$102,510	$107,046	$113,110
Non Union	$58,993	$67,730	$75,994	$82,816	$87,407
Union	$55,826	$51,984	$52,889	$51,900	$57,455
Total	**$224,359**	**$222,082**	**$231,392**	**$241,762**	**$257,971**
Compensation - Average Yearly Overtime					
Executives & Management	$0	$0	$0	$0	$0
Non Union	$0	$0	$0	$0	$0
Union	$4,652	$4,539	$4,327	$4,327	$3,511
Total	**$4,652**	**$4,539**	**$4,327**	**$4,327**	**$3,511**
Compensation- Average Yearly Incentive Pay					
Executives & Management	$0	$0	$0	$0	$0
Non Union	$0	$0	$0	$0	$0
Union	$0	$0	$0	$0	$0
Total	**$0**	**$0**	**$0**	**$0**	**$0**
Compensation Average Yearly Benefits					
Executives & Management	$7,598	$7,282	$7,207	$7,515	$7,594
Non Union	$0	$0	$0	$0	$0
Union	$4,663	$4,589	$4,661	$4,723	$4,899
Total	**$12,261**	**$11,870**	**$11,868**	**$12,238**	**$12,492**
TOTAL COMPENSATION	**$1,275,034**	**$1,340,061**	**$1,511,497**	**$1,604,276**	**$1,912,933**
TOTAL COMPENSATION CHARGES TO OM&A	**$675,768**	**$656,630**	**$1,058,048**	**$802,138**	**$765,173**
TOTAL COMPENSATION CAPITALIZED	**$599,266**	**$683,431**	**$453,449**	**$802,138**	**$1,147,760**

Change in Employee Compensation & Benefits

2009 Actual vs. 2008 Actual

Management:
Change in FTE: +0.5
Change in Wages: +$33,258

A new management position of Chartered Accountant was implemented in the finance department in August 2009 and increasing the FTE based on the remainder of the year.

In 2009 management received an inflationary increase of 3.0% or approximately $8,215.44. The remaining increase of $25,043 relates to 5 months' salary for the newly created position and increases for minor progression within compensation bands for some positions.

Non-Union:
Change in FTE: +0.25
Change in Wages: + $51,880

An increase of 0.25 FTE in the non-union full time category relates to the position of Electric Distribution Sub-Foreman on a short time basis working on projects at year end of 2008 and carried into 2009. Typically these employees were compensated with wages but no health or pension benefits other than statutory benefits (CPP and EI). This position was dismissed in May of 2009, and results in an increase of $27,605.

In 2009 non-union received an inflationary increase of 3.0% or approximately $6,800. The remaining increase of $17,475 relates increases for minor progression within compensation bands for some positions.

Union:
Change in FTE: +.25
Change in Wages: -$25,541

The increase of 0.25 FTEs in union positions is the result of two changes. LUI hired two FTE's into the positions of lineman/ journeymen in November 2009 to fill the exit of one lineman that left LUI. In February 2009 the Metering Foreperson's position had been vacated and not filled. The resulting increase after a reduction of one employee was offset by the two positions that were filled in December 2009 (Linemen/Journeymen) and now counting as an increase of +0.25 FTE in 2009. The change in wage shows a reduction because of the offset throughout the entire year between February and December while the position was vacant. General wages increased by 3% as per the collective agreement by $14,580 and due to this it can be noted that the change in wages would have resulted in a larger negative value if not for the outcome of progression within job classifications and pay grades.

2010 Actual vs. 2009 Actual

Management:
Change in FTE: +0.25
Change in Wages: +$25,676

In 2010 the Accountant position that was created in 2009 in the Finance department was fully allocated throughout the year and shows an increase of +0.25 FTE. All other employees' allocations remained the same.

The change of +0.25 FTE represented an increase in salary relative to the previous year's hiring in the finance department of approximately $60,705 towards electric. This was offset by a management inflationary increase of 3%, increasing salaries by $9,214. The remaining change (approximately $16,461) relates to the staffing increase and any progression within compensation bands.

Non-Union:
Change in FTE: +0.75
Change in Wages: +$92,117

In 2010 LUI undertook the initiative of Smart Metering and required an employee full time for the management of this project. LUI hired internally one nonunion position was moved to another employment for Smart Metering in nonunion. This adjusted the office manager's time from previously 50% LUI to 100% and an addition of $59,036 to the wages in LUI nonunion. To backfill the office manager position, there was another internal hire from a union administration position; as a result 50% of time was added to nonunion and removed from union. Due to the growth within LUI a position was created in Human Resources and hired in May adding and addition of 50% FTE. The increase in wages being $10,475 for that portion of 2010 in relation to the new human resources personnel were with LUI. Therefore in total +1.5 FTE was added to non-union category in 2010.

The increase of +0.75 non-union FTEs from 2009 to 2010 is due to the difference of summer student employment within LUI. In 2009 LUI hired 7 part time students and in 2010 this was decreased by 3 positions to 4 summer students. The decrease of this staff outcomes in a -0.75FTE and resulted in a variance of approximately +0.75FTE for Nonunion within LUI.

In 2010 non-union received an inflationary increase of 3.0% or approximately $6,800. The remaining increase of $15,806 relates to increases for minor progression within compensation bands for some positions.

Union:
Change in FTE: +0.50
Change in Wages: +$35,505

Two union lineman positions were created in December 2009 resulting in a full allocation appearing in 2010 to increase +2.0FTE. As previously mentioned above there was an internal hire from a union position that occurred for undertaking smart metering initiatives. There was a hiring of another billing and collections clerk in May to backfill the movement of positions due to smart metering. The offset of this increase in union staff was the reallocation of time for the billing and collecting. There was a decrease of 85% allocation from 2009 due to decreasing from 67% of time billed to LUI down to 50%. The end result being an increase of +0.50 FTE in 2010.

Change in wages increasing by +$35,505 was due to the increase in lineman positions offset from the previous year, a 3% inflation increase of +$16,121 as per the collective agreement, and progression by some individuals within job classifications and pay grades, as per the collective agreement.

2011 Bridge vs. 2010 Actual

Management:
Change in FTE: NIL
Change in Wages: +$14,742

In February 2011 a new management position, VP of Operations, was implemented to fulfill the business needs of the Presidents retirement and the internal movement of the VP of Finance and Compliance being appointed the new president. It is anticipated that this movement within the management category going forward will null any changes and continue more efficiently.

Management received an inflationary increase of 3.0% or approximately $9,900. The balance of the increase in management salaries reflect the new VP of operations position and advancement for some positions, offset by any decreased wage replacement of the president.

Non-Union:
Change in FTE: +0.50
Change in Wages: +$75,518

In April 2011, a new nonunion position, Finance Analyst was created to complement the finance department as the previous finance management position was moved into the president position. The increase in +0.5 FTE is due to the hiring of this employee whose salary is 50% LUI. This increase will account for +$16,000 in nonunion. The reallocation of time for LUI's Safety

Coordinator was moved from union to nonunion in 2011 and accounts for +$29,700 of the wage increase in this section. LUI also notes that there was an increase in 2011 to the wages of summer students. The hiring of a summer student who assisted with projects such as CDM, documentation, and updated statistics increased wages by +$8,400.

In 2011 non-union received an inflationary increase of 3.0% or approximately $11,025. The remaining increase of $10,393 relates to increases for minor progression within compensation bands for some positions.

Union:
Change in FTE: NIL
Change in Wages: -$10,629

NIL changes in FTE's in union are due to the reallocation of LUI's safety coordinator to nonunion position and the hiring of addition administrative staff in March 2011 due to the growth of LUI.

The reduction in wages -$10,629 represents the wages associated with the above mentioned position moving into nonunion position, and is partially offset by the inflationary increase of 3% and minor progressions.

2012 Test vs. 2011 Bridge

Management:
Change in FTE: 0
Change in Wages: +$23,994
LUI expects minimal changes in the management group from 2011 to 2012. LUI has just undergone a change in presidency and has hired a Chartered Accountant and Vice President. LUI has also promoted an existing position into a Director Finance and Regulatory Complicance

which accounts for some of the increase. LUI does not foresee any significant changes to affect the Management Budget. The increase of +$23,994 in wages is due to the regular increase in progression, with compensation bands for various positions and the promotion.

Non-Union:
Change in FTE: +0.25
Change in Wages: +$53,178

LUI expects an increase of 0.25 FTE in the non-union group from 2011 to 2012. LUI anticipates the hiring of an engineer to replace a senior foreman nonunion management staff. LUI has developed strategic succession planning for the development of LUI's capital and LUI will be requiring a professionally accredited employee to carry out the responsibilities of daily operations. Increase of wages are credited to +$32,000 of an engineer, +$8,000 as overlap from previous years hiring a regulatory analyst, and $13,178 as LUI's nominal increase over 2011 progression and compensation for this group.

Union:
Change in FTE: +2.50
Change in Wages: + $202,536

The union FTEs will increase by 2.5 positions due to the hiring of new bodies, and transition of succession planning in the customer service & billing department and maintenance department for a full year in 2012. In the Maintenance and Billing and Collections departments LUI is faced with attrition matters and is planning forward for overlaps between retirement dates and proper training expenses. +0.25FTE and $35,869 is accounted for the replacement of one of LUI's retiring lineman and the overlap in succession planning. Increase of +0.25 FTE in the billing and collections department in the amount of $19, 640 is added to this account for the employee required to be hired for transition of retirees that are in this position currently.

LUI plans on hiring a Metering Technician Apprentice as +0.5 FTE an increasing the wages by +$34,875 for the responsibility of electric distribution metering assets to ensure proper functionality. This position will also be responsible for installing new complex metering systems and installing customer voltage monitoring equipment.

LUI also has in plan to hire a Technical Services Technician +0.5FTE and will increase the wages budget by +$34,875 for the responsibility of designs and service orders for new connections and service upgrades (ESA), producing designs for new overhead, underground capital work and capital distribution upgrades. The technical service technician will also be responsible for distribution asset management, SCADA system maintenance and FIT and micro-FIT connections.

An Increase of $71,740 is due to hiring of a line man apprentice +1.0FTE. The lineman apprentice will be hired as a 1st year apprentice of a 5 year Journeyman program. The apprentice will be trained on all aspects of Lakefront distribution and will be a first line defense against attrition issues Lakefront faces.

The remaining increase in wages +$5,537 is attributable to the 3% general wage increase and corresponding benefits based on the current collective agreement.

LUI has also anticipated an increase in OMERS pension costs due to correspondence released in June 28, 2011 regarding a 3-year strategy, 1% per year increase in OMERS premiums beginning in 2012.

LUI expects no change in the non-union group from 2011 to 2012. LUI anticipates the normal yearly hiring of summer students to help with vacation coverage. LUI has provided for a nominal increase over 2011 wages for this group.

The most recent actuarial report estimates 2012 post-employment benefit expense at $64,300.

OMERS Pension Expense and Post Retiree Benefits

OMERS Pension Expense

LUI's employees are members of the Ontario Municipal Employees Retirement System ("OMERS"). Accordingly, LUI has provided the OMERS pension premium information for 2008

Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year, and the 2012 Test Year in the table 4-37 below.

Table 4-37 Pension Premium Information

	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
OMERS Premium Paid	$ 75,483	$ 76,892	$ 87,984	$ 106,067	$ 127,483

Post-Retirement Benefits - Liability

LUI has provided post-retirement benefits accounting information as required and has included the change in Post-Retirement expense for 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year, and 2012 Test Year, in Table 14 below.

Post-Retirement Benefits - Premiums

LUI pays certain health, dental, and life insurance benefits on behalf of its retired employees up to the age of 65. This post retirement benefit program is a new incentive at LUI and only began in the year 2010 and is budgeted to continue going forward. LUI expects retirements to occur and therefore increases in this account in the next couple years, and has budgeted this into account with the inflation of these cost increases. Actual premiums paid for 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year, and 2012 Test Year, are shown in Table 4-38 below.

Table 4-38 Post-Retirement Benefit Information

	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Premiums & Expenses Paid	$ -	$ -	$ 5,080	$ 10,464	$ 16
Change in Accrued Liability	$ 7,941	$ 6,781	$ 4,787	$ 26,894	$ 8
Total Post Employment Benefit Expense	$ 7,941	$ 6,781	$ 9,867	$ 37,358	$ 24

Table 4-39 Summary of Post Retirement Accruals

Year	2007	2008	2009	2010	2011	2012
Premiums Accrued	$ 249,434	$ 257,375	$ 264,156	$ 268,943	$ 295,837	$ 304,712
$Increase / Year		$ 7,941	$ 6,781	$ 4,787	$ 26,894	$ 8,875
% Increase/ Year		3%	3%	2%	9%	3%
% Average Increase 2007-2012						4%

Table 4-40 Summary of Post-Retirement Benefits

Year	2007	2008	2009	2010	2011	2012
Premiums &Expenses Paid	0	0	0	$ 5,080	$ 10,464	$ 16,010
$Increase / Year	0	0	0	$ 5,080	$ 5,384	$ 5,546
% Increase/ Year	0%	0%	0%	100%	51%	35%

DEPRECIATION, AMORTIZATION AND DEPLETION

Amortization on capital assets is calculated as follows:

- Amortization is provided on a straight line basis for capital assets available for use over their estimated services lives.

- LUI's amortization policy has been to use the "half-year rule" when accounting for amortization expense for capital additions in the year the addition occurs. For this rate application, LUI has applied the "half year rule" for calculating depreciation expense for the year's 2008 to2012. .

- Depreciation rates are in line with rates set out in the APH. These rates are reflected in the tables that follow.

Table 4-41 Amortization Expense Summary

Amortization Expense Summary

Account	Description	2008 Amortization Expense	2009 Amortization Expense	2010 Amortization Expense	2011 Amortization Expense	2012 Amortization Expense
1610	Intangible Assets	-	-	-	-	-
1805	Land	-	-	-	-	-
1806	Land Rights	-	11,363.00	-	-	-
1808	Buildings and Fixtures	17,594	18,565.00	19,878	21,199	27,853
1810	Leasehold Improvements	-	-	-	-	-
1815	Transformer Station Equipment - Normally Primary	-	-	-	-	-
1820	Distribution Station Equipment - Normally Primary b	88,773	89,262.00	90,027	121,595	50,094
1825	Storage Battery Equipment	-	-	-	-	-
1830	Poles, Towers and Fixtures	24,541	46,160.00	38,253	53,293	48,421
1835	Overhead Conductors and Devices	273,618	277,929.00	271,145	271,121	88,231
1840	Underground Conduit	18,613	19,683.00	28,340	42,928	32,693
1845	Underground Conductors and Devices	111,469	112,597.00	117,601	121,478	75,595
1850	Line Transformers	163,194	182,448.00	192,821	203,914	158,330
1855	Services	16,061	16,959.00	18,767	20,495	8,820
1860	Dumb Meters	34,336	35,038.00	35,429	35,443	8,418
1860	Smart Meters	-	-	-	-	-
1905	Land	-	-	-	-	-
1906	Land Rights	-	-	-	-	-
1908	Buildings and Fixtures	-	-	-	-	-
1910	Leasehold Improvements	-	-	-	-	-
1915	Office Furniture and Equipment	16,521	15,190.00	14,153	6,953	-
1920	Computer Equipment - Hardware	28,172	21,040.00	7,407	11,240	9,453
1925	Computer Software	9,314	13,226.00	18,001	27,378	29,551
1930	Transportation Equipment > 3 tonnes	82,866	83,989.00	110,201	94,963	36,395
1935	Transportation Equipment < 3 tonnes	-	-	-	-	13,867
1940	Tools, Shop and Garage Equipment	8,182	12,061.00	-	18,931	100,463
1945	Measurement and Testing Equipment	-	-	936	1,871	-
1950	Power Operated Equipment	-	-	-	-	34,834
1955	Communication Equipment	-	-	-	-	1,871
1960	Miscellaneous Equipment	-	-	-	-	-
1970	Load Management Controls - Customer Premises	-	-	-	-	-
1975	Load Management Controls - Utility Premises	-	-	-	-	-
1980	System Supervisory Equipment	-	-	-	-	-
1985	Sentinel Lighting Rentals	-	-	-	-	-
1990	Other Tangible Property	-	-	-	-	-
1995	Contributions and Grants	- 54,621	(62,067.00)	- 68,886	- 69,693	-
2005	Property under Capital Lease	-	-	-	-	-
	NET AMORTIZATION EXPENSE	**838,633**	**893,443**	**894,073**	**983,109**	**724,889**

Details of LUI's depreciation by account number are provided in the Fixed Asset Continuity Schedule.

Table 4-42 Depreciation Expense – 2008

Account	Description	Opening Balance (a)	Less Fully Depreciated [1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e)=(c) + 0.5 x (d) (2)	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Adjustments (i)	Adjusted Depreciation Expense (j)= (h)+(i)
1610	Intangible Assets	582,400	-	582,400	76,800	620,800	0	0.00	-	-	-
1805	Land	219,284	-	219,284	0	219,284	0	0.00	-	-	-
1806	Land Rights	11,363	-	11,363	0	11,363	5	0.20	2,273	- 2,273	-
1808	Buildings and Fixtures	765,069	-	765,069	22,808	776,473	50	0.02	15,529	2,065	17,594
1810	Leasehold Improvements	-	-	-	0	-	0	0.00	-	-	-
1815	Transformer Station Equipment - Normally Primary	-	-	-	0	-	0	0.00	-	-	-
1820	Distribution Station Equipment - Normally Primary b	2,745,440	-	2,745,440	6,000	2,748,440	30	0.03	91,615	- 2,842	88,773
1825	Storage Battery Equipment	-	-	-	0	-	0	0.00	-	-	-
1830	Poles, Towers and Fixtures	3,987,894	-	3,987,894	173,875	4,074,832	25	0.04	162,993	- 138,452	24,541
1835	Overhead Conductors and Devices	3,158,069	(120,351.99)	3,278,421	294,660	3,425,751	25	0.04	137,030	136,588	273,618
1840	Underground Conduit	446,063	-	446,063	0	446,063	25	0.04	17,843	770	18,613
1845	Underground Conductors and Devices	2,815,942	-	2,815,942	0	2,815,942	25	0.04	112,638	- 1,169	111,469
1850	Line Transformers	3,817,949	-	3,817,949	573,895	4,104,896	25	0.04	164,196	- 1,002	163,194
1855	Services	408,197	-	408,197	10,955	413,675	25	0.04	16,547	- 486	16,061
1860	Dumb Meters	855,216	-	855,216	19,737	865,085	25	0.04	34,603	- 267	34,336
1860	Smart Meters	-	-	-	0	-	0	0.00	-	-	-
1905	Land	-	-	-	0	-	0	0.00	-	-	-
1906	Land Rights	-	-	-	0	-	0	0.00	-	-	-
1908	Buildings and Fixtures	428,577	(428,577.42)	857,155	0	857,155	15	0.07	57,144	- 57,144	-
1910	Leasehold Improvements	-	-	-	0	-	5	0.20	-	-	-
1915	Office Furniture and Equipment	83,191	(1,025.98)	84,217	1,750	85,092	10	0.10	8,509	8,012	16,521
1920	Computer Equipment - Hardware	161,543	(51,581.47)	213,124	3,924	215,087	5	0.20	43,017	- 14,845	28,172
1925	Computer Software	60,926	-	60,926	39,145	80,498	5	0.20	16,100	- 6,786	9,314
1930	Transportation Equipment > 3 tonnes	346,373	-	346,373	284,467	488,607	8	0.13	61,076	21,790	82,866
1935	Transportation Equipment < 3 tonnes	-	-	-	0	-	8	0.13	-	-	-
1940	Tools, Shop and Garage Equipment	82,487	(5,892.38)	88,379	8,387	92,572	10	0.10	9,257	- 1,075	8,182
1945	Measurement and Testing Equipment	-	-	-	0	-	10	0.10	-	-	-
1950	Power Operated Equipment	-	-	-	0	-	0	0.00	-	-	-
1955	Communication Equipment	-	-	-	0	-	0	0.00	-	-	-
1960	Miscellaneous Equipment	-	-	-	0	-	10	0.10	-	-	-
1970	Load Management Controls - Customer Premises	-	-	-	0	-	0	0.00	-	-	-
1975	Load Management Controls - Utility Premises	-	-	-	0	-	0	0.00	-	-	-
1980	System Supervisory Equipment	28,619	(28,619.05)	57,238	0	57,238	10	0.10	5,724	- 5,724	-
1985	Sentinel Lighting Rentals	-	-	-	0	-	0	0.00	-	-	-
1990	Other Tangible Property	-	-	-	0	-	0	0.00	-	-	-
1995	Contributions and Grants	- 1,229,648	-	- 1,229,648	(271,735)	- 1,365,516	25	0.04	- 54,621	- 0	- 54,621
2005	Property under Capital Lease	-	-	-	0	-	0	0.00	-	-	-
										-	-
										-	-
										-	-
	Total	**19,774,954**	**- 636,048**	**20,411,003**	**1,244,668**	**21,033,336**			**901,473**	**- 62,840**	**838,633**

Table 4-43 Depreciation Expense – 2009

Account	Description	Opening Balance (a)	Less Fully Depreciated [1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e)=(c) + 0.5 x (d) (2)	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Adjustments (i)	Adjusted Depreciation Expense (j)= (h)+(i)
1610	Intangible Assets	659,200	(106,336.00)	765,536	47,200	789,136	0	0.00	-	-	-
1805	Land	219,284	-	219,284	0	219,284	0	0.00	-	-	-
1806	Land Rights	11,363	(11,363.00)	22,726	0	22,726	5	0.20	4,545	6,818	11,363
1808	Buildings and Fixtures	787,877	-	787,877	74,242	824,998	50	0.02	16,500	2,065	18,565
1810	Leasehold Improvements	-	-	-	0	-	0	0.00	-	-	-
1815	Transformer Station Equipment - Normally Primary	-	-	-	0	-	0	0.00	-	-	-
1820	Distribution Station Equipment - Normally Primary b	2,751,440	-	2,751,440	23,373	2,763,127	30	0.03	92,104	- 2,842	89,262
1825	Storage Battery Equipment	-	-	-	0	-	0	0.00	-	-	-
1830	Poles, Towers and Fixtures	4,161,770	(3,461,302.00)	7,623,072	104,867	7,675,505	25	0.04	307,020	- 260,860	46,160
1835	Overhead Conductors and Devices	3,332,377	-	3,332,377	232,804	3,448,779	25	0.04	137,951	139,978	277,929
1840	Underground Conduit	446,063	-	446,063	53,478	472,802	25	0.04	18,912	771	19,683
1845	Underground Conductors and Devices	2,815,942	-	2,815,942	56,372	2,844,128	25	0.04	113,765	- 1,168	112,597
1850	Line Transformers	4,391,844	-	4,391,844	388,797	4,586,242	25	0.04	183,450	- 1,002	182,448
1855	Services	419,152	-	419,152	33,951	436,128	25	0.04	17,445	- 486	16,959
1860	Dumb Meters	874,954	-	874,954	15,362	882,635	25	0.04	35,305	- 267	35,038
1860	Smart Meters	-	-	-	0	-	0	0.00	-	-	-
1905	Land	-	-	-	0	-	0	0.00	-	-	-
1906	Land Rights	-	-	-	0	-	0	0.00	-	-	-
1908	Buildings and Fixtures	-	-	-	0	-	15	0.07	-	-	-
1910	Leasehold Improvements	-	-	-	0	-	5	0.20	-	-	-
1915	Office Furniture and Equipment	83,915	(17,417.00)	101,332	41,318	121,991	10	0.10	12,199	2,991	15,190
1920	Computer Equipment - Hardware	113,886	(6,593.00)	120,479	10,525	125,741	5	0.20	25,148	- 4,108	21,040
1925	Computer Software	100,071	(33,939.00)	134,010	0	134,010	5	0.20	26,802	- 13,576	13,226
1930	Transportation Equipment > 3 tonnes	630,840	(100,406.00)	731,246	54,788	758,640	8	0.13	94,830	- 10,841	83,989
1935	Transportation Equipment < 3 tonnes	-	-	-	0	-	8	0.13	-	-	-
1940	Tools, Shop and Garage Equipment	84,981	-	84,981	73,749	121,855	10	0.10	12,186	- 125	12,061
1945	Measurement and Testing Equipment	-	-	-	0	-	10	0.10	-	-	-
1950	Power Operated Equipment	-	-	-	0	-	0	0.00	-	-	-
1955	Communication Equipment	-	-	-	0	-	0	0.00	-	-	-
1960	Miscellaneous Equipment	-	-	-	0	-	10	0.10	-	-	-
1970	Load Management Controls - Customer Premises	-	-	-	0	-	0	0.00	-	-	-
1975	Load Management Controls - Utility Premises	-	-	-	0	-	0	0.00	-	-	-
1980	System Supervisory Equipment	-	-	-	0	-	10	0.10	-	-	-
1985	Sentinel Lighting Rentals	-	-	-	0	-	0	0.00	-	-	-
1990	Other Tangible Property	-	-	-	0	-	0	0.00	-	-	-
1995	Contributions and Grants	- 1,501,383	-	- 1,501,383	(100,595)	- 1,551,681	25	0.04	- 62,067	0	- 62,067
2005	Property under Capital Lease	-	-	-	0	-	0	0.00	-	-	-
										-	-
										-	-
										-	-
	Total	**20,383,574**	**- 3,737,356**	**24,120,930**	**1,110,231**	**24,676,045**			**1,036,096**	**- 142,653**	**893,443**

Table 4-44 Depreciation Expense – 2010

Account	Description	Opening Balance (a)	Less Fully Depreciated [1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e)=(c) + 0.5 x (d) (2)	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Adjustments (i)	Adju Deprec Expe (j)= (h
1610	Intangible Assets	600,064	(545,198.00)	1,145,262	0	1,145,262	0	0.00	-	-	
1805	Land	219,284	-	219,284	0	219,284	0	0.00	-	-	
1806	Land Rights	-	-	-	0	-	5	0.20	-	-	
1808	Buildings and Fixtures	862,119	-	862,119	57,097	890,667	50	0.02	17,813	2,065	
1810	Leasehold Improvements	-	-	-	0	-	0	0.00	-	-	
1815	Transformer Station Equipment - Normally Primary	-	-	-	0	-	0	0.00	-	-	
1820	Distribution Station Equipment - Normally Primary b	2,774,813	(35,092.53)	2,809,906	22,514	2,821,163	30	0.03	94,039	- 4,012	
1825	Storage Battery Equipment	-	-	-	0	-	0	0.00	-	-	
1830	Poles, Towers and Fixtures	805,335	-	805,335	301,976	956,323	25	0.04	38,253	0	
1835	Overhead Conductors and Devices	3,565,181	-	3,565,181	248,573	3,689,467	25	0.04	147,579	123,566	
1840	Underground Conduit	499,541	-	499,541	379,402	689,242	25	0.04	27,570	771	
1845	Underground Conductors and Devices	2,872,314	-	2,872,314	193,840	2,969,234	25	0.04	118,769	- 1,169	
1850	Line Transformers	4,780,641	-	4,780,641	330,408	4,945,845	25	0.04	197,834	- 5,012	
1855	Services	453,103	-	453,103	56,426	481,316	25	0.04	19,253	- 486	
1860	Dumb Meters	890,316	-	890,316	4,147	892,389	25	0.04	35,696	- 267	
1860	Smart Meters	-	-	-	0	-	0	0.00	-	-	
1905	Land	-	-	-	0	-	0	0.00	-	-	
1906	Land Rights	-	-	-	0	-	0	0.00	-	-	
1908	Buildings and Fixtures	-	-	-	0	-	15	0.07	-	-	
1910	Leasehold Improvements	-	-	-	0	-	5	0.20	-	-	
1915	Office Furniture and Equipment	107,816	(64,747.46)	172,564	13,957	179,542	10	0.10	17,954	- 3,801	
1920	Computer Equipment - Hardware	117,818	(94,925.99)	212,744	8,308	216,898	5	0.20	43,380	- 35,972	
1925	Computer Software	66,132	-	66,132	47,744	90,004	5	0.20	18,001	0	
1930	Transportation Equipment > 3 tonnes	585,222	(190,134.00)	775,356	364,617	957,664	8	0.13	119,708	- 9,507	
1935	Transportation Equipment < 3 tonnes	-	-	-	0	-	8	0.13	-	-	
1940	Tools, Shop and Garage Equipment	158,730	-	158,730	0	158,730	10	0.10	15,873	- 15,873	
1945	600,064	-	-	-	18,712	9,356	10	0.10	936	0	
1950	Power Operated Equipment	-	-	-	0	-	0	0.00	-	-	
1955	Communication Equipment	-	-	-	0	-	0	0.00	-	-	
1960	Miscellaneous Equipment	-	-	-	0	-	10	0.10	-	-	
1970	Load Management Controls - Customer Premises	-	-	-	0	-	0	0.00	-	-	
1975	Load Management Controls - Utility Premises	-	-	-	0	-	0	0.00	-	-	
1980	System Supervisory Equipment	-	-	-	0	-	10	0.10	-	-	
1985	Sentinel Lighting Rentals	-	-	-	0	-	0	0.00	-	-	
1990	Other Tangible Property	-	-	-	0	-	0	0.00	-	-	
1995	Contributions and Grants	- 1,601,978	-	- 1,601,978	(555,681)	- 1,879,819	25	0.04	- 75,193	6,307	-
2005	Property under Capital Lease	-	-	-	0	-	0	0.00	-	-	
										-	
										-	
										-	
	Total	**17,756,449**	**- 930,098**	**18,686,547**	**1,492,040**	**19,432,567**			**837,463**	**56,610**	

Notes:

Table 4-45 Depreciation Forecasted Expense – 2011

Account	Description	Opening Balance (a)	Less Fully Depreciated [1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e)=(c) + 0.5 x (d) (2)	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Adjustments (i)	Adjusted Depreciation Expense (j)= (h)+(i)
1610	Intangible Assets	54,866	(54,866.00)	109,732	0	109,732	0	0	-	-	-
1805	Land	219,284	-	219,284	0	219,284	0	0.00	-	-	-
1806	Land Rights	-	-	-	0	-	5	0.20	-	-	-
1808	Buildings and Fixtures	919,216	-	919,216	75,000	956,716	50	0.02	19,134	2,065	21,199
1810	Leasehold Improvements	-	-	-	0	-	0	0.00	-	-	-
1815	Transformer Station Equipment - Normally Primary	-	-	-	0	-	0	0.00	-	-	-
1820	Distribution Station Equipment - Normally Primary b	2,762,235	-	2,762,235	0	2,762,235	30	0.03	92,075	29,521	121,595
1825	Storage Battery Equipment	-	-	-	0	-	0	0.00	-	-	-
1830	Poles, Towers and Fixtures	1,107,311	-	1,107,311	450,000	1,332,311	25	0.04	53,292	0	53,293
1835	Overhead Conductors and Devices	3,813,754	-	3,813,754	230,000	3,928,754	25	0.04	157,150	113,971	271,121
1840	Underground Conduit	878,943	-	878,943	350,000	1,053,943	25	0.04	42,158	771	42,928
1845	Underground Conductors and Devices	3,066,154	-	3,066,154	0	3,066,154	25	0.04	122,646	- 1,169	121,478
1850	Line Transformers	5,111,049	-	5,111,049	240,000	5,231,049	25	0.04	209,242	- 5,328	203,914
1855	Services	509,529	-	509,529	30,000	524,529	25	0.04	20,981	- 486	20,495
1860	Dumb Meters	894,462	(688,736.23)	1,583,199	20,000	1,593,199	25	0.04	63,728	- 28,285	35,443
1860	Smart Meters	1,566,824	-	1,566,824	255,355	1,694,502	0	0.00	-	-	-
1905	Land	-	-	-	0	-	0	0.00	-	-	-
1906	Land Rights	-	-	-	0	-	0	0.00	-	-	-
1908	Buildings and Fixtures	-	-	-	0	-	15	0.07	-	-	-
1910	Leasehold Improvements	-	-	-	0	-	5	0.20	-	-	-
1915	Office Furniture and Equipment	-	-	-	0	-	10	0.10	5,862	1,090	6,953
1920	Computer Equipment - Hardware	57,026	-	57,026	25,000	69,526	5	0.20	7,467	3,773	11,240
1925	Computer Software	31,199	-	31,199	50,000	56,199	5	0.20	11,240	16,138	27,378
1930	Transportation Equipment > 3 tonnes	69,641	-	69,641	50,000	94,641	8	0.13	49,488	45,476	94,963
1935	Transportation Equipment < 3 tonnes	44,235	-	44,235	8,546	48,508	8	0.13	13,867	- 13,867	-
1940	Tools, Shop and Garage Equipment	759,705	-	759,705	0	759,705	10	0.10	75,970	- 57,040	18,931
1945	Measurement and Testing Equipment	-	-	-	0	-	10	0.10	-	1,871	1,871
1950	Power Operated Equipment	158,730	-	158,730	75,000	196,230	0	0.00	-	-	-
1955	Communication Equipment	18,712	-	18,712	0	18,712	0	0.00	-	-	-
1960	Miscellaneous Equipment	-	-	-	0	-	10	0.10	-	-	-
1970	Load Management Controls - Customer Premises	-	-	-	0	-	0	0.00	-	-	-
1975	Load Management Controls - Utility Premises	-	-	-	0	-	0	0.00	-	-	-
1980	System Supervisory Equipment	-	-	-	0	-	10	0.10	-	-	-
1985	Sentinel Lighting Rentals	-	-	-	0	-	0	0.00	-	-	-
1990	Other Tangible Property	-	-	-	0	-	0	0.00	-	-	-
1995	Contributions and Grants	-	-	-	0	-	25	0.00	- 30,895	- 38,798	- 69,693
2005	Property under Capital Lease	-	-	-	0	-	0	0.00	-	-	-
										-	
										-	-
										- 1,119,962	-
	Total	**22,042,874**	**- 743,602**	**22,786,476**	**1,858,901**	**23,715,926**			**913,406**	**69,703**	**983,109**

Notes:

Table 4-46 Depreciation Forecasted Expense – 2012

Account	Description	Opening Balance (a)	Less Fully Depreciated [1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e)=(c) + 0.5 x (d) (2)	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Adjustments (i)	Adjusted Depreciation Expense (j)= (h)+(i)
1610	Intangible Assets	-	-	-	0	-	0	0.00	-	-	-
1805	Land	219,284	-	219,284	0	219,284	0	0.00	-	-	-
1806	Land Rights	-	-	-	0	-	5	0.20	-	-	-
1808	Buildings and Fixtures	994,216	-	994,216	375,000	1,181,716	50	0.02	23,634	4,218	27,853
1810	Leasehold Improvements	-	-	-	0	-	0	0.00	-	-	-
1815	Transformer Station Equipment - Normally Primary	-	-	-	0	-	0	0.00	-	-	-
1820	Distribution Station Equipment - Normally Primary b	2,762,235	-	2,762,235	0	2,762,235	30	0.03	92,075	- 41,981	50,094
1825	Storage Battery Equipment	-	-	-	0	-	0	0.00	-	-	-
1830	Poles, Towers and Fixtures	1,557,311	-	1,557,311	240,000	1,677,311	25	0.04	67,092	- 18,672	48,421
1835	Overhead Conductors and Devices	4,043,754	-	4,043,754	209,000	4,148,254	25	0.04	165,930	- 77,700	88,231
1840	Underground Conduit	1,228,943	-	1,228,943	160,000	1,308,943	25	0.04	52,358	- 19,665	32,693
1845	Underground Conductors and Devices	3,066,154	-	3,066,154	0	3,066,154	25	0.04	122,646	- 47,051	75,595
1850	Line Transformers	5,351,049	-	5,351,049	192,000	5,447,049	25	0.04	217,882	- 59,552	158,330
1855	Services	539,529	-	539,529	24,000	551,529	25	0.04	22,061	- 13,241	8,820
1860	Dumb Meters	225,726	-	225,726	20,000	235,726	25	0.04	9,429	- 1,011	8,418
1860	Smart Meters	1,822,179	-	1,822,179	0	1,822,179	0	0.00	-	112,744	112,744
1905	Land	-	-	-	0	-	0	0.00	-	-	-
1906	Land Rights	-	-	-	0	-	0	0.00	-	-	-
1908	Buildings and Fixtures	-	-	-	0	-	15	0.07	-	-	-
1910	Leasehold Improvements	-	-	-	0	-	5	0.20	-	-	-
1915	Office Furniture and Equipment	-	-	-	0	-	10	0.10	5,862	- 5,862	-
1920	Computer Equipment - Hardware	82,026	-	82,026	25,000	94,526	5	0.20	7,467	1,986	9,453
1925	Computer Software	81,199	-	81,199	150,000	156,199	5	0.20	31,240	- 1,689	29,551
1930	Transportation Equipment > 3 tonnes	119,641	-	119,641	325,000	282,141	8	0.13	49,488	- 13,092	36,395
1935	Transportation Equipment < 3 tonnes	44,235	-	44,235	0	44,235	8	0.13	13,867	-	13,867
1940	Tools, Shop and Garage Equipment	759,705	-	759,705	55,000	787,205	10	0.10	78,720	21,743	100,463
1945	Measurement and Testing Equipment	-	-	-	0	-	10	0.10	-	-	-
1950	Power Operated Equipment	233,730	-	233,730	394,000	430,730	0	0.00	-	34,834	34,834
1955	Communication Equipment	18,712	-	18,712	0	18,712	0	0.00	-	1,871	1,871
1960	Miscellaneous Equipment	-	-	-	0	-	10	0.10	-	-	-
1970	Load Management Controls - Customer Premises	-	-	-	0	-	0	0.00	-	-	-
1975	Load Management Controls - Utility Premises	-	-	-	0	-	0	0.00	-	-	-
1980	System Supervisory Equipment	-	-	-	0	-	10	0.10	-	-	-
1985	Sentinel Lighting Rentals	-	-	-	0	-	0	0.00	-	-	-
1990	Other Tangible Property	-	-	-	0	-	0	0.00	-	-	-
1995	Contributions and Grants	-	-	-	0	-	25	0.00	- 30,895	30,895	-
2005	Property under Capital Lease	-	-	-	0	-	0	0.00	-	-	-
										- 79,693	- 79,693
										-	-
										773,769	773,769
	Total	**23,149,626**	**-**	**23,149,626**	**2,169,000**	**24,234,126**			**928,857**	**- 91,224**	**837,633**

Notes:

DETERMINATION OF LOSS ADJUSTMENT FACTORS

Total Loss Factor

LUI has calculated the total loss factor to be applied to customers' consumption based on the average wholesale and retail kWh for the years 2005 to 2010. The calculations are summarized in Table 4-47 below. LUI chose to use a 6 year average for a more accurate representation of trending over time.

Table 4-47 Total Loss Factor Calculations

	Lakefront Utilities Inc.								
	Losses in Distributor System		**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**6 Year Average**
A	"Wholesale" kWh (IESO) **Qty at the Meter**		292,286,452	293,670,333	295,056,126	281,805,823	258,040,717	261,165,589	280,337,506.47
B	"Wholesale" kWh (GEN)								-
C	Net "Wholesale" kWh (A)-(B)		292,286,452	293,670,333	295,056,126	281,805,823	258,040,717	261,165,589	280,337,506.47
									-
D	Retail kWh (Distributor) **Qty at the Meter**		277,862,274	283,065,421	281,755,268	271,486,078	245,046,862	248,913,436	268,021,556.72
E	Portion of Retail kWh delivered by distributor for Large Use Customers		-	-	-	-	-	-	-
F	Net "Retail" kWh (D)-(E)		277,862,274	283,065,421	281,755,268	271,486,078	245,046,862	248,913,436	268,021,556.72
G	Distribution Loss Factor [(C)/(F)]		1.0519	1.0375	1.0472	1.0380	1.0530	1.0492	1.0461
	Losses Upstream of Distributor's System								
H	Supply Facility Loss Factor		1.00740	1.00736	1.01003	1.01136	1.01169	1.01173	1.0099
	Three Year Average								1.0116
	Total Utility Loss Adjustment Factor								**LAF**
	Supply Facility Loss Factor								1.0099
I	**Total Loss Factor**								
	Secondary Metered Customer								
	Total Loss Factor - Secondary Metered Customer < 5,000kW								1.0565
	Total Loss Factor - Secondary Metered Customer > 5,000kW								n/a
	Primary Metered Customer								
	Total Loss Factor - Primary Metered Customer < 5,000kW								1.0460
	Total Loss Factor - Primary Metered Customer > 5,000kW								n/a

Supply Facility Loss Factor

The supply facility loss factor (the "SFLF") calculation is shown in Table 4-48 and represents the losses on supply to LUI. The SFLF is calculated on the measured quantities between the

transformer stations and the wholesale meter points. The SFLF is used in the calculations of the total loss factor above based on the 2005 to 2010 averages.

Table 4-48 Supply Facility Loss Factor

2005	2006	2007	2008	2009	2010	TOTALS
1.0074	1.007357	1.010027	1.011364	1.011686	1.011735	1.009928

Total Loss Factor by Class

Table 4-49 sets out the class-specific Loss Factors used by LUI in the calculation of commodity and other non-distribution charges.

Table 4-49 Total Loss Factor by Class

Total Utility Loss Adjustment Factor		LAF
Supply Facility Loss Factor		1.0099
Distibution Loss Factor		1.0461
Distribution Loss Factor - Secondary Metered Customer < 5000kW		1.0565
Distribution Loss Factor - Primary Metered Customer < 5000 kW		1.0357
Total Loss Factor		
Total Loss Factor - Secondary Metered Customer < 5000kW		1.0565
Total Loss Factor - Primary Metered Customer < 5000kW		1.0460

Materiality Analysis on Distribution Losses

LUI's Total Loss factor is 5.65%. Pursuant to the Filing Requirements, as the Distribution Loss Adjustment factor is less than 5%, LUI is not required to provide an explanation of, or justification for, its total loss factor. LUI's loss factor of 1.0565 is reported to be higher than the previous cost of service filing in 2008 as detailed below.

During the 2008 rate application, LUI applied the loss factor against the wholesale kWh, and consequently had reported inaccurate calculations of its loss factor. This inaccuracy affected the data in 2005 and 2006 to force LUI's loss factor to appear lower than it really was. As well the data used in 2008 used inconsistent unbilled data. The final issue with the data in 2008, is that it included overbilling of a major customer, which was corrected in the 2007-2008 year, then caused an increase in LUI's loss factor.

When properly recalculated, the total loss factor would be closer to 6.05%. Whereas LUI had filed a distribution loss factor of 1.0494 and a total loss factor of 5.41%. In conclusion LUI's actual Total Loss Factor that is being filed for 2012 cost of service has been reduced, as per LUI's strategy from 1.0605 to 1.0565.

Below are the calculations for the 2008 accurately allocated figures;

Table 4-50 Adjusted 2004 Loss Factor

Total Utility Loss Adjustment Factor						
		2004 Adjusted	2004 Actual	2005	2006	
"Wholesale" kWh (IESO) **Qty at the Meter**		295,392,679.00	295,392,679.00	292,286,452	293,670,333	
"Wholesale" kWh (GEN)						
Net "Wholesale" kWh (A)-(B)		295,392,679.00	295,392,679.00	292,286,452	293,670,333	
Retail kWh (Distributor) **Qty at the Meter**		276,130,945.00	276,378,966.00	277,862,274	283,065,421	
				-	-	
Net "Retail" kWh (D)-(E)		276,130,945.00	276,378,966.00	277,862,274	283,065,421	
						3 Year Average
Distribution Loss Factor [(C)/(F)]	DLF		1.0688	1.0519	1.0375	1.0527
		1.0045%	**1.0045%**			
Supply Facility Loss Factor	SFLF		1.0073	1.00740	1.00736	1.0074
						1.0605
Total Utility Loss Adjustment Factor						

TAX CALCULATIONS

LUI 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. Table 17 below provides a summary of 2008 Actual, 2009 Actual, and 2010 Actual income taxes included in audited statements, 2011 Bridge Year estimate using current rates, and 2012 Test Year income taxes based on revised rates. The amounts for Ontario Capital Tax are $2,946 for 2010 Actual and $ Nil for 2011. This amount has decreased due to Ontario Capital Tax rates and LUI has reflected the cessation of the capital tax rate effectively July 1 2010.

Summary of Income Taxes Table 4-51

Description	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Income Taxes	$ 557,613	$ 355,241	$ 254,247	$ 32,287	$ 35,198
Ontario Capital Tax	$ 1,695	$ 4,756	$ 2,946	-	-
Total Taxes	$ 559,308	$ 359,997	$ 257,193	$ 32,287	$ 35,198

LUI's detailed tax calculations using the most recent tax rates are provided below Tables 4-52.

Table 4-52 Corporate Tax Rates

Corporate Tax Rates

Corporate Tax Rates for Tax Year:	2011 Bridge	2012 Test
OCT Exemption	15,000,000	15,000,000
Federal Income Tax	16.50%	15.00%
Ontario Income Tax	11.75%	11.25%
Combined Income Tax	28.25%	15.50%
Ontario Capital Tax Rate	0.000%	0.000%
Large Corporation Tax Rate		
Large Corporation Tax Exemption		

No capital tax as of July 2010

Table 4-53 2011 Tax Calculations

Determination of Tax Adjustments to Accounting Income for 2011

Line Item	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Utility Amount
Additions:				
Interest and penalties on taxes	103	0	0	0
Amortization of tangible assets	104	1,127,296	0	1,127,296
Amortization of intangible assets	106	0	0	0
Recapture of capital cost allowance from Schedule 8	107	0	0	0
Gain on sale of eligible capital property from Schedule 10	108	0	0	0
Income or loss for tax purposes- joint ventures or partnerships	109		0	0
Loss in equity of subsidiaries and affiliates	110	0	0	0
Loss on disposal of assets	111	0	0	0
Charitable donations	112		0	0
Taxable Capital Gains	113	0	0	0
Political Donations	114	0	0	0
Deferred and prepaid expenses	116	0	0	0
Scientific research expenditures deducted on financial statements	118	0	0	0
Capitalized interest	119	0	0	0
Non-deductible club dues and fees	120		0	0
Non-deductible meals and entertainment expense	121		0	0
Non-deductible automobile expenses	122	0	0	0
Non-deductible life insurance premiums	123	0	0	0
Non-deductible company pension plans	124	0	0	0
Tax reserves beginning of year	125	0	0	0
Reserves from financial statements- balance at end of year	126	295,837	0	295,837
Soft costs on construction and renovation of buildings	127	0	0	0
Book loss on joint ventures or partnerships	205	0	0	0
Capital items expensed	206	0	0	0
Debt issue expense	208	0	0	0
Development expenses claimed in current year	212	0	0	0
Financing fees deducted in books	216	0	0	0
Gain on settlement of debt	220	0	0	0
Non-deductible advertising	226	0	0	0
Non-deductible interest	227	0	0	0
Non-deductible legal and accounting fees	228	0	0	0
Recapture of SR&ED expenditures	231	0	0	0
Share issue expense	235	0	0	0
Write down of capital property	236	0	0	0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	0	0	0
Interest Expensed on Capital Leases	290	0	0	0
Realized Income from Deferred Credit Accounts	291	0	0	0
Pensions	292	0	0	0
Non-deductible penalties	293	0	0	0
Debt Financing Expenses for Book Purposes	294		0	0
Other Additions (Apprenticeship Tax Credits)	295	0	0	0
Total Additions		**1,423,133**	**0**	**1,423,133**
Deductions:				
Gain on disposal of assets per financial statements	401		0	0
Dividends not taxable under section 83	402	0	0	0
Capital cost allowance from Schedule 8	403	1,221,889	0	1,221,889
Terminal loss from Schedule 8	404	0	0	0
Cumulative eligible capital deduction from Schedule 10	405	0	0	0
Allowable business investment loss	406	0	0	0
Deferred and prepaid expenses	409	0	0	0
Scientific research expenses claimed in year	411	0	0	0
Tax reserves end of year	413	0	0	0
Reserves from financial statements - balance at beginning of year	414	268,943	0	268,943
Contributions to deferred income plans	416	0	0	0
Book income of joint venture or partnership	305	0	0	0
Equity in income from subsidiary or affiliates	306	0	0	0
Interest capitalized for accounting deducted for tax	390	0	0	0
Capital Lease Payments	391	0	0	0
Non-taxable imputed interest income on deferral and variance accounts	392	0	0	0
Financing Fees for Tax Under S.20(1)(e)	393	0	0	0
Other Deductions	394		0	0
Total Deductions		**1,490,832**	**0**	**1,490,832**
Other Adjustments to Taxable Income				
Charitable donations from Schedule 2	311	0	0	0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	0	0	0
Non-capital losses of preceding taxation years from Schedule 7-1	331	0	0	0
Net-capital losses of preceding taxation years from Schedule 7-1	332	0	0	0
Limited partnership losses of preceding taxation years from Schedule 4	335	0	0	0
Total Adjustments		**0**	**0**	**0**
Tax Adjustments to Accounting Income		**(67,699)**	**0**	**(67,699)**

Table 4-54 2012 Tax Calculations

Determination of Tax Adjustments to Accounting Income for 2012

Line Item	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Utility Amount
Additions:				
Interest and penalties on taxes	103	0	0	0
Amortization of tangible assets	104	812,762	0	812,762
Amortization of intangible assets	106	0	0	0
Recapture of capital cost allowance from Schedule 8	107	0	0	0
Gain on sale of eligible capital property from Schedule 10	108	0	0	0
Income or loss for tax purposes- joint ventures or partnerships	109		0	0
Loss in equity of subsidiaries and affiliates	110	0	0	0
Loss on disposal of assets	111	0	0	0
Charitable donations	112	0	0	0
Taxable Capital Gains	113	0	0	0
Political Donations	114	0	0	0
Deferred and prepaid expenses	116	0	0	0
Scientific research expenditures deducted on financial statements	118	0	0	0
Capitalized interest	119	0	0	0
Non-deductible club dues and fees	120		0	0
Non-deductible meals and entertainment expense	121		0	0
Non-deductible automobile expenses	122	0	0	0
Non-deductible life insurance premiums	123	0	0	0
Non-deductible company pension plans	124	0	0	0
Tax reserves beginning of year	125	0	0	0
Reserves from financial statements- balance at end of year	126	304,712	0	304,712
Soft costs on construction and renovation of buildings	127	0	0	0
Book loss on joint ventures or partnerships	205	0	0	0
Capital items expensed	206	0	0	0
Debt issue expense	208	0	0	0
Development expenses claimed in current year	212	0	0	0
Financing fees deducted in books	216	0	0	0
Gain on settlement of debt	220	0	0	0
Non-deductible advertising	226	0	0	0
Non-deductible interest	227	0	0	0
Non-deductible legal and accounting fees	228	0	0	0
Recapture of SR&ED expenditures	231	0	0	0
Share issue expense	235	0	0	0
Write down of capital property	236	0	0	0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	0	0	0
Interest Expensed on Capital Leases	290	0	0	0
Realized Income from Deferred Credit Accounts	291	0	0	0
Pensions	292	0	0	0
Non-deductible penalties	293	0	0	0
Debt Financing Expenses for Book Purposes	294		0	0
Other Additions (Apprenticeship Tax Credits)	295	0	0	0
Total Additions		**1,117,474**	**0**	**1,117,474**
Deductions:				
Gain on disposal of assets per financial statements	401		0	0
Dividends not taxable under section 83	402	0	0	0
Capital cost allowance from Schedule 8	403	1,261,977	0	1,261,977
Terminal loss from Schedule 8	404	0	0	0
Cumulative eligible capital deduction from Schedule 10	405	0	0	0
Allowable business investment loss	406	0	0	0
Deferred and prepaid expenses	409	0	0	0
Scientific research expenses claimed in year	411	0	0	0
Tax reserves end of year	413	0	0	0
Reserves from financial statements - balance at beginning of year	414	295,837	0	295,837
Contributions to deferred income plans	416	0	0	0
Book income of joint venture or partnership	305	0	0	0
Equity in income from subsidiary or affiliates	306	0	0	0
Interest capitalized for accounting deducted for tax	390	0	0	0
Capital Lease Payments	391	0	0	0
Non-taxable imputed interest income on deferral and variance accounts	392	0	0	0
Financing Fees for Tax Under S.20(1)(e)	393	0	0	0
Other Deductions	394	0	0	0
Total Deductions		**1,557,814**	**0**	**1,557,814**
Charitable donations from Schedule 2	311	0	0	0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	0	0	0
Non-capital losses of preceding taxation years from Schedule 7-1	331	0	0	0
Net-capital losses of preceding taxation years from Schedule 7-1	332	0	0	0
Limited partnership losses of preceding taxation years from Schedule 4	335	0	0	0
Total Adjustments		0	0	0
Tax Adjustments to Accounting Income		**(440,340)**	**0**	**(440,340)**

CAPITAL COST ALLOWANCE

LUI is providing Capital Cost Allowance continuity schedules for the 2011 Bridge Year and the 2012 Test Year as follows:

Table 4-55 2011 CCA / UCC Continuity Schedule

CCA Continuity Schedule (2011)

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	8,749,009			8,749,009	0	0	8,749,009	0	8,749,009	4%	349,960	8,399,049
2	Distribution System - pre 1988				0	0	0	0	0	0	6%	0	0
6	Buildings (No footings below ground)	10,016			10,016	0	0	10,016	0	10,016	10%	1,002	9,014
8	General Office/Stores Equip	44,361			44,361	100,000	0	144,361	50,000	94,361	20%	18,872	125,489
10	Computer Hardware/ Vehicles	540,964			540,964	50,000	0	590,964	25,000	565,964	30%	169,789	421,175
10.1	Certain Automobiles				0	0	0	0	0	0	30%	0	0
12	Computer Software	139,032			139,032	58,546	0	197,578	29,273	168,305	100%	168,305	29,273
3					0	0	0	0	0	0	5%	0	0
52					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	8%	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment				0	0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	1,352			1,352	0	0	1,352	0	1,352	45%	608	744
50	Computers & Systems Hardware acq'd post Mar 19/07	1,134			1,134	0	0	1,134	0	1,134	55%	624	510
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				0	0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	5,728,293			5,728,293	1,780,355	688,736	6,819,912	545,809	6,274,102	8%	501,928	6,317,984
	SUB-TOTAL - UCC	**15,214,161**	**0**	**0**	**15,214,161**	**1,988,901**	**688,736**	**16,514,326**	**650,082**	**15,864,243**		**1,211,089**	**15,303,237**

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**

0

Table 4-56 2011 CEC Continuity Schedule

Cumulative Eligible Capital Calculation				
Cumulative Eligible Capital				
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	0
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				0
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	0
Cumulative Eligible Capital Balance				0
CEC Deduction	7%			0
Cumulative Eligible Capital - Closing Balance				0

Table 4-57 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	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	8,399,049	0	0	8,399,049	0	0	8,399,049	0	8,399,049	4%	335,962	8,063,087
2	Distribution System - pre 1988	0	0	0	0	0	0	0	0	0	6%	0	0
6	Buildings (No footings below ground)	9,014	0	0	9,014	0	0	9,014	0	9,014	10%	901	8,113
8	General Office/Stores Equip	125,489	0	0	125,489	133,000	0	258,489	66,500	191,989	20%	38,398	220,091
10	Computer Hardware/ Vehicles	421,175	0	0	421,175	150,000	0	571,175	75,000	496,175	30%	148,852	422,322
10.1	Certain Automobiles	0	0	0	0	0	0	0	0	0	30%	0	0
12	Computer Software	29,273	0	0	29,273	250,000	0	279,273	125,000	154,273	100%	154,273	125,000
3		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	744	0	0	744	0	0	744	0	744	45%	335	409
50	Computers & Systems Hardware acq'd post Mar 19/07	510	0	0	510	0	0	510	0	510	55%	281	230
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	6,604,733			6,604,733	1,420,000	0	8,024,733	710,000	7,314,733	8%	585,179	7,439,554
	SUB-TOTAL - UCC	**15,589,987**	**0**	**0**	**15,589,987**	**1,953,000**	**0**	**17,542,987**	**976,500**	**16,566,487**		**1,264,181**	**16,278,806**
						305,901	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 4-58 2012 CEC Continuity Schedule

Cumulative Eligible Capital Calculation

Cumulative Eligible Capital				0
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	0
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				0
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	0
Cumulative Eligible Capital Balance				0
CEC Deduction	7%			0
Cumulative Eligible Capital - Closing Balance				0

APPENDIX B PROCUREMENT POLICY

POLICY AND PROCEDURES	DEPARTMENT: ADMINISTRATION
Lakefront Utility Services Inc.	SUBJECT: PROCUREMENT POLICY #: 2011-0201 ISSUE DATE: February 1st 2011 PAGES: Page 1 of 4

ADM 4.1.0 PURPOSE

4.1.1 To set forth the policy of the corporation regarding the approval procedure for purchasing capital and operational expenditures.

ADM 4.2.0 POLICY STATEMENT

4.2.1 It is the policy of Lakefront Group of Companies represented by Lakefront Utility Services Inc. (LUSI) to set up procedures for the purchasing of supplies, materials and other services on behalf of LUSI and its affiliates.

ADM 4.3.0 PURCHASE ORDER CREATION PROCESS

4.3.1 All requests for the purchase of goods or services must be submitted on a Purchasing Form, which when authorized and approved by the appropriate signing authorities and assigned a valid number, becomes an official Purchase Order.

4.3.2 In an emergency, a Supervisor may place a verbal order which must be followed by a official Purchase Order as soon as practicable.

ADM 4.4.0 RESPONSIBILITIES

4.4.1 Department Manager's Responsibility's

The Department Manager is responsible for reporting, in writing, to the President or Vice President, all instances of unsatisfactory vendor performance.

4.4.2 Staff's Responsibilities

All staff is responsible for following the Purchasing Policy as outlined within, for ensuring that all items purchased meet the all current Regulatory Standards and/ or an approved Electrical Standards as per Ontario Regulation 22/04

POLICY AND PROCEDURES	DEPARTMENT: ADMINISTRATION
Lakefront Utility Services Inc.	SUBJECT: PROCUREMENT POLICY #: 2011-0201 ISSUE DATE: February 1st 2011 PAGES: Page 2 of 4

ADM 4.5.0 APPROVAL PROCEDURE & LEVELS

4.5.1 Purchasing Forms will be approved by the appropriate authority level as per *Table 1 and Table 2* below, validated for appropriateness of expenditure, verified against the current approved Budgets and checked for account coding accuracy. All invoices will be matched to the corresponding approved purchase order by the Finance Department.

4.5.2 Purchases are not to be divided to circumvent any thresholds in this policy.

Table 1 Approved Budget Purchases

Supervisor	Approval of purchase orders not to exceed $ 1,000
Manager	Approval of purchase orders not to exceed $ 5,000
Corporate Officers	Approval of purchase orders not to exceed $ 25,000
Vice- President	Approval of purchase orders not to exceed $ 50,000
President	Approval of purchase orders not to exceed $100,000
President **and** VP	Approval of purchase orders not to exceed $150,000

Purchases over $150,000 require additional authorization by the Chair of HOLDCO.

Table 2 Purchases not included in Approved Budget

Supervisor	Approval of purchase orders not to exceed $ 250
Manager	Approval of purchase orders not to exceed $ 1000
Corporate Officers	Approval of purchase orders not to exceed $ 2,000
Vice- President	Approval of purchase orders not to exceed $ 10,000
President	Approval of purchase orders not to exceed $ 15,000
President **and** VP	Approval of purchase orders not to exceed $ 25,000

Purchases over $25,000 require additional authorization by the appropriate Board.

4.5.3 Purchase of miscellaneous items under a value of $250 do not require a purchase order but do require approval and account coding by appropriate supervisor.

4.5.4 Rental of equipment does not require a purchase order but does require the associated work order. The invoice will contain the work order number will be approved

POLICY AND PROCEDURES	DEPARTMENT: ADMINISTRATION
Lakefront Utility Services Inc.	SUBJECT: PROCUREMENT POLICY #: 2011-0201 ISSUE DATE: February 1st 2011 PAGES: Page 3 of 4

at the time it is received. Work order number must be recorded on third party documentation.

ADM 4.6.0 PURCHASES PAID OUT OF PETTY CASH

4.6.1 Purchases for goods or services costing less than $50 total can be paid out of Petty Cash when authorized by the appropriate supervisor.

ADM 4.7.0 CREDITCARD PURCHASES

4.7.1 Authorization from the appropriate supervisor is required for purchases over $250. Senior management do not require authorization for amounts up to their limits of authority and the statements must be reviewed and approved by their immediate supervisor.

ADM 4.8.0 PURCHASES COSTING BETWEEN $250 AND $15,000

4.8.1 All purchases over $250 require a Purchase Order, signed by the appropriate Authority. Purchaser will use his/her discretion in selecting the suppliers from whom to choose based on best value. For all purchases, competitive prices must be obtained and recorded.

ADM 4.9.0 PURCHASES COSTING BETWEEN $15,000 AND $25,000

4.9.1 When the total expenditure for goods or services is between $15,000 and $25,000, quotations will be solicited from at least three (3) suppliers.

4.9.2 The quotation process may be omitted under the following conditions:

- Emergency situation declared by the President or his designate;
- Sole Source Purchases must be approved by two (2) Corporate Officers.

ADM 4.10.0 Purchases Costing over $25,000

4.10.1 Tenders, Request for Proposals, Request for Quotations will be required when the total expenditure for goods or services is expected to exceed $25,000.

POLICY AND PROCEDURES	DEPARTMENT: ADMINISTRATION
Lakefront Utility Services Inc.	SUBJECT: PROCUREMENT POLICY #: 2011-0201 ISSUE DATE: February 1st 2011
	PAGES: Page 4 of 4

ADM 4.11.0 EXCLUSIONS TO PROCUREMENT PROCESS

4.11.1 The following items are not subject to this Procurement Policy:

1.0 Purchasing Card Purchases
2.0 Cheque Requisition
3.0 Training and Education
- a) Conferences
- b) Courses
- c) Seminars
- d) Conventions
- e) Memberships
- f) Periodicals
- g) Magazines
- h) Subscriptions
- i) Staff Training
- j) Staff Development
- k) Staff Workshops

4.0 Refundable Employee Expenses
- a) Meal Allowances
- b) Travel Expenses
- c) Hotel Accommodation
- d) Mileage

5.0 General Expenses
- a) Licences, insurance (vehicles, etc.)
- b) Banking and underwriting services where covered by agreements
- c) Real estate including land, buildings, leasehold interests, easements, encroachments and licences
- d) Items of a confidential nature
- e) Professional and special services, including appraisals, medical, etc.
- f) Freight charges
- g) IESO Invoice
- h) Debt Retirement Charge Remittance
- i) ESA Inspection Charges
- j) OEB Fixed Costs
- k) Insurance Employee benefits (Pension, Health Insurance, etc)
- l) Taxes
- m) Customer refunds
- n) External Audit Invoices
- o) Legal expenses

6.0 Utilities
- a) Postage
- b) Water and sewage charges
- c) Hydro
- d) Natural Gas
- e) Internet Service
- f) Telephone Service

APPENDIX C LUI DETAILED TAX RETURNS

2008 LUI TAX RETURN

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

Schedule 200

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Ontario (for tax years ending before 2009), Quebec, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, and paragraphs mentioned on this return refer to the *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or the T2 Corporation – Income Tax Guide (T4012).

055 Do not use this area

Identification

Business number (BN) 001 11111 1118 RC 0001

Corporation's name

002 Lakefront Utilities Inc.

Address of head office

Has this address changed since the last time you filed your T2 return? 010 ☐ Yes ☒ No

(If **yes**, complete lines 011 to 018)

011 207 Division Street

012

City: 015 Cobourg — Province, territory, or state: 016 ON

Country (other than Canada): 017 — Postal code/Zip code: 018 K9A 4L3

Mailing address (If different from head office address)

Has this address changed since the last time you filed your T2 return? 020 ☐ Yes ☒ No

(If **yes**, complete lines 021 to 028)

021 c/o

022 207 Division Street

023

City: 025 Cobourg — Province, territory, or state: 026 ON

Country (other than Canada): 027 — Postal code/Zip code: 028 K9A 4L3

Location of books and records

Has the location of books and records changed since the last time you filed your T2 return? 030 ☐ Yes ☒ No

(If **yes**, complete lines 031 to 038)

031 207 Division Street

032

City: 035 Cobourg — Province, territory, or state: 036 ON

Country (other than Canada): 037 — Postal code/Zip code: 038 K9A 4L3

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

To which tax year does this return apply?

From 060 2008/01/01 to 061 2008/12/31

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? 063 ☐ Yes ☒ No

If **yes**, provide the date control was acquired 065

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1) ? 066 ☐ Yes ☒ No

Is the corporation a professional corporation that is a member of a partnership? 067 ☐ Yes ☒ No

Is this the first year of filing after:

Incorporation? 070 ☐ Yes ☒ No
Amalgamation? 071 ☐ Yes ☒ 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 ☐ Yes ☒ No

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? 076 ☐ Yes ☒ No

Is this the final return up to dissolution? 078 ☐ Yes ☒ No

Is the corporation a resident of Canada? 080 ☒ Yes ☐ 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 ☐ Yes ☒ No

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085 1 ☐ Exempt under paragraph 149(1)(e) or (l)
2 ☐ Exempt under paragraph 149(1)(j)
3 ☐ Exempt under paragraph 149(1)(t)
4 ☐ Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules - Answer the following questions. For each *Yes* response, **attach** to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **Yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		-----
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210		10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	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?	255		92 *

*** We do not print this schedule.**

Attachments - Continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256	☐	T1134-A
Did the corporation have any controlled foreign affiliates?	258	☐	T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259	☐	T1135
Did the corporation transfer or loan property to a non-resident trust?	260	☐	T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261	☐	T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262	☐	T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263	☐	T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264	☐	T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	☒	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266	☐	T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267	☐	T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	☒	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269	☐	54

Additional information

Is the corporation inactive?	280	1 Yes ☐	2 No ☒
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281	1 Yes ☐	2 No ☒
What is the corporation's major business activity? (Only complete if **yes** was entered at line 281.)	282		
If the major business activity involves the resale of goods, show whether it is wholesale or retail	283	1 Wholesale ☐	2 Retail ☐

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Distribution of Electricity	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes ☐	2 No ☒
Did the corporation emigrate from Canada during the tax year?	292	1 Yes ☐	2 No ☒
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		
If the corporation's major business activity is construction, did you have any sub-contractors during the tax year?	295	1 Yes ☐	2 No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI		300	1,758,516	A
Deduct: Charitable donations from Schedule 2	311			
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction *	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal				B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			1,758,516	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions		355		D
Taxable income (amount C **plus** amount D)		360	1,758,516	
Income exempt under paragraph 149(1)(t)		370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724 on page 8.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7		400	1,758,516	A
Taxable income from line 360 on page 3, **minus** 10/3 of the amount on line 632 on page 7, **minus** 3 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	1,758,516	B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

$300,000 x Number of days in the tax year in 2006 / Number of days in the tax year	366	=	1	
$400,000 x Number of days in the tax year after 2006 and before January 1, 2009 / Number of days in the tax year	366 / 366	= 400,000	2	
$500,000 x Number of days in the tax year after 2008 / Number of days in the tax year	366	=	3	
Add amounts at lines 1, 2 and 3		400,000	4	
Business limit (see notes 1 and 2 below)		410	400,000	C

Notes: 1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 400,000 X 415 8,740 D / 11,250 = 310,756 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0")		425	89,244	F

Small business deduction

Amount A, B, C, or F whichever is the least	89,244	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	366	x 16% =	5
Amount A, B, C, or F whichever is the least	89,244	Number of days in the tax year after Dec.31, 2007 / Number of days in the tax year	366 / 366	x 17% = 15,171	6
Total of amounts 5 and 6 - enter on line 9 of page 7				430 15,171	G

1

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)]				435	H
Amount H	x	Number of days in the tax year in 2006 / Number of days in the tax year	366 x 5% =		I
Amount H	x	Number of days in the tax year in 2007 / Number of days in the tax year	366 x 7% =		J

Note: Resource deduction is no longer available for tax years starting after December 31, 2006.

Resource deduction – total of amounts I and J — 438 K

Enter amount K on line 10 of page 7.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3				1,758,516	A
Lesser of amounts V and Y from Part 9 of Schedule 27			B		
Amount QQ from Part 13 of Schedule 27			C		
Taxable resource income from line 435 on page 4			D		
Amount used to calculate the credit union deduction (from Schedule 17)			E		
Amount on line 400, 405, 410, or 425 on page 4, whichever is the least			89,244 F		
Aggregate investment income from line 440 of page 6			G		
Total of amounts B, C, D, E, F, and G			89,244 ▶	89,244	H
Amount A **minus** amount H (if negative, enter "0")				1,669,272	I
Amount I 1,669,272	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	366 x 7% =		J
Amount I 1,669,272	x	Number of days in the tax year after Dec. 31, 2007 and before Jan. 1, 2009 / Number of days in the tax year	366 / 366 x 8.5% =	141,888	K
Amount I 1,669,272	x	Number of days in the tax year after Dec. 31, 2008 and before January 1, 2010 / Number of days in the tax year	366 x 9% =		L
General tax reduction for Canadian-controlled private corporations - total of amounts J, K, and L				141,888	M

Enter amount M on line 638 of page 7.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation, and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 on page 3 (for tax years starting after May 1, 2006, Amount Z on page 3)					N
Lesser of amounts V and Y from Part 9 of Schedule 27			O		
Amount QQ from Part 13 of Schedule 27			P		
Taxable resource income from line 435 on page 4			Q		
Amount used to calculate the credit union deduction (from Schedule 17)			R		
Total of amounts O, P, Q, and R			▶		S
Amount N **minus** amount S (if negative, enter "0")					T
Amount T	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	366 x 7% =		U
Amount T	x	Number of days in the tax year after Dec. 31, 2007 and before Jan. 1, 2009 / Number of days in the tax year	366 x 8.5% =		V
Amount T	x	Number of days in the tax year after Dec. 31, 2008 and before Jan. 1, 2010 / Number of days in the tax year	366 x 9% =		W
General tax reduction - total of amounts U, V and W					X

Enter amount X on line 639 of page 7.

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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			1,758,516		
Deduct:					
Amount on line 400, 405, 410, or 425 on page 4, whichever is the least		89,244			
Foreign non-business income tax credit from line 632 of page 7	x 25/9 =				
Foreign business income tax credit from line 636 of page 7	x 3 =				
		89,244	89,244		
			1,669,272	X 26 2/3% =	445,139 D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8)			335,325		
Deduct: Corporate surtax from line 600 of page 7					
Net amount			335,325		335,325 E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least				450	0 F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	460			
Deduct: Dividend refund for the previous tax year	465			G
Add the total of:				
Refundable portion of Part I tax from line 450 above				
Total Part IV tax payable from Schedule 3				
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480			H
Refundable dividend tax on hand at the end of the tax year - Amount G **plus** amount H			485	0

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	400,000	X 1/3	133,333 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 of page 8)			0

1

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	668,236 A

Corporate surtax calculation

Base amount from line A above		668,236	1
Deduct:			
10% of taxable income (line 360 or amount Z, whichever applies) from page 3		175,852	2
Investment corporation deduction from line 620 below			3
Federal logging tax credit from line 640 below			4
Federal qualifying environmental trust tax credit from line 648 below			5
For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:			
28% of taxable income from line 360 on page 3	a		
28% of taxed capital gains	b		6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)	335,325 c		
Total of lines 2 to 6		175,852	7
Net amount (line 1 **minus** line 7)		492,384	8

Corporate surtax*

Line 8 492,384 x (Number of days in the tax year before January 1, 2008 ___ / Number of days in the tax year 366) x 4% = **600** ___ B

*The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31 **602** ___ C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income (if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			i
Taxable income from line 360 on page 3	1,758,516		
Deduct:			
Amount on line 400, 405, 410, or 425 of page 4, whichever is the least	89,244		
Net amount	1,669,272 ▶	1,669,272	ii

Refundable tax on CCPC's investment income – 6 2/3% of whichever is less: amount i or ii **604** ___ D

Subtotal (**add** lines A, B, C, and D) 668,236 E

Deduct:

Small business deduction from line 430 on page 4		15,171	9
Federal tax abatement	**608**	175,852	
Manufacturing and processing profits deduction from Schedule 27	**616**		
Investment corporation deduction	**620**		
(taxed capital gains **624** ___)			
Additional deduction – credit unions from Schedule 17	**628**		
Federal foreign non-business income tax credit from Schedule 21	**632**		
Federal foreign business income tax credit from Schedule 21	**636**		
Resource deduction from line 438 on page 4			10
General tax reduction for CCPCs from amount M on page 5	**638**	141,888	
General tax reduction from amount X on page 5	**639**		
Federal logging tax credit from Schedule 21	**640**		
Federal political contribution tax credit	**644**		
Federal political contributions **646** ___			
Federal qualifying environmental trust tax credit	**648**		
Investment tax credit from Schedule 31	**652**		
Subtotal		332,911 ▶	332,911 F

Part I tax payable – Line E **minus** line F 335,325 G

Enter amount G on line 700 of page 8.

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Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	335,325
Part I.3 tax payable from Schedule 33, 34, or 35	704	
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		335,325

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 Ontario [for tax years ending before 2009], Quebec, and Alberta)	760	
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765	
Total tax payable	770	335,325 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	
Total credits	890	B

Refund Code 894 ☐ Overpayment

Balance (line A minus line B) 335,325 I

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 335,325
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 ☐ NA ☐

Certification

I, 950 Cunningham (Last name) 951 Stewart (First name) 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 further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2009/04/30 (Date) Signature of the authorized signing officer of the corporation 956 (905) 372-2193 (Telephone number)

Is the contact person the same as the authorized signing officer? If *no*, complete the information below. 957 1 Yes ☒ 2 No ☐

958 Name 959 ( ) - Telephone number

Language of correspondence - Langue de correspondance

990 Language of choice/Langue de choix 1 English / Anglais ☒ 2 Français / French ☐

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES — Schedule 1

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the *T2 Corporation Income Tax Guide*.
- Please provide us with the applicable details in the identification area, and complete the applicable lines that contain a numbered black box. You should report amounts in accordance with the Generally Accepted Accounting Principles (GAAP).
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items per financial statements			A	1,047,442
Add:				
Provision for income taxes - current	101	557,613		
Amortization of tangible assets	104	838,632		
Reserves from financial statements - balance at the end of the year	126	257,375		
Total of fields 101 to 199	500	1,653,620	▶	1,653,620
Deduct:				
Capital cost allowance from Schedule 8	403	698,052		
Reserves from financial statements - balance at the beginning of the year	414	244,494		
Total of fields 401 to 499	510	942,546	▶	942,546
Net income (loss) for income tax purposes - enter on line 300 on page 3 of the T2 return				1,758,516

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DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

Schedule 3

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid for purposes of a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act*.
- A recipient corporation is connected with a payer corporation at any time in a taxation year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- If you need more space, continue on a separate schedule.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the sections about Schedule 3 in the *T2 Corporation Income Tax Guide*.

Part 1 - Dividends received during the taxation year

Do not include dividends received from foreign non-affiliates.

A		B	C	D	E	F
Name of payer corporation 200		Connected? 205	Dividends from foreign source?	Dividends subject to Part IV tax?	Dividends deductible from income under s.112, 113, and 138(6) 240	Non-taxable dividends deductible under section 83 230

Note: If your corporation's taxation year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one taxation year of the payer corporation. If so, use a separate line to provide the information for each taxation year of the payer corporation.

Complete if payer corporation is connected and a private or subject corporation					GRIP / LRIP	
G	H	I	J	K		
Business number 210	Taxation year end of the payer corporation in which the dividend was paid 220	Total taxable dividends paid by connected payer corporation 250	Dividend refund of the connected payer corporation 260	Part IV tax before deductions ** 270	Column E deduction type	Indicate eligible dividends
RC		0	0	0		

Total non-taxable dividends deductible under section 83 _____

Total dividends deductible from income under sections 112, 113, and 138(6) _____

** For dividends received from non-connected corporations, Part IV tax = the amount entered in column E x 1/3
For dividends received from connected corporations, do the following calculation: Part IV tax = column E x column J / column I
Life insurers are not subject to Part IV tax on subsection 138(6) dividends.
Public corporations (other than subject corporations) do not need to calculate Part IV tax.

Part 2 - Calculation of Part IV tax payable

Part IV tax before deductions (total of column K 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 0

DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

Part 3 - Taxable dividends paid in the taxation year for purposes of a dividend refund

A Name of connected recipient corporation 400	B Business number 410	C Taxation year end of connected recipient corporation in which the dividend was received 420	D Taxable dividends paid to connected corporations 430
Town of Cobourg Holdings Inc.	NR	2008/12/31	400,000
	RC		
		Total	400,000

Note

If your corporation's taxation year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one taxation year of the recipient corporation. If so, use a separate line to provide the information for each taxation year of the recipient corporation.

Total taxable dividends paid in the taxation year to other than connected corporations	450	
Total taxable dividends paid in the taxation year for the purposes of a dividend refund (total of column D above plus line 450)	460	400,000

Part 4 - Total dividends paid in the taxation year

Complete this part if the total taxable dividends paid in the taxation year for purposes of a dividend refund (line 460 above) is different from the total dividends paid in the taxation year.

	500	
Deduct:		
Dividends paid out of capital dividend account	510	
Capital gains dividends	520	
Dividends paid on shares described in subsection 129(1.2)	530	
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540	
Subtotal		
Total taxable dividends paid in the taxation year for purposes of a dividend refund		0

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CAPITAL COST ALLOWANCE

Schedule 8

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 **200**	2 UCC at start of year **201**	3 Cost of additions in the year **203**	4 Net adjustments **205**	5 Proceeds of dispositions in the year **207**	7 Adjustment for additions (1/2 x (col 3 - 5)) **211**	8 Base amount for CCA	9 Rate % **212**	10 Recapture of CCA **213**	11 Terminal loss **215**	12 CCA for the year (col 8 x 9 or a lower amount) **217**	13 UCC at the end of the year **220**
1	837,187	7,981			3,991	841,177	4			33,647	811,521
1	9,621,348					9,621,348	4			384,854	9,236,494
10	236,205	284,467			142,234	378,438	30			113,531	407,141
10	14,571					14,571	30			4,371	10,200
12	22,008	47,532			19,573	49,967	100			49,967	19,573
45	8,127					8,127	45			3,657	4,470
47	840,061	884,188			442,094	1,282,155	8			102,572	1,621,677
50	6,121	3,924			1,962	8,083	55			4,446	5,599
8		3,559			1,780	1,779	20			356	3,203
6		13,017			6,509	6,508	10			651	12,366
Totals	11,585,628	1,244,668			618,143	12,212,153				698,052	12,132,244

LAKEFRONT UTILITIES INC.
EB-2011-0250
EXHIBIT 4
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RELATED AND ASSOCIATED CORPORATIONS

Schedule 9

This form is to be completed by a corporation having one or more of the following:

- related corporation(s)
- associated corporation(s)

Name	Country (if not Canada)	Business # (Canadian corporation only)	Code note 1	Common shares		Preferred shares		Book value of capital stock
				# owned	% owned	# owned	% owned	
100	200	300	400	500	550	600	650	700
Town of Cobourg Holdings Inc.		NR	1					
Lakefront Utilities Services Inc.		NR	3					
Cobourg Networks Inc.		NR	3					
Note 1 : Enter the code number of the relationship that applies: 1- Parent 2 - Subsidiary 3 - Associated 4 - Related, but not associated								

LAKEFRONT UTILITIES INC.
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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, including non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:
1 - Associated for purposes of allocating the business limit (unless code 5 applies)
2 - CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction.
3 - Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 - Associated non-CCPC
5 - Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2004	$225,001 to $250,000
2005	$250,001 to $300,000
2006	maximum $300,000
2007	$300,001 to $400,000

If the calendar year to which this agreement applies is after 2007, ensure that the total at line A does not exceed $400,000.

Allocating the business limit

Date filed (do not use this area) **025** _____

Enter the calendar year to which the agreement applies **050** 2008

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? **075** ☐ 1 Yes ☒ 2 No

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Association code **300**
1	Lakefront Utilities Inc.	11111 1118 RC 0001	1
2	Town of Cobourg Holdings Inc.	NR	1
3	Lakefront Utilities Services Inc.	NR	1
4	Cobourg Networks Inc.	NR	1

Allocate business limit using: ☒ % ☐ $

	Taxation year Start	Taxation year End	4 Business limit for the year (before allocation) $	Allocating business limit: 5 Percentage of the business limit (%) **350**	6 Business limit allocated $ **400**	7 Gross Part I.3 tax for business limit reduction
1	2008/01/01	2008/12/31	400,000	100.000	400,000	
2	2008/01/01	2008/12/31	400,000			
3	2008/01/01	2008/12/31	400,000			
4	2008/01/01	2008/12/31	400,000			
TOTALS				100.000	A 400,000	

If the taxation year of the corporation filing this form is less than 51 weeks, enter the prorated business limit in this box. $ 400,000

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AGREEMENT AMONG ASSOCIATED CCPCs TO ALLOCATE THE BUSINESS LIMIT

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, 2007, 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 $400,000 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.

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PART I.3 TAX ON LARGE CORPORATIONS

Schedule 33

- File this schedule if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- Even if there is no Part I.3 tax payable for the days in the tax year that are after 2005, you must still complete this schedule (except parts 5 and 9).
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms "financial institution", "long-term debt" and "reserves".
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- No Part I.3 tax is payable for a taxation year by a corporation that was:
  1) bankrupt [as defined by subsection 128(3)] at the end of the year;
  2) a deposit insurance corporation throughout the year, as defined by subsection 137.1(5), or deemed to be a deposit insurance corporation by subsection 137.1(5.1);
  3) exempt from tax under section 149 throughout the year on all of its taxable income;
  4) neither resident in Canada nor carrying on a business through a permanent establishment in Canada at any time in the year; or
  5) a corporation described in subsection 136(2) throughout the year, the principal business of which was marketing (including any related processing) natural products belonging to or acquired from its members or customers.
- File the completed Schedule 33 with the *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- This schedule may contain changes that had not yet become law at the time of printing.

If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, "Taxable capital employed in Canada."

Part 1 - Capital

Add the following amounts at the end of the year:				
Reserves that have not been deducted in computing income for the year under Part I	101			
Capital stock (or members' contributions if incorporated without share capital)	103	5,293,376		
Retained earnings	104	2,041,773		
Contributed surplus	105			
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108	7,000,000		
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109			
Any dividends declared but not paid by the corporation before the end of the year	110			
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111	599,992		
Proportion of the amount, if any, by which the total of all amounts (see note below) for the partnership of which the corporation is a member at the end of the year exceeds the amount of the partnership's deferred unrealized foreign exchange losses	112			
Subtotal		14,935,141	14,935,141	A
Deduct the following amounts:				
Deferred tax debit balance at the end of the year	121			
Any deficit deducted in computing its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122			
Any amount deducted under subsection 135(1) in computing income under Part I for the year, as long as the amount may reasonably be regarded as being included in any of lines 101 to 112 above	123			
The amount of deferred unrealized foreign exchange losses at the end of the year	124			
Subtotal				B
Capital for the year (amount A minus amount B) (if negative, enter "0")			190 14,935,141	

PART I.3 TAX ON LARGE CORPORATIONS

Part 2 - Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	863,194
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend receivable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim, or similar obligation of, a partnership all of the members of which, throughout the year, were other corporations (other than financial institutions) that were not exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)]	406	
An interest in a partnership	407	
Investment allowance for the year (add lines 401 to 407)	490	863,194

Part 3 - Taxable capital

Capital for the year (line 190)		14,935,141	C
Deduct: Investment allowance for the year (line 490)		863,194	D
Taxable capital for the year (amount C minus amount D) (if negative, enter "0")	500	14,071,947	

Part 4 - Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500)		Taxable income earned in Canada / Taxable income			=	690 **Taxable capital employed in Canada**
14,071,947	x	1,758,516 / 1,758,516	610	1,758,516	=	14,071,947

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business it carried on during the year through a permanent establishment in Canada		701	
Deduct the following amounts:			
Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada	711		
Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada	712		
Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada	713		
Total deductions (add lines 711, 712, and 713)			E
Taxable capital employed in Canada (line 701 minus amount E) (if negative, enter "0")		790	

PART I.3 TAX ON LARGE CORPORATIONS

Part 5 - Calculation of gross Part I.3 tax

If the tax year starts after 2005, do not complete this part.

Taxable capital employed in Canada (line 690 or 790, whichever applies)					14,071,947
Deduct: Capital deduction claimed for the year (enter $50,000,000 or, for related corporations, the amount allocated on Schedule 36)					50,000,000
Excess of taxable capital employed in Canada over capital deduction				811	
Line 811 _____ x	Number of days in the tax year in 2004 / Number of days in the tax year	366	x 0.002 =		F
Line 811 _____ x	Number of days in the tax year in 2005 / Number of days in the tax year	366	x 0.00175 =		G

Note: The Part I.3 tax rate is reduced to 0% for the days in the tax year that are after 2005.

Subtotal (add amounts F and G) H

Where the tax year of a corporation is less than 51 weeks, calculate the amount of gross Part I.3 tax as follows:

Amount H _____ X Number of days in the year (_____) / 365 = I

Gross Part I.3 tax (amount H or I, whichever applies) 820

Part 6 – Calculation of gross Part I.3 tax for purposes of the unused surtax credit

Taxable capital employed in Canada (line 690 or 790, whichever applies)				14,071,947 J
Deduct: Capital deduction claimed for the year (enter $50,000,000 or, for related corporations, the amount allocated on Schedule 36)	801	50,000,000	x 1/5 =	10,000,000 K
Excess (amount J minus amount K) (if negative, enter "0")				4,071,947 L
Amount L 4,071,947 x 0.00225 =				9,162 M

Where the tax year of a corporation is less than 51 weeks, calculate the amount of gross Part I.3 tax for purposes of the unused surtax credit as follows:

Amount M _____ x Number of days in the year (_____) / 365 = N

Gross Part I.3 tax for purposes of the unused surtax credit (amount M or N, whichever applies) 821 9,162

PART I.3 TAX ON LARGE CORPORATIONS

Part 7 - Calculation of current-year surtax credit available

- Corporations can claim a credit against their Part I.3 tax for the amount of Canadian surtax payable for the year. This is called the surtax credit.
- Any unused surtax credit can be carried back three years or carried forward seven years. Unused surtax credits must be applied in order of the oldest first.
- Refer to subsection 181.1(7) when calculating the amount deductible for a corporation's unused surtax credits where control of the corporation has been acquired between the year in which the credits arose and the year in which you want to claim them.

For a corporation that was a non-resident of Canada throughout the year, enter amount **a** or **b** at line O, whichever is less:

a) line 600 from the T2 return			**a**	
b) line 700 from the T2 return			**b**	O

In any other case, enter amount **c** or **d** at line P, whichever is less:

c) line 600 from the T2 return	x (line 690 + line 500)	=		**c**	
d) line 700 from the T2 return			335,325	**d**	P

Current-year surtax credit available (amount O or P, whichever applies) **830**

Part 8 - Calculation of current-year unused surtax credit

Current-year surtax credit available (line 830)		
Less: Gross Part I.3 tax for purposes of the unused surtax credit (line 821)		9,162
Current-year unused surtax credit (if negative, enter "0")	**850**	

Enter this amount at line 600 on Schedule 37.

Part 9 - Calculation of net Part I.3 tax payable

If the tax year starts after 2005, do not complete this part.

Gross Part I.3 tax (line 820)			Q
Deduct:			
Current-year surtax credit applied (line 820 or 830, whichever is less)	**861**		
Unused surtax credit from previous years applied (amount from line 320 on Schedule 37)	**862**		
Subtotal (cannot be more than amount on line 820)			R
Net Part I.3 tax payable (amount Q minus amount R)	**870**		

Enter this amount at line 704 of the T2 return.

Part 10 - Calculation for purposes of the small business deduction

This part is applicable only to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (line 690 or 790, whichever applies)	14,071,947	S
Deduct:		
Capital deduction claimed for the year (enter $10,000,000)	10,000,000	T
Excess (amount S minus amount T) (if negative, enter "0")	4,071,947	U
Gross Part I.3 tax for purposes of the small business deduction (Amount U x 0.00225)	9,162	V

Enter this amount at line 415 of the T2 return.

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Schedule 36

AGREEMENT AMONG RELATED CORPORATIONS - PART I.3 TAX

- Corporations related at any time in their tax year that ends in the calendar year of the agreement should use this schedule to allocate the capital deduction of $50,000,000 among the members of the related group if:
  - any member applies the surtax credit against Part I.3 tax in a tax year starting before January 1, 2006; or
  - any member wants to carry back an unused surtax credit against Part I.3 tax to a tax year starting before January 1, 2006.
- According to subsection 181.5(7) of the *Income Tax Act*, a Canadian-controlled private corporation is not considered to be related to another corporation for the capital deduction unless it is also associated with that corporation.
- In cases where a related corporation has more than one tax year ending in a calendar year, it has to file this agreement for each of those tax years.
- According to subsection 181.5(5), where a corporation has more than one tax year ending in the same calendar year and is related in two or more of those tax years to another corporation that has a tax year ending in that calendar year, the capital deduction of the first corporation for each such tax year at the end of which it is related to the other corporation is an amount equal to its capital deduction for the first such tax year.
- Any corporation in the related group may file this agreement on behalf of the group. However, if an agreement is not already on file with us when we assess any of the returns for a tax year ending in the calendar year of the agreement, we will ask for one.

Agreement

Date filed (do not use this area)	010	
Is this an amended agreement?	020	☐ 1 Yes ☒ 2 No
Calendar year to which the agreement applies	030	2008

Note: This agreement must include all the information indicated below for all members of the related group, including members to which no amount of capital deduction is allocated for the year. However, any member that is exempt from Part I.3 tax under subsection 181.1(3) of the *Income Tax Act* does not have to be included.

Name of each corporation that is a member of the related group 200	Business number (if a corporation is not registered, enter "NR") 300	Allocation of capital deduction for the year $ 400
Lakefront Utilities Inc.	11111 1118 RC 0001	50,000,000
Town of Cobourg Holdings Inc.	NR	0
Lakefront Utilities Services Inc.	NR	0
Cobourg Networks Inc.	NR	0
Total (cannot be more than $50,000,000)		50,000,000

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SHAREHOLDER INFORMATION

Schedule 50

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

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 (If a trust number is not available, enter "NA") * 350	Percentage common shares 400	Percentage preferred shares 500
Town of Cobourg Holdings Inc.	NR			100.000	
	RC				

* For a taxation year commencing before January 1, 2004, if the shareholder is a trust, enter NR at field 200 or NA at field 300. Do not enter a trust number in field 350.

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GENERAL RATE INCOME POOL (GRIP) CALCULATION

Schedule 53

- 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.

Part 1 – Calculation of general rate income pool (GRIP)

If the corporation's tax year includes January 1, 2006, complete "Part 5 – GRIP addition for 2006" and then line 050. Otherwise, complete line 100.

GRIP addition for 2006 (the greater of amount QQ from Part 5 or "0")				50	0 A
GRIP at the end of the previous tax year				100	848,314 B
Taxable income for the year (DICs enter "0")*			110 1,758,516 C		
Income for the credit union deduction* (amount E in Part 3 of Schedule 17)	120	0			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less*	130	89,244			
Subtotal (**add** lines 120 and 130)		89,244	89,244 D		
For a CCPC, aggregate investment income (line 440 of the T2 return)*		0 E			
Line C **minus** line D (if negative enter "0")		1,669,272 F			
Amount from line E of F, whichever is less			140 0 G		
Income taxable at the general corporate rate (line C **minus** lines D and G)			150 1,669,272		
After-tax income (line 150 **multiplied by** 68%)				190	1,135,105 H
Eligible dividends received during the year by the corporation from:					
Amounts entered on S3			0		
Any other amounts to include			+ 0		
Eligible dividends received in the tax year			200 0		
Dividends deductible under section 113 received in the tax year			210 0		
Subtotal (**add** lines 200 and 210)			0		0 I
GRIP addition:					
Becoming a CCPC (line PP from Part 4)			220 0		
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)			230 0		
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)			240 0		
Subtotal (**add** lines 220, 230, and 240)			0	290	0 J
Subtotal (**add** lines A or B (as applicable), H, I, and J)					1,983,419 K
Eligible dividends paid in the previous tax year			300 0		
Excessive eligible dividend designations made in the previous tax year			310 0		
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310. Subtotal (line 300 **minus** line 310)			0		0 L
GRIP before adjustment for specified future tax consequences (line k minus line L) (amount can be negative)				490	1,983,419
Total GRIP adjustment for specified future tax consequences to previous tax years (amount Y from Part 2)				560	0
GRIP at the end of the tax year (line 490 minus line 560)				590	1,983,419

Enter this amount on line 160 on Schedule 55.

* **Note:** For lines 110, 120, 130, and E, 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.

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560 of page 1 or leave it blank.

First previous tax year

Taxable income before specified future tax consequences from the current tax year.			0 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)	0 K1			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 L1			
Aggregate investment income (line 440 of the T2 return)	0 M1			
Subtotal (**add** lines K1, L1, and M1)	0 ▸	0 N1		
Subtotal (line J1 **minus** line N1) (if negative, enter "0")		0 ▸	0 O1	
Taxable income after specified future tax consequences		0 P1		
Enter the following amounts after specified future tax consequences:				
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	0 Q1			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 R1			
Aggregate investment income (line 440 of the T2 return)	0 S1			
Subtotal (**add** lines Q1, R1, and S1)	0 ▸	0 T1		
Subtotal (line P1 **minus** line T1) (if negative, enter "0")		0 ▸	0 U1	
Subtotal (line O1 **minus** line U1) (if negative, enter "0")			0 V1	
GRIP adjustment for specified future tax consequences to first previous tax year (V1 **multiplied** by 68%)			**500**	0

Second previous tax year

Taxable income before specified future tax consequences from the current tax year.			0 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)	0 K2			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 L2			
Aggregate investment income (line 440 of the T2 return)	0 M2			
Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7**	0			
Subtotal (**add** lines K2, L2, and M2)	0 ▸	0 N2		
Subtotal (line J2 **minus** line N2) (if negative, enter "0")		0 ▸	0 O2	
Taxable income after specified future tax consequences		0 P2		
Enter the following amounts after specified future tax consequences:				
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	0 Q2			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 R2			
Aggregate investment income (line 440 of the T2 return)	0 S2			
Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7**	0			
Subtotal (**add** lines Q2, R2, and S2)	0 ▸	0 T2		
Subtotal (line P2 **minus** line T2) (if negative, enter "0")		0 ▸	0 U2	
Subtotal (line O2 **minus** line U2) (if negative, enter "0")			0 V2	
GRIP adjustment for specified future tax consequences to second previous tax year (V2 multiplied by 68%)			**520**	0

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year

Taxable income before specified future tax consequences from the current tax year.		0 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)	0 K3			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 L3			
Aggregate investment income (line 440 of the T2 return)	0 M3			
Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7**	0			
Subtotal (**add** lines K3, L3, and M3)	0 ▶	0 N3		
Subtotal (line J3 **minus** line N3) (if negative, enter "0")		0 ▶	0 O3	
Taxable income after specified future tax consequences		0 P3		
Enter the following amounts after specified future tax consequences:				
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	0 Q3			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 R3			
Aggregate investment income (line 440 of the T2 return)	0 S3			
Accelerated tax reduction (line 637 of T2 return)* **multiplied** by 100/7	0			
Subtotal (**add** lines Q3, R3, and S3)	0 ▶	0 T3		
Subtotal (line P3 **minus** line T3) (if negative, enter "0")		0 ▶	0 U3	
Subtotal (line O3 **minus** line U3) (if negative, enter "0")			0 V3	
GRIP adjustment for specified future tax consequences to third previous tax year (V3 **multiplied** by 68%) **540**				0
Total GRIP adjustment for specified future tax consequences to previous tax years: (**add** lines 500, 520, and 540) (if negative, enter "0")				0 Y

Enter amount W on line 560 on page 1.

* **Note:** The accelerated tax reduction was available for 2001 to 2004 tax years.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year			0 AA
Eligible dividends paid by the corporation in its last tax year	0 BB		
Excessive eligible dividend designations made by the corporation in its last tax year	0 CC		
Subtotal (line BB **minus** line CC)	0 ▶		0 DD
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year) (line AA **minus** line DD)			0 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 on page 1 for post-amalgamation; or
- line 240 on page 1 for post-wind-up.

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year			0 FF
The corporation's money on hand immediately before the end of its previous/last tax year			0 GG
Unused and unexpired losses at the end of the corporation's previous tax year			
Non-capital losses	0		
Net capital losses	0		
Farm losses:	0		
Restricted farm losses	0		
Limited partnership losses	0		
Subtotal	0	0 HH	
Subtotal (**add** lines FF, GG, and HH)			0 II
All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year		0 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		0 KK	
All the corporation's reserves deducted in its previous/last tax year		0 LL	
The corporation's capital dividend account immediately before the end of its previous/last tax year		0 MM	
The corporation's low rate income pool immediately before the end of its previous/last tax year		0 NN	
Subtotal (**add** lines JJ, KK, LL, MM, and NN)		0	0 OO
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0")			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 on page 1 for a corporation becoming a CCPC;
- line 230 on page 1 for post-amalgamation; or
- line 240 on page 1 for post-wind-up.

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Part 5 – GRIP addition for 2006

Use this part to calculate the GRIP balance for a corporation that was a CCPC, or would have been but for an election under subsection 89(11), throughout its tax year that includes January 1, 2006.

	Tax years ending in				
	2001	**2002**	**2003**	**2004**	**2005**
1. Taxable income for the year*	0	0	0	0	0
2. Income for manufacturing and processing profits deduction* (lesser of amount V and Y in Part 9 of Schedule 27)	0	0	0	0	0
3. Income for manufacturing and processing profits deduction—electrical energy, steam* (amount QQ in Part 13 of Schedule 27)	0	0	0	0	0
4. Taxable resource income* (line 435 of the T2 return)	0	0	0	0	0
5. Income for the credit union deduction* (amount E in Part 3 of Schedule 17)	0	0	0	0	0
6. Income for the small business deduction* (amount on line 400, 405, 410, and 425 of the T2 return, whichever is less)	0	0	0	0	0
7. Aggregate investment income* (line 440 of the T2 return)	0	0	0	0	0
8. Income for the accelerated tax reduction* (line 637 of the T2 return multiplied by 100/7)	0	0	0	0	0
9. Subtotal (**add** rows 2 through 8)	0	0	0	0	0
10. Full rate taxable income before specified future tax consequences (row 1 minus row 9) (if negative, enter "0")	0	0	0	0	0
11. **Multiply** row 10 by 63%	0	0	0	0	0
12. Dividends deductible under subsection 112(1) received from connected corporations, that are reasonably considered, to have been paid out of full rate taxable income in respect of the payer corporation	**941** 0	**942** 0	**943** 0	**944** 0	**945** 0
13. **Subtotal** (**add** row 11 and row 12)	0	0	0	0	0
14. Total taxable dividends paid by the corporation (greater of amounts on line 460 and line 500 on Schedule 3)	0	0	0	0	0
15. GRIP addition (row 13 **minus** row 14)(show negative amounts in brackets)	**951** 0	**952** 0	**953** 0	**954** 0	**955** 0

GRIP addition for 2006 (add lines 951, 952, 953, 954, and 955) 0 QQ

Enter the greater of amount QQ or "0" on line 050 on page 1.

* **Note**: For rows 1 to 8, all income amounts are before considering the specified future tax consequences for that tax year.

Canada Customs and Revenue Agency | Agence des douanes et du revenu du Canada

BALANCE SHEET INFORMATION

Schedule 100

Assets	Code	Current year	Prior year
Cash and deposits	**1000**	1,397,349	1,022,966
Accounts Receivable	1060	1,383,703	1,805,178
Taxes receivable	1066		111,593
Inventories	1120	289,290	255,646
Other current assets	1480	2,993,262	2,918,247
Prepaid expenses	1484	47,701	61,065
Land	1600	219,284	219,284
Buildings	1680	787,877	1,193,645
Accumulated amortization of buildings	1681	(80,346)	(491,500)
Other tangible capital assets	1900	19,376,413	18,362,024
Accumulated amortization of other tangible capital assets	1901	(9,560,372)	(8,946,633)
Due from / investment in Canadian related parties	2241	863,194	363,109
Other deferred items / charges	2424	792,461	666,419
Total assets	**2599**	18,509,816	17,541,043

Liabilities	Code	Current year	Prior year
Bank overdraft	**2600**		
Amounts payable and accrued liabilities	2620	3,302,675	3,293,433
Taxes payable	2680	272,000	
Deposits received	2961	130,000	130,000
Due to related parties	3300	7,000,000	7,000,000
Other long term liabilities	3320	212,617	176,528
General provisions / reserves	3325	257,375	253,375
Total liabilities	**3499**	11,174,667	10,853,336

Equity	Code	Current year	Prior year
Common shares	**3500**	5,293,376	5,293,375
Retained earnings / deficit	**3600**	2,041,773	1,394,332
Total equity	**3620**	7,335,149	6,687,707
Total liabilities and equity	**3640**	18,509,816	17,541,043

Retained earnings	Code	Current year	Prior year
Retained earnings/deficit-start	**3660**	1,394,331	1,641,273
Net income / loss	**3680**	1,047,442	353,059
Dividends declared	3700	(400,000)	(600,000)
Total retained earnings	**3849**	2,041,773	1,394,332

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INCOME STATEMENT INFORMATION

Schedule 125

Details

Operating name, if different from the corporations' legal name
0001

Description of operation, if filing multiple Schedules 125
0002

Revenue	Code	Current year	Prior year
Trade sales of goods and services	8000	24,100,158	24,004,814
Total sales of goods and services	8089	24,100,158	24,004,814
Other revenue	8230	546,608	337,497
Total revenue	8299	24,646,766	24,342,311

Cost of sales	Code	Current year	Prior year
Opening inventory	8300		
Purchases / cost of materials	8320	19,742,669	20,345,694
Cost of sales	8518	19,742,669	20,345,694
Gross profit / loss (item 8089 - item 8518)	8519	4,357,489	3,659,120

Operating expenses	Code	Current year	Prior year
Amortization of tangible assets	8670	838,632	828,412
Interest and bank charges	8710	25,397	76,282
Interest on long term debt	8714	507,500	507,500
Other expenses	9270	440,288	431,120
Delivery, freight and express	9275	694,513	632,802
General and administrative expenses	9284	792,712	879,035
Total operating expenses	9367	3,299,042	3,355,151
Total expenses	9368	23,041,711	23,700,845
Net non-farming income	9369	1,605,055	641,466

Farming revenue	Code	Current year	Prior year
Grains and oilseeds	9370		
Total farm revenue	9659		

Farming expenses	Code	Current year	Prior year
Crop expenses	9660		
Total farm expenses	9898		
Net farm income	9899		
Net income / loss before taxes and extraordinary items	9970	1,605,055	641,466

Summary

Complete this section if only one Schedule 125 is filed, Schedule 140 is used to summarize the information from multiple Schedules 125.

Extraordinary items	9975	-		-	
Legal settlements	9976	-		-	
Unrealized gains / losses	9980	+		+	
Unusual items	9985	-		-	
Current income taxes	9990	-	557,613	-	288,407
Future income tax provision	9995	-		-	
Net income / loss after taxes and extraordinary items	9999	=	1,047,442	=	353,059

Canada Customs and Revenue Agency | Agence des douanes et du revenu du Canada

INCOME STATEMENT INFORMATION

Schedule 125

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Net income / loss after taxes and extraordinary items	9999	=	1,047,442	=	353,059

Canada Revenue Agency / Agence du revenu du Canada

Schedule 141
Code 0801

NOTES CHECKLIST

- 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) for Corporations 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 preparing or reporting on the financial statements

Does the accountant have a professional designation?	095 ☒ Yes	☐ No
Is the accountant connected* with the corporation?	097 ☐ Yes	☒ No

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note
If the accountant does not have a professional designation or is connected with the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4 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 ☒
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 ☐ Yes	☒ No

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 ☒ Yes	☐ No
If **yes**, complete lines 102 to 107 below:		
Are any values presented at other than cost?	102 ☐ Yes	☒ No
Has there been a change in accounting policies since the last return?	103 ☐ Yes	☒ No
Are subsequent events mentioned in the notes?	104 ☐ Yes	☒ No
Is re-evaluation of asset information mentioned in the notes?	105 ☐ Yes	☒ No
Is contingent liability mentioned in the notes?	106 ☐ Yes	☒ No
Is information regarding commitments mentioned in the notes?	107 ☐ Yes	☒ No
Does the corporation have investments in joint venture(s) or partnership(s)?	108 ☐ Yes	☒ No
If **yes**, complete line 109 below:		
Are you filing financial statements of the joint venture(s) or partnership(s)?	109 ☐ Yes	☐ No

Ontario — Ministry of Revenue — Corporations Tax, 33 King Street West, PO Box 620, Oshawa ON L1H 8E9

2007

CT23 Corporations Tax and Annual Return

For taxation years commencing after December 31, 2004

Corporations Tax Act - Ministry of Finance (MOF)
Corporations Information Act - Ministry of Government Services (MGS)

This form is a combination of the Ministry of Revenue (MOR) **CT23 Corporations Tax Return** and the Ministry of Government Services (MGS) **Annual Return**. Page 1 is a common page required for both Returns. For tax purposes, depending on which criteria the corporation satisfies, it must complete either the **Exempt from Filing (EFF)** declaration on page 2 or file the **CT23 Return** on pages 3-17. Corporations that **do not** meet the EFF criteria but do meet the Short-Form criteria, may request and file the **CT23 Short-Form Return** (see page 2).

The **Annual Return** (common page 1 and MGS Schedule A on pages 18 and 19, and Schedule K on page 20) contains non-tax information collected under the authority of the *Corporations Information Act* for the purpose of maintaining a public database of corporate information. This return must be completed by Ontario share-capital corporations or Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* ☒ Yes ☐ No **Page 1 of 20**

Ministry Use

Corporation's Legal Name *(including punctuation)*: Lakefront Utilities Inc.

Ontario Corporations Tax Account No. (MOF): 1800124

Mailing address: 207 Division Street
City: Cobourg | Province: ON | Country: CA | Postal code: K9A 4L3

This Return covers the Taxation Year
Start: 2008/01/01
End: 2008/12/31

Has the mailing address changed since last filed CT23 Return? ☐ Yes | Date of Change: year month day

Date of Incorporation or Amalgamation: 2000/05/01

Registered/Head Office Address: 207 Division Street
City: Cobourg | Province: ON | Country | Postal code: K9A 4L3

Ontario Corporation No. (MGS): 1412420

Location of Books and Records: 207 Division Street
City: Cobourg | Province: ON | Country | Postal code: K9A 4L3

Canada Revenue Agency Business No.: 111111118RC0001

Name of person to contact regarding this CT23 Return: Stewart Cunningham
Telephone No.: (905) 372-2193
Fax No.: ( ) -

Jurisdiction Incorporated: Ontario

Address of Principal Office in Ontario (*Extra-Provincial Corporations only*) (MGS)
City | Province | Country | Postal code

If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased:
Commenced:
Ceased:

Former Corporation Name (*Extra-Provincial Corporations only*) ☐ *Not Applicable* (MGS)

☒ *Not Applicable*

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). ▸

No. of Schedule(s): 0

Preferred Language / *Langue de préférence*: ☒ English *anglais* ☐ French *français*

If there is **no change** to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check ☑ this box. Schedule(s) A and K are not required (MGS). ▸ ☒ No Change

Ministry Use

Certification (MGS)

I certify that all information set out in the **Annual Return** is true, correct and complete.

Name of Authorized Person: Stewart Cunningham

Title: D ☐ Director O ☐ Officer P ☐ Other individuals having knowledge of the Corporation's business activities

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

ProFile - Version 2006.7.0 - Approval code - 080G

1

Taxation Year End

Exempt From Filing (EFF) Corporations Tax Return Declaration

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)

This EFF Declaration must be filed for each taxation year that the corporation is exempt from filing and must be filed within 6 months after the corporation's taxation year end.

Criteria for exempt from filing status:

a) has filed a federal Income Tax Return (T2) with Canada Revenue Agency for the taxation year;
b) had no Ontario taxable income for the taxation year (subject to the provisions in Note 2 below);
c) had no Ontario Corporations Tax payable for the taxation year;
d) was a Canadian-controlled private corporation throughout the taxation year (i.e. generally a private corporation with 50% or more shares owned by Canadian residents as defined by the *Income Tax Act* (Canada));
e) has provided its Canada Revenue Agency business number to the Ministry of Revenue; and
f) is **not** subject to the Corporate Minimum Tax (i.e. alone or as part of an associated group whose total assets exceed $5 million or whose total revenue exceeds $10 million for the taxation year).

Note 1: Filing of this declaration and the Annual Return does not constitute the filing of a Corporations Tax Return under section 75 of the *Corporations Tax Act*.

Note 2: The following loss situations will require otherwise EFF corporations to file a CT23 tax return complete with all related schedules and financial statements:

- If a corporation has a loss in the current taxation year that is to be carried back and applied to a previous taxation year(s), regardless of whether the loss is the same as for federal purposes or not, a CT23 tax return is required for the current taxation year. The corporation must also provide information indicating that the loss is to be carried back and specify the year and the amount of loss to be carried back to each taxation year.
- If a corporation has a prior year loss, that is not the same for both federal and Ontario purposes and the corporation is applying a loss carryforward from the prior year to the current year, a CT23 tax return is required for the current taxation year, and if not previously filed, a CT23 tax return for the prior taxation year in which the loss was incurred is also required. Although a tax return for the loss year is not required where the loss is not being applied, the ministry will accept the filing of a tax return for a loss year at the time the loss is incurred.
- If a corporation has a prior year loss, that is the same for both federal and Ontario purposes, but in the current taxation year the corporation is applying a different amount of loss for Ontario than the loss amount being applied for federal income tax purposes, the corporation is required to file a CT23 tax return for the current taxation year only.

The following 3 items MUST be completed for EFF declarations only. In cases where the Annual Return, which includes page 1, is **also** being filed, completion of these fields is **not** required.

1. Corporation's Mailing Address

City | Province | Country | Postal code

2. Ontario Corporation No. (MGS)

3. Canada Revenue Agency Business No.
RC

I, _____ declare that:

The above corporation meets **all** of the exempt from filing criteria (a) through (f) above for the taxation year and therefore qualifies under the *Corporations Tax Act* as exempt from filing an Ontario Corporations Tax Return.

Signature	Title/Relationship to Corporation	Telephone number	Date
		( ) -	

Please note that making a false statement to avoid compliance with the *Corporations Tax Act* is an offence which can result in a penalty and/or fine.

If you check "Yes" to ALL of the following criteria, you are eligible to file the CT23 Short-Form Corporations Tax Return. To obtain a copy, contact the Ministry Information Centre at the numbers listed on page 2 of the Guide.

Yes	No		
☒	☐	(a)	The corporation is a Canadian-controlled private corporation (CCPC) throughout the taxation year. Indicate Share Capital with full voting rights owned by Canadian Residents (nearest whole percentage) 0 %
☐	☒	(b)	The corporation's taxable income for the taxation year is $200,000 or less. For a taxation year with less than 51 weeks, taxable income must be grossed-up. (*Refer to Guide.*)
☐	☒	(c)	The corporation is **not** a member of a partnership/joint venture or a member of an associated group of corporations during the taxation year.
☐	☒	(d)	The corporation's taxation year ends on or after January 1, 2001, and its gross revenue and total assets are each $1,500,000 or less and the corporation is not a financial institution; or The corporation's taxation year commences after September 30, 2001, and its gross revenue and total assets are each $3,000,000 or less and the corporation is not a financial institution.
☐	☒	(e)	The corporation is not claiming a tax credit other than the Incentive Deduction for Small Business Corporations (IDSBC), Co-operative Education Tax Credit (CETC), Graduate Transitions Tax Credit (GTTC) or Apprenticeship Training Tax Credit (ATTC).
☒	☐	(f)	The corporation's Ontario allocation factor is 100%.

Note: Family Farm or Fishing corporations that have a taxation year ending on or after January 1, 2000 and are **not** subject to the Corporate Minimum Tax, may also use the **CT23 Short-Form Corporations Tax Return** if the corporation checks "Yes" to a), b), c), e) and f) above.

1

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

Please check applicable (✓) **box(es) and complete required information.**

Type of Corporation

1
- 1 [X] Canadian-controlled private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))
- 2 [ ] Other Private
- 3 [ ] Public
- 4 [ ] Non-share Capital
- 5 [ ] Other (*specify*)

Share Capital with full voting rights owned by Canadian Residents (nearest percent) 0 %

2
- 1 [ ] Family Farm corporation s.1(2)
- 2 [ ] Family Fishing corporation s.1(2)
- 3 [ ] Mortgage Investment corporation s.47
- 4 [ ] Credit Union s.51
- 5 [ ] Bank Mortgage subsidiary s.61(4)
- 6 [ ] Bank s.1(2)
- 7 [ ] Loan and Trust corporation s.61(4)
- 8 [ ] Non-resident corporation s.2(2)(a) or (b)
- 9 [ ] Non-resident corporation s.2(2)(c)
- 10 [ ] Mutual Fund corporation s.48
- 11 [ ] Non-resident owned investment corporation s.49
- 12 [ ] Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)
- 14 [ ] Bare Trustee corporation
- 15 [ ] Branch of Non-resident s.63(1)
- 16 [ ] Financial institution prescribed by Regulation only
- 17 [ ] Investment Dealer
- 18 [ ] Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale
- 19 [X] Hydro successor, municipal electrical utility or subsidiary of either
- 20 [ ] Producer and seller of steam for uses other than for the generation of electricity
- 21 [ ] Insurance Exchange s.74.4
- 22 [ ] Farm Feeder Finance Co-operative corporation
- 23 [ ] Professional corporation (incorporated professionals only)

- [ ] This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)
- [ ] Amended Return
- [ ] Taxation year end change - Canada Revenue Agency approval required
- [ ] Final taxation year up to dissolution (*Note: for discontinued businesses, see guide.*)
- [ ] Final taxation year before amalgamation
- [ ] The corporation has a floating fiscal year end
- [ ] There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario
- [ ] There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year
  If checked, date control was acquired _____
- [ ] The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)
- [ ] First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)
- [ ] Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes	No	
[ ]	[X]	Was the corporation inactive throughout the taxation year?
[X]	[ ]	Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?
		Are you requesting a refund due to:
[ ]	[X]	the Carry-back of a Loss?
[X]	[ ]	an Overpayment?
[ ]	[X]	a Specified Refundable Tax Credit?
[ ]	[X]	Are you a Member of a Partnership or Joint Venture?

Complete if applicable

Ontario Retail Sales Tax Vendor Permit no. (Use Head Office no.) _____

Ontario Employer Health Tax Account no. (Use Head Office no.) _____

Specify major business activity
Utility

1

Income Tax

CT23 Page 4 of 20

Allocation – If you carry on a business through a permanent establishment in a jurisdiction outside Ontario, you may allocate that portion of taxable income deemed earned in that jurisdiction to that jurisdiction (s.39) (Int.B. 3008).

Net income (loss) for Ontario purposes (per reconciliation schedule, page 15)	From 690 ±	1,758,516
Subtract: Charitable donations	1 -	
Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property *(Attach schedule 2)*	2 -	
Subtract: Taxable dividends deductible, per federal Schedule 3	3 -	
Subtract: Ontario political contributions *(Attach schedule* 2A) (Int.B. 3002R)	4 -	
Subtract: Federal Part VI.1 tax X 3	5 -	
Subtract: Prior years' losses applied - Non-capital losses	From 704 -	
From 715 inclusion		
Net capital losses (page 16) X rate 50.000000 %	= 714 -	
Farm losses	From 724 -	
Restricted farm losses	From 734 -	
Limited partnership losses	From 754 -	
Taxable income (Non-capital loss)	10 =	1,758,516
Addition to taxable income for unused foreign tax deduction for federal purposes	11 +	
Adjusted taxable income 10 + 11 (if 10 is negative, enter 11)	20 =	1,758,516

Taxable Income

					Number of days in Taxation Year				
					Days after Dec. 31, 2002 and before Jan. 1, 2004	Total Days			
From 10 (or 20)	1,758,516	X30	100.0000 %	X 12.5% X 33		÷ 73	366	= 29 +	
			Ontario Allocation		Days after Dec. 31, 2003	Total Days			
From 10 (or 20)	1,758,516	X30	100.0000 %	X 14.0% X 34	366	÷ 73	366	= 32 +	246,192
			Ontario Allocation						
Income Tax Payable (before deduction of tax credits) 29 + 32								40 =	246,192

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

If this section is not completed, the IDSBC will be denied.

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? (✓) ☒ Yes ☐ No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))		50	1,758,516
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	51 + 1,758,516		
Add: Losses of other years deducted for federal purposes (fed.s.111)	52 +		
Subtract: Losses of other years deducted for Ontario purposes (s.34)	53 -		
	= 1,758,516	54	1,758,516
Federal Business limit (line 410 of the T2 return) for the year before the application of fed.s.125(5.1)	55 + 400,000		

Ontario Business Limit Calculation

	Days after Dec. 31, 2002 and before Jan. 1, 2004					
320,000 X 31		÷ ** 366	=+ 46			
	Days after Dec. 31, 2003					
400,000 X 34	366	÷ ** 366	=+ 47	500,000		

Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated.

Business limit for Ontario purposes 46 ÷ 47	= 44	500,000	X 48	100.0000 % =	45 500,000
Income eligible for the IDSBC	From 30	100.0000 % X	56	500,000	60 = 500,000
		***Ontario Allocation		Least of 50, 54 or 45	

* ***Note:*** *Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)*

** ***Note:*** *Adjust accordingly for a floating taxation year and use 366 for a leap year.*

*** ***Note:*** *Ontario Allocation for IDSBC purposes may differ from 30 if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).*

continued on Page 5

Income Tax *continued from Page 4*

Number of Days in Taxation Year

Calculation of IDSBC Rate	7.0% X **31**	Days after Dec. 31, 2002 and before Jan. 1, 2004	÷ **73**	Total Days 366	= **89**	+			
	8.5% X **34**	Days after Dec. 31, 2003 366	÷ **73**	Total Days 366	= **90**	+	8.5000		
IDSBC Rate for Taxation Year **89 + 90**						= **78**	8.5000		
Claim	From **60**	500,000	X From **78**	8.5000 %		= **70**	42,500		

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount in **114** below.

Surtax on Canadian-controlled Private Corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

Associated corporation - The Taxable Income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

*** Taxable Income of the corporation**	From **10** (or **20** if applicable)	**80** +	1,758,516
If you are a member of an associated group (✓) **81** [X] (Yes)			

Name of associated corporation (Canadian & foreign)	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		* Taxable Income (if loss, enter nil)
Town of Cobourg Holdings Inc.		2008/12/31	+ **82**	
Lakefront Utilities Services Inc.		2008/12/31	+ **83**	
Cobourg Networks Inc.		2008/12/31	+ **84**	

Aggregate Taxable Income **80 + 82 + 83 + 84** , etc. **85** = 1,758,516

Number of days in Taxation Year

320,000 X **31**	Days after Dec. 31, 2002 and before Jan. 1, 2004 ÷	**73**	Total Days 366	= **115** +			
400,000 X **34**	Days after Dec. 31, 2003 366 ÷	**73**	Total Days 366	= **116** +	500,000		
			115 + 116	=	500,000 ▶	**114** -	500,000
(If negative, enter nil)						**86** =	1,258,516

Number of Days in Taxation Year

Calculation of Specified Rate for Surtax	4.667% X **38**	Days after Dec. 31, 2002 366	÷ **73**	Total Days 366	= **97**	+	4.2500		
From **86** 1,258,516	X From **97** 4.2500 %	=				= **87**	53,487		
From **87** 53,487	X From **60** 500,000	+ From **114** 500,000				= **88**	53,487		

Surtax Lesser of **70** or **88** **100** = 42,500

**** Note: Short Taxation Years*** - Special rules apply where the taxation year is less than 51 weeks for the corporation and/or any corporation associated with it.

continued on Page 6

Income Tax *continued from Page 5*

Additional Deduction for Credit Unions (s.51(4)) *(Attach schedule 17)* 110

Manufacturing and Processing Profits Credit (M&P) (s.43)

Applies to Eligible Canadian Profits from manufacturing and processing, farming, mining, logging and fishing carried on in Canada, as determined by regulations.

Eligible Canadian Profits from mining are the "resource profits from the mining operations", as determined for Ontario depletion purposes, after deducting depletion and resource allowances but excluding amounts from sale of Canadian resource property, rentals or royalties. If you are claiming this credit, attach a copy of Ontario schedule 27.

The whole of the active business income qualifies as Eligible Canadian Profits if: a) your active business income from sources other than manufacturing and processing, mining, farming, logging or fishing is 20% or less of the total active business income and b) the total active business income is $250,000 or less.

Eligible Canadian Profits		120 +	
Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC)	From 56	-	500,000
Add: Adjustment for Surtax on Canadian-controlled private corporations From 100 42,500 ÷ From 30 100.0000 % * From 78 8.5000 % = 121 500,000 *Ontario Allocation			
Lesser of 56 or 121		122 +	500,000
120 - 56 + 122		130 =	
Taxable Income	From 10	+	1,758,516
Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC)	From 56	-	500,000
Add: Adjustments for Surtax on Canadian-controlled private corporations	From 122	+	500,000
Subtract: Taxable income 10 X Allocation % to jurisdictions outside Canada		140 -	
Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses		141 -	
10 - 56 + 122 - 140 - 141		142 =	1,758,516

Claim

Number of Days in Taxation Year

143 Lesser of 130 or 142 X From 30 100.0000 % X 1.5% X 33 (Days after Dec. 31, 2002 and before Jan. 1, 2004) + 73 366 (Total Days) = 154 +

143 Lesser of 130 or 142 X From 30 100.0000 % X 2.0% X 34 366 (Days after Dec. 31, 2003) + 73 366 (Total Days) = 156 +

*Ontario Allocation

M&P claim for taxation year 154 + 156 160 =

****Note:*** *Ontario Allocation for M&P Credit purposes may differ from 30 if Taxable Income is allocated to foreign jurisdictions. See special rules (s.43(1))*

Manufacturing and Processing Profits Credit for Electrical Generating Corporations 161 =

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity 162 =

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). *(Attach schedule)* 170

Credit for Investment in Small Business Development Corporations (SBDC)

Applies if you have an unapplied previously approved credit from prior years' investments in new issues of equity shares in Small Business Development Corporations. Any unused portion may be carried forward indefinitely and applied to reduce subsequent years' income taxes. (Refer to the former *Small Business Development Corporations Act*)

Eligible Credit 175 Credit Claimed 180

Subtotal of Income Tax 40 - 70 + 100 - 110 - 160 - 161 - 162 - 170 - 180 190 = 246,192

continued on Page 7

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Income Tax *continued from Page 6*

Specified Tax Credits *(Refer to Guide)*

Ontario Innovation Tax Credit (OITC) (s.43.3) ***Applies*** to scientific research and experimental development in Ontario.
Eligible Credit from **5620** OITC Claim Form *(Attach original Claim Form)* — 191 +

Co-operative Education Tax Credit (CETC) (s.43.4) ***Applies*** to employment of eligible students.
Eligible Credit from **5798** CT23 Schedule 113 *(Attach Schedule 113)* — 192 +

Ontario Film & Television Tax Credit (OFTTC) (s.43.5)
Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. Name of Production 204
Eligible Credit from **5850** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* — 193 +

Graduate Transitions Tax Credit (GTTC) (s.43.6) No. of Graduates From **6596** 194
Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005.
Eligible Credit from **6598** CT23 Schedule 115 *(Attach Schedule 115)* — 195 +

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)
Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.
Eligible Credit from **6900** OBPTC Claim Form
*(Attach **both** the original Claim Form and the Certificate of Eligibility)* — 196 +

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)
Applies to labour relating to computer animation and special effects on an eligible production.
Eligible Credit from **6700** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* — 197 +

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)
Applies to qualifying R&D expenditures under an eligible research institute contract.
Eligible Credit from **7100** OBRITC Claim Form *(Attach original Claim Form)* — 198 +

Ontario Production Services Tax Credit (OPSTC) (s.43.10)
Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.
Eligible Credit from **7300** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* — 199 +

Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)
Applies to qualifying labour expenditures of eligible products for the taxation year.
Eligible Credit from **7400** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* — 200 +

Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)
Applies to qualifying expenditures in respect of eligible Canadian sound recordings.
Eligible Credit from **7500** OSRTC Claim Form
*(Attach **both** the original Claim Form and the Certificate of Eligibility)* — 201 +

Apprenticeship Training Tax Credit (ATTC) (s.43.13) No. of Apprentices From **5896** 202
Applies to employment of eligible apprentices.
Eligible Credit from **5898** CT23 Schedule 114 *(Attach Schedule 114)* — 203 +

Total Specified Tax Credits 191 + 192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 + 203 — 220 =

Specified Tax Credits ***Applied to reduce Income Tax*** — 225 =

Income Tax 190 - 225 OR Enter NIL if reporting Non-Capital Loss *(amount cannot be negative)* — 230 = 246,192

To determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see **Determination of Applicability** section for the CMT on **Page 8**. If CMT is not applicable, transfer amount in **230** to Income Tax in **Summary** section on **Page 17**.

OR

If CMT is not applicable for the current taxation year but your corporation has CMT Credit Carryovers that you want to apply to reduce income tax otherwise payable, then proceed to and complete the **Application of CMT Credit Carryovers** section part B, on **Page 8**.

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Corporate Minimum Tax (CMT)

Total Assets of the corporation	240 +	18,509,816
Total Revenue of the corporation	241 +	24,646,766

The above amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

If you are a member of an associated group (✓) 242 ☒ (Yes)

Name of associated corporation (Canadian & foreign)	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Total Assets	Total Revenue
Town of Cobourg Holdings Inc.		2008/12/31	+ 243	+ 244
Lakefront Utilities Services Inc.		2008/12/31	+ 245	+ 246
Cobourg Networks Inc.		2008/12/31	+ 247	+ 248

Aggregate Total Assets **240 + 243 + 245 + 247**, etc.	249 =	18,509,816
Aggregate Total Revenue **241 + 244 + 246 + 248**, etc.	250 =	24,646,766

Determination of Applicability

Applies if ***either*** Total Assets **249** exceeds $5,000,000 ***or*** Total Revenue **250** exceeds $10,000,000.

Short Taxation Years - Special rules apply for determining total revenue where the taxation year of the corporation or any associated corporation or any fiscal period of any partnership(s) / joint venture(s) of which the corporation or associated corporation is a member, is less than 51 weeks.

Associated Corporation - The total assets or total revenue of associated corporations is the total assets or total revenue for the taxation year ending on or before the date of the claiming corporation's taxation year end.

If CMT is applicable to current taxation year, complete section **Calculation: CMT** below and **Corporate Minimum Tax Schedule 101.**

Calculation: CMT *(Attach Schedule 101.)*

Gross CMT Payable - CMT Base From Schedule 101	2136	1,605,055 X (If negative, enter zero)	From 30	100.0000 % X (Ontario Allocation)	4% 276 =	64,202
Subtract: Foreign Tax Credit for CMT purposes *(Attach schedule)*					277 -	
Subtract: Income Tax					From 190 -	246,192
Net CMT Payable (if negative, enter Nil on page 17.)					280 =	

If **280** is less than zero and you do not have a CMT credit carryover, transfer **230** from **Page 7** to **Income Tax Summary, on Page 17.**

If **280** is less than zero and you have a CMT credit carryover, complete A & B below.

If **280** is greater than or equal to zero, transfer **230** to **Page 17** and transfer **280** to **Page 17, and** to **Part 4 of Schedule 101: Continuity of CMT Credit Carryovers.**

CMT Credit Carryover available From Schedule 101 — From 2333

Application of CMT Credit Carryovers

A.	Income Tax (before deduction of specified credits)			From 190 +	246,192
	Gross CMT Payable	From 276 +	64,202		
	Subtract: Foreign Tax Credit for CMT purposes	From 277 -			
	If 276 - 277 is negative, enter NIL in 290	=	64,202 ▸	290 -	64,202
	Income Tax eligible for CMT Credit			300 =	181,990
B.	Income Tax (after deduction of specified credits)			From 230 +	246,192
	Subtract: CMT credit used to reduce income taxes			310 -	
	Income Tax			320 =	246,192

Transfer to Page 17

If A & B apply, 310 cannot exceed the lesser of 230, 300 and your CMT credit carryover available 2333.

If only B applies, 310 cannot exceed the lesser of 230 and your CMT credit carryover available 2333.

Capital Tax *(Refer to Guide and Int.B. 3011R)*

If your corporation is a Financial Institution (s.58(2)), complete lines **480** *and* **430** *on page 10 then proceed to page 13.*

If your corporation is not a member of an associated group and/or partnership and the Gross Revenue and Total Assets as calculated on page 10 in **480** *and* **430** *are both $3,000,000 or less, your corporation is exempt from Capital Tax for the taxation year, except for a branch of a non-resident corporation. A corporation that meets these criteria should disregard all other Capital Tax items (including the calculation of Taxable Capital). Enter NIL in* **550** *on page 12 and complete the return from that point. All other corporations must compute their Taxable Capital in order to determine their Capital Tax payable.*

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

Any Assets and liabilities of a corporation that are being utilized in a joint venture must be included along with the corporation's other Assets and liabilities when calculating its Taxable Paid-up Capital.

Special rules and rates apply to Non-Resident corporations (s.63, s.64 and s.69(3)).

Paid-up Capital of Non-resident: Paid-up capital employed in Canada of a non-resident subject to tax by virtue of s. 2(2)(a) or 2(2)(b), and whose **business is not carried on solely in Canada** is deemed to be the **greater** of (1) taxable Income in Canada divided by 8 percent or (2) total assets in Canada minus certain indebtedness in accordance with the provisions of s.63(1)(a) (Int.B. 3010).

Paid-up Capital

Paid-up capital stock (Int.B. 3012R and 3015R)	350	+	5,293,376
Retained earnings (if deficit, deduct) (Int.B. 3012R)	351	±	2,041,773
Capital and other surpluses, excluding appraisal surplus (Int.B. 3012R)	352	+	
Loans and advances *(Attach schedule)* (Int.B. 3013R)	353	+	342,617
Bank loans (Int.B. 3013R)	354	+	
Bankers acceptances (Int.B. 3013R)	355	+	
Bonds and debentures payable (Int.B. 3013R)	356	+	
Mortgages payable (Int.B. 3013R)	357	+	
Lien notes payable (Int.B. 3013R)	358	+	7,000,000
Deferred credits (including income tax reserves, and deferred revenue where it would also be included in paid-up capital for the purposes of the large corporations tax) (Int.B. 3013R)	359	+	257,375
Contingent, investment, inventory and similar reserves (Int.B. 3012R)	360	+	
Other reserves not allowed as deductions for income tax purposes *(Attach schedule)* (Int.B. 3012R)	361	+	
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	362	+	
Subtotal	370	=	14,935,141
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012R)	371	-	(1,389,383)
Deductible R&D expenditures and ONTTI costs deferred for income tax if not already deducted for book purposes (Int.B. 3015R)	372	-	
Total Paid-up Capital	380	=	16,324,524
Subtract: Deferred mining exploration and development expenses (s.62(1)(d)) (Int.B. 3015R)	381	-	
Electrical Generating Corporations Only - All amounts with respect to electrical generating assets, except to the extent that they have been deducted by the corporation in computing its income for income tax purposes for the current or any prior taxation year, that are deductible by the corporation under clause 11(10)(a) of the *Corporations Tax Act*, and the assets are used both in generating electricity from a renewable or alternative energy source and are qualifying property as prescribed by regulation	382	-	
Net Paid-up Capital	390	=	16,324,524

Eligible Investments *(Refer to Guide and Int.B. 3015R)*

Attach computations and list of corporation names and investment amounts. Short-term investments (bankers acceptances, commercial paper, etc.) are eligible for the allowance only if issued for a term of and held for 120 days or more prior to the year end of the investor corporation.

Bonds, lien notes and similar obligations, (similar obligations, e.g. stripped interest coupons, applies to taxation years ending after October 30, 1998)	402	+	
Mortgages due from other corporations	403	+	
Shares in other corporations (certain restrictions apply) *(Refer to Guide)*	404	+	
Loans and advances to unrelated corporations	405	+	
Eligible loans and advances to related corporations (certain restrictions apply) *(Refer to Guide)*	406	+	863,194
Share of partnership(s) or joint venture(s) eligible investments *(Attach schedule)*	407	+	
Total Eligible Investments	410	=	863,194

continued on Page 10

Capital Tax *continued from Page 9*

Total Assets (Int.B. 3015R)

Total Assets per balance sheet	420 +	18,509,816
Mortgages or other liabilities deducted from assets	421 +	
Share of partnership(s)/joint venture(s) total assets *(Attach schedule)*	422 +	
Subtract: Investment in partnership(s)/joint venture(s)	423 -	
Total Assets as adjusted	430 =	18,509,816
Amounts in **360** and **361** (if deducted from assets)	440 +	
Subtract: Amounts in **371**, **372** and **381**	441 -	(1,389,383)
Subtract: Appraisal surplus if booked	442 -	
Add or Subtract: Other adjustments (specify on an attached schedule)	443 ±	
Total Assets	450 =	19,899,199

Investment Allowance (410 + 450) X 390	Not to exceed 410	460 =	708,131
Taxable Capital 390 - 460		470 =	15,616,393

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)

Gross Revenue of the corporation	24,646,766		
Corporation's Share of partnership(s)/joint venture(s) Gross Revenue *(Attach schedule)*			
Aggregate of Gross Revenue	24,646,766	480	24,646,766
Total Assets (as adjusted)	From 430		18,509,816

Calculation of Capital Tax for all Corporations except Financial Institutions

Note: *This version (2007) of the CT23 may only be used for a taxation year that commenced after December 31, 2004. Financial Institutions use calculations on page 13.*

Important: If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only Section A below.

OR If the corporation is **not** a member of an associated group and/or partnership, complete Section B below, then review only the Capital Tax calculations in Section C on page 11, selecting and completing the one specific subsection (e.g. C3) that applies to the corporation.

OR If the corporation **is** a member of an associated group and/or partnership, complete Section B below and Section D on page 11, and if applicable, complete Section E or Section F on page 12. Note: if the corporation is a member of a connected partnership, please refer to the CT23 Guide for additional instructions before completing the Capital Tax section.

SECTION A

This section applies only if the corporation is a family farm corporation, a family fishing corporation or a credit union that is not a Financial Institution (Int.B. 3018).

Enter NIL in **550** on page 12 and complete the return from that point.

SECTION B

B1 Calculation of Taxable Capital Deduction (TCD)

		Number of Days in Taxation Year					
		Days after Dec. 31, 2004 and before Jan. 1, 2006		Total Days			
7,500,000	X	**36**	+	**73** 366	= **501** +		
		Days after Dec. 31, 2005 and before Jan. 1, 2007		Total Days			
10,000,000	X	**37**	+	**73** 366	= **502** +		
		Days after Dec. 31, 2006 and before Jan. 1, 2008		Total Days			
12,500,000	X	**38**	+	**73** 366	= **504** +		
		Days after Dec. 31, 2007		Total Days			
15,000,000	X	**39** 366	+	**73** 366	= **505** +	15,000,000	
		Taxable Capital Deduction (TCD)		**501 + 502 + 504 + 505**	**503** =	15,000,000	

B2 This section applies to corporations to calculate the prorated capital tax rate.

Calculation of Capital Tax Rate

		Number of Days in Taxation Year					
		Days before Jan. 1, 2007		Total Days			
0.3 %	X	**556**	+	**73** 366	= **511**		%
		Days after Dec. 31, 2006 and before Jan. 1, 2009		Total Days			
0.225 %	X	**557** 366	+	**73** 366	= **512**	0.2250	%
Capital Tax Rate		**511 + 512**			= **516**	0.2250	%

continued on Page 11

Capital Tax Calculation *continued from Page 10*

SECTION C

This section applies if the corporation is **not** a member of an associated group and/or partnership.

C1. If **430** and **480** on page 10 are both $3,000,000 or less, enter NIL in **550** on page 12 and complete the return from that point.

C2. If Taxable Capital in **470** is **equal to or less than the TCD** in **503**, enter NIL in **550** on page 12 and complete the return from that point.

C3. If Taxable Capital in **470 exceeds the TCD** in **503**, complete the following calculation and transfer the amount from **523** to **543** on page 12, and complete the return from that point.

+ From **470** _____
- From **503** _____
= **471** _____ x From **30** 100.0000 % (Ontario Allocation) x From **516** 0.2250 % (Capital Tax Rate) x **555** _____ / 366 (365 (366 if leap year) *If floating taxation year, refer to Guide.* Days in taxation year) = **523** + _____ *Transfer to **543** on page 12 and complete the return from that point*

SECTION D

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either **509** or **524** and complete this section before you can calculate your Capital Tax calculation under either Section E or Section F.

D1. ☐ **509** (✓ if applicable)

All corporations that you are associated with do **not** have a permanent establishment in Canada.
If Taxable Capital **470** on page 10 is equal to or less than the TCD **503** on page 10, enter NIL in **550** on page 12 and complete the return from that point.
If Taxable Capital **470** on page 10 exceeds the TCD **503** on page 10, proceed to **Section E**, enter the TCD amount in **542** in Section E, and complete Section E and the return from that point.

D2. ☒ **524** (✓ if applicable)

One or more of the corporations that you are associated with **maintains** a permanent establishment in Canada.
You and your associated group may continue to allocate the TCD by completing the Calculation below. Or, the associated group **may file an election** under subsection 69(2.1) of the *Corporations Tax Act*, whereby total assets are used to allocate the TCD among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as **Net Deduction**) of the capital tax effect relating to the TCD to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group.
The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year.
In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

D2. Calculation is on next page

continued on Page 12

Capital Tax Calculation *continued from Page 11*

D2. Calculation Do **not** complete this calculation if ss.69(2.1) election is filed

Taxable Capital from **470** on page 10 — From **470** + 15,616,393

Determine aggregate taxable capital of an associated group (excluding financial institutions and corporations exempt from capital tax) and/or partnership having a permanent establishment in Canada

Names of associated corporations (excluding Financial Institutions and corporations exempt from Capital Tax) having a permanent establishment in Canada	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Taxable Capital
Town of Cobourg Holdings Inc.		2008/12/31 + **531**	
Lakefront Utilities Services Inc.		2008/12/31 + **532**	
Cobourg Networks Inc.		2008/12/31 + **533**	
Aggregate Taxable Capital **470 + 531 + 532 + 533**, etc.			**540** = 15,616,393

If **540** above is equal to or less than the TCD **503** on page 10, the corporation's Capital Tax for the taxation year, is NIL.
Enter NIL in **523** in section E below, as applicable.
If **540** above is greater than the TCD **503** on page 10, the corporation must compute its share of the TCD below in order to calculate its Capital Tax for the taxation year under Section E below.

From **470** 15,616,393 + From **540** 15,616,393 X From **503** 15,000,000 **541** = 15,000,000
*Transfer to **542** in Section E below*

Ss.69(2.1) Election Filed

☐ **591** (✓ if applicable) **Election filed.** *Attach a copy of Schedule 591 with this CT23 Return.* Proceed to **Section F** below.

SECTION E

This section applies if the corporation **is** a member of an associated group and/or partnership whose total **aggregate** Taxable Capital **540** above, exceeds the TCD **503** on page 10.

Complete the following calculation and transfer the amount from **523** to **543**, and complete the return from that point.

+ From **470** 15,616,393
- **542** 15,000,000
= **471** 616,393 x From **30** 100.0000 % (Ontario Allocation) x From **516** 0.2250 % (Capital Tax Rate) x **555** 366 (Days in taxation year *365 (366 if leap year)) = **523** + 1,387 (**Total Capital Tax for the taxation year**)
*Transfer to **543** and complete the return from that point*

SECTION F

This section applies if a corporation is a member of an associated group and the associated group has filed a ss.69(2.1) election

+From **470** X From **30** 100.0000 % (Ontario Allocation) x From **516** 0.2250 % (Capital Tax Rate) = **561** +

- Capital tax deduction from **995** relating to **your corporation's** Capital Tax deduction, on Schedule 591 From **995** -
562 =

Capital Tax **562** X **555** 366 (Days in taxation year *365 (366 if leap year)) = **563** + (**Total Capital tax for the taxation year**)
*Transfer to **543** and complete the return from that point*

** If floating taxation year, refer to Guide.*

Capital Tax before application of specified credits	**543** =	1,387
Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)*	**546** -	
Capital Tax 543 - 546 *(amount cannot be negative)*	**550** =	1,387

Transfer to Page 17

continued on Page 13

Capital Tax *continued from Page 12*

Calculation of Capital Tax for Financial Institutions

1.1 Credit Unions Only

For taxation years commencing **after May 4, 1999** enter NIL in **550** on page 12, and complete the return from that point.

1.2 Other than Credit Unions

*(Retain details of calculations for amounts in boxes **565** and **570**. Do not submit with this tax return.)*

565	x **567** 0.4500 %	x From **30**	% x	Days in taxation year **555**		= **569** +	
Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1	Capital Tax Rate(1) *(Refer to Guide)*		Ontario Allocation	*365 (366 if leap year)			
570	x **571** %	x From **30**	% x	Days in taxation year **555**		= **574** +	
Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount	Capital Tax Rate(2) *(Refer to Guide)*		Ontario Allocation	*365 (366 if leap year)			

Capital Tax for Financial Institutions - other than Credit Unions (before Section 2) 569 + 574 **575** =

** If floating taxation year, refer to Guide.*

2. Small Business Investment Tax Credit

(Retain details of eligible investment calculation and, if claiming an investment in CSBIF, retain the original letter approving the credit issued in accordance with the Community Small Business Investment Fund Act. Do not submit with this tax return.)

Allowable Credit for Eligible Investments **585** -

Financial Institutions: Claiming a tax credit for investment in Community Small Business Investment Fund (CSBIF)? (✓) ☐ Yes

Capital Tax - Financial Institutions 575 - 585 **586** =

*Transfer to **543** on Page 12*

Premium Tax (s.74.2 & 74.3) *(Refer to Guide)*

(1) Uninsured Benefits Arrangements **587** x 2% **588** =
Applies to Ontario-related uninsured benefits arrangements.

(2) Unlicensed Insurance (enter premium tax payable in **588** and attach a detailed schedule of calculations. If subject to tax under (1) above, add both taxes together and enter total tax in **588**.)
Applies to Insurance Brokers and other persons placing insurance for persons resident or property situated in Ontario with unlicensed insurers.

Deduct: Specified Tax Credits applied to reduce premium tax *(Refer to Guide)* **589** -

Premium Tax 588 - 589 **590** =

Transfer to Page 17

1

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

Net Income (loss) for federal income tax purposes, per federal T2 Schedule 1	600 ±	1,758,516	
			Transfer to Page 15

Add:

Federal capital cost allowance	601 +	698,052
Federal cumulative eligible capital deduction	602 +	
Ontario taxable capital gain	603 +	
Federal non-allowable reserves. Balance beginning of year	604 +	244,494
Federal allowable reserves. Balance end of year	605 +	
Ontario non-allowable reserves. Balance end of year	606 +	257,375
Ontario allowable reserves. Balance beginning of year	607 +	
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	608 +	
Federal resource allowance *(Refer to Guide)*	609 +	
Federal depletion allowance	610 +	
Federal foreign exploration and development expenses	611 +	
Crown charges, royalties, rentals, etc. deducted for Federal purposes *(Refer to Guide)*	617 +	
Management fees, rents, royalties and similar payments to non-arms' length non-residents		

Number of Days in Taxation Year

		Days after Dec. 31, 2002 and before Jan. 1, 2004		Total Days		
612	X 5/12.5 X	33	+	73 366	= 633 +	

		Days after Dec. 31, 2003		Total Days		
612	X 5/14.0 X	34 366	+	73 366	= 634 +	

Total add-back amount for Management fees, etc. 633 + 634 =	613 +		
Federal Scientific Research Expenses claimed in year from line 460 of fed. form T661 excluding any negative amount in 473 from Ont. CT23 Schedule 161	615 +		
Add any negative amount in 473 from Ont. CT23 Schedule 161	616 +		
Federal allowable business investment loss	620 +		
Total of other items not allowed by Ontario but allowed federally *(Attach schedule)*	614 +		
Total of Additions 601 to 611 + 617 + 613 + 615 + 616 + 620 + 614	=	1,199,921	640 1,199,921
			Transfer to Page 15

Deduct:

Ontario capital cost allowance (excludes amounts deducted under 675)	650 +	698,052
Ontario cumulative eligible capital deduction	651 +	
Federal taxable capital gain	652 +	
Ontario non-allowable reserves. Balance beginning of year	653 +	244,494
Ontario allowable reserves. Balance end of year	654 +	
Federal non-allowable reserves. Balance end of year	655 +	257,375
Federal allowable reserves. Balance beginning of year	656 +	
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) *(Retain calculations. Do not submit.)*	657 +	
Ontario depletion allowance	658 +	
Ontario resource allowance *(Refer to Guide)*	659 +	
Ontario current cost adjustment *(Attach schedule)*	661 +	
CCA on assets used to generate electricity from natural gas, alternative or renewable resources.	675 +	
Subtotal of deductions for this page 650 to 659 + 661 + 675	681	1,199,921
		Transfer to Page 15

continued on Page 15

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

continued from Page 14

Net income (loss) for federal income tax purposes, per federal Schedule 1	From 600 ±	1,758,516	
Total of Additions on page 14	From 640 =	1,199,921	
Sub Total of deductions on page 14	From 681 =	1,199,921	

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up
(***Applies*** only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

Capital Cost Allowance (Ontario) (CCA) on prescribed qualifying intellectual property deducted in the current taxation year 662 _____

ONTTI Gross-up deduction calculation:

From 662 _____ Gross-up of CCA x 100/ 30 100.0000 (Ontario Allocation) - From 662 _____ 663 = _____

Workplace Child Care Tax Incentive (WCCT)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: 665 _____ x 30% x 100/ 30 From 100.0000 (Ontario Allocation) 666 = _____

Workplace Accessibility Tax Incentive (WATI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: 667 _____ x 100% x 100/ 30 From 100.0000 (Ontario Allocation) 668 = _____

Number of Employees accommodated 669

Ontario School Bus Safety Tax Incentive (OSBSTI)
(***Applies*** to the eligible acquisition of school buses purchased after May 4, 1999 and before January 1, 2006.) *(Refer to Guide)*

Qualifying expenditures: 670 _____ x 30% x 100/ 30 From 100.0000 (Ontario Allocation) 671 = _____

Educational Technology Tax Incentive (ETTI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: 672 _____ x 15% x 100/ 30 From 100.0000 (Ontario Allocation) 673 = _____

Ontario allowable business investment loss	678 +		
Ontario Scientific Research Expenses claimed in year in 477 from Ont. Schedule 161	679 +		
Amount added to income federally for an amount that was negative on federal form T661, line 454 or 455 (if filed after June 30, 2003)	677 +		
Total of other deductions allowed by Ontario *(Attach schedule)*	664 +		
Total of Deductions 681 + 663 + 666 + 668 + 671 + 673 + 678 + 679 + 677 + 664	=	1,199,921	680 1,199,921

Net income (loss) for Ontario Purposes 600 + 640 - 680 **690** = 1,758,516
Transfer to Page 4

Continuity of Losses Carried Forward

	Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year	700 (2)	710 (2)	720 (2)	730	740	750
Add: Current year's losses (7)	701	711	721	731	741	751
Losses from predecessor corporations (3)	702	712	722	732		752
Subtotal	703	713	723	733	743	753
Subtract: Utilized during the year to reduce taxable income	704 (2)	715 (2)(4)	724 (2)	734 (2)(4)	744 (4)	754 (4)
Expired during the year	705		725	735	745	
Carried back to prior years to reduce taxable income (5)	706 (2) To Pg 17	716 (2) To Pg 17	726 (2) To Pg 17	736 (2) To Pg 17	746	
Subtotal	707	717	727	737	747	757
Balance at End of Year	709 (8)	719	729	739	749	759

Analysis of Balance at End of Year by Year of Origin

Year of Origin (oldest year first)	Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800 9th preceding taxation year	817 (9)	860 (9)		850	870
801 8th preceding taxation year 2000/12/31	818 (9)	861 (9)		851	871
802 7th preceding taxation year 2001/12/31	819 (9)	862 (9)		852	872
803 6th preceding taxation year 2002/12/31	820	830	840	853	873
804 5th preceding taxation year 2003/12/31	821	831	841	854	874
805 4th preceding taxation year 2004/12/31	822	832	842	855	875
806 3rd preceding taxation year 2005/12/31	823	833	843	856	876
807 2nd preceding taxation year 2006/12/31	824	834	844	857	877
808 1st preceding taxation year 2007/12/31	825	835	845	858	878
809 Current taxation year 2008/12/31	826	836	846	859	879
Total	829	839	849	869	889

Notes:

(1) Non-capital losses include allowable business investment losses, fed.s.111(8)(b), as made applicable by s.34.

(2) Where acquisition of control of the corporation has occurred, the utilization of losses can be restricted. See fed.s.111(4) through 111(5.5), as made applicable by s.34.

(3) Includes losses on amalgamation (fed.s.87(2.1) and s.87(2.11)) and/or wind-up (fed.s.88(1.1) and 88(1.2)), as made applicable by s.34.

(4) To the extent of applicable gains/income/at-risk amount only.

(5) Generally a three year carry-back applies. See fed.s.111(1) and fed.s.41(2)(b), as made applicable by s.34.

(6) Where a limited partner has limited partnership losses, attach loss calculations for each partnership.

(7) Include amount from **11** if taxable income is adjusted to claim unused foreign tax credit for federal purposes.

(8) Amount in **709** must equal total of **829** + **839**.

(9) Include non-capital losses incurred in taxation years ending after March 22, 2004.

1

Request for Loss Carry-Back (s.80(16))

Applies to corporations requesting a reassessment of the return of one or more previous taxation years under s.80(16) with respect to one or more types of losses carried back.

- If, after applying a loss carry-back to one or more previous years, there is a balance of loss available to carry forward to a future year, it is the corporation's responsibility to claim such a balance for those years following the year of loss within the limitations of fed.s.111, as made applicable by s.34.
- Where control of a corporation has been acquired by a person or group of persons, certain restrictions apply to the carry-forward and carry-back provisions of losses under fed.s.111(4) through 111(5.5), as made applicable by s.34.
- Refunds arising from the loss carry-back adjustment may be applied by the Minister of Finance to amounts owing under **any Act administered by the Ministry of Finance.**
- Any late filing penalty applicable to the return for which the loss is being applied will not be reduced by the loss carry-back.
- The application of a loss carry-back will be available for interest calculation purposes on the day that is the latest of the following:
  1) the first day of the taxation year after the loss year,
  2) the day on which the corporation's return for the loss year is delivered to the Minister, or
  3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
- If a loss is being carried back to a **predecessor corporation**, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses	Non-Capital Losses	Total Capital Losses	Farm Losses	Restricted Farm Losses
Total amount of loss	910	920	930	940
Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income. Predecessor Corporation's Tax Account No. (MOF) / Taxation Year Ending	911	921	931	941
i) 3rd preceding 901 2005/12/31				
ii) 2nd preceding 902 2006/12/31	912	922	932	942
iii) 1st preceding 903 2007/12/31	913	923	933	943
Total loss to be carried back	From 706	From 716	From 726	From 736
Balance of loss available for carry-forward	919	929	939	949

Summary

Income Tax	From 230 or 320	+	246,192
Corporate Minimum Tax	From 280	+	
Capital Tax	From 550	+	1,387
Premium Tax	From 590	+	
Total Tax Payable	950	=	247,579
Subtract: Payments	960	-	307,852
Capital Gains Refund (s.48)	965	-	
Qualifying Environmental Trust Tax Credit *(Refer to Guide)*	985	-	
Specified Tax Credits *(Refer to Guide)*	955	-	
Balance	970	=	(60,273)
If payment due Enclosed *	990		
If overpayment: Refund *(Refer to Guide)*	975	=	60,273
Apply to	980		

(Includes credit interest)

* Make your cheque (drawn on a Canadian financial institution) or a money order in Canadian funds, payable to the **Minister of Finance** and print your Ontario Corporation's Tax Account No. (MOF) on the back of cheque or money order. *(Refer to Guide for other payment methods.)*

Certification

I am an authorized signing officer of the corporation. I certify that this CT23 return, including all schedules and statements filed with or as part of this CT23 return, has been examined by me and is a true, correct and complete return and that the information is in agreement with the books and records of the corporation. I further certify that the financial statements accurately reflect the financial position and operating results of the corporation as required under section 75 of the *Corporations Tax Act*. The method of computing income for this taxation year is consistent with that of the previous year, except as specifically disclosed in a statement attached.

Name
Stewart Cunningham

Title
Treasurer

Full Residence Address
207 Division Street

City
Cobourg

Province	Country	Postal Code
ON		K9A 4L3

Signature

Date
2009/04/30

Note: Section 76 of the *Corporations Tax Act* provides penalties for making false or misleading statements or omissions.

1

Ontario

Ministry of Finance

Corporations Tax
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Ontario Capital Cost Allowance
Schedule 8

ONTARIO CAPITAL COST ALLOWANCE

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Lakefront Utilities Inc.	1800124	2008/12/31

Is the corporation electing under regulation 1101(5q)? 101 1 Yes ☐ 2 No ☒

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year	3 Cost of acquisitions during the the year See note 1 below	4 Net adjustments	5 Proceeds of dispositions during the year	6 Ontario undepreciated capital cost (col 2 + 3 or col 2 - 4 - 5)	7 50% rule See note 2 below	8 Reduced undepreciated capital cost (col 6 - 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (col 8 x 9 or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (col 6 - 12)
1	837,187	7,981			845,168	3,991	841,177	4			33,647	811,521
1	9,621,348				9,621,348		9,621,348	4			384,854	9,236,494
10	236,205	284,467			520,672	142,234	378,438	30			113,531	407,141
10	14,571				14,571		14,571	30			4,371	10,200
12	22,008	47,532			69,540	19,573	49,967	100			49,967	19,573
45	8,127				8,127		8,127	45			3,657	4,470
47	840,061	884,188			1,724,249	442,094	1,282,155	8			102,572	1,621,677
50	6,121	3,924			10,045	1,962	8,083	55			4,446	5,599
8		3,559			3,559	1,780	1,779	20			356	3,203
6		13,017			13,017	6,509	6,508	10			651	12,366
								Totals			698,052	

Enter in box **650** on the CT23

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule. See Regulation 1100(2) and (2.2) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

Ontario

Ministry of Finance
Corporations Tax
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Ontario Continuity of Reserves
Schedule 13

Corporation's Legal Name	Ontario Corporations Tax Account No.	Taxation Year End
Lakefront Utilities Inc.	(MOF) 1800124	2008/12/31

For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes

Part 1 - Capital gains reserves

Description of property	Ontario balance at the beginning of the year	Transfer on amalgamation or wind-up of subsidiary	Ontario balance at the end of the year
Totals	A	B	C

The total capital gains reserve at the beginning of the taxation year **A** plus the total capital gains reserve transfer on amalgamation or wind-up of subsidiary **B**, should be entered on Schedule 6; and the total capital gains reserve at the end of the taxation year **C**, should also be entered on Schedule 6.

Part 2 - Other reserves

Description	Ontario balance at the beginning of the year	Transfer on amalgamation or wind-up of subsidiary	Ontario balance at the end of the year
Reserve for doubtful debts			
Reserve for undelivered goods and services not rendered			
Reserve for prepaid rent			
Reserve for December 31, 1995 income			
Reserve for refundable containers			
Reserve for unpaid amounts			
Other tax reserves			
Totals	D	E	F

The amount from **D** plus the amount from **E** should be entered in **607** of the CT23.

The amount from **F** should be entered in **654** of the CT23.

Part 3 - Continuity of non-deductible reserves

Reserve	Ontario opening balance and transfers	Ontario additions	Ontario deductions	Other adjustments	Ontario closing balance
post-employment benefits	244,494				257,375
Totals	244,494				257,375
	*Enter in box **653** of the CT23*				*Enter in box **606** of the CT23*

1

Ontario Ministry of Finance
Corporations Tax
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Paid-Up Capital: Loans and Advances

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Lakefront Utilities Inc.	1800124	2008/12/31

Loans or Advances Credited or Advanced to Corporation (includes accounts payable to related parties outstanding at the taxation year end for 120 days or more and accounts payable to non-related parties outstanding for 365 days or more at the taxation year end)	
Customer deposits	342,617
Total	342,617

*Transfer to **353** on the CT23*

1

Ontario

Ministry of Revenue

Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Lakefront Utilities Inc.	1800124	2008/12/31

Part 1: Calculation of CMT Base

Banks - Net income/loss as per report accepted by Superintendent of Financial Institutions (SFI) under the Bank Act (Canada), adjusted so consolidation/equity methods are not used.
Life insurance corporations - Net income/loss before Special Additional Tax as determined under s.57.1(2)(c) or (d)

Net income/(loss) (unconsolidated, determined in accordance with GAAP)				2100 ±	1,047,442
Subtract (to the extent reflected in net income/loss):					
Provision for recovery of income taxes / benefit of current income taxes	2101 +				
Provision for deferred income taxes (credits) / benefit of future income taxes	2102 +				
Equity income from corporations	2103 +				
Share of partnership(s)/joint venture(s) income	2104 +				
Dividends received/receivable deductible under fed.s.112	2105 +				
Dividends received/receivable deductible under fed.s.113	2106 +				
Dividends received/receivable deductible under fed.s.83(2)	2107 +				
Dividends received/receivable deductible under fed.s.138(6)	2108 +				
Federal Part VI.1 tax on dividends declared and paid, under fed.s.191.1(1) x 3 =	2109 +				
Subtotal		=		▶ 2110 -	
Add (to extent reflected in net income/loss):					
Provision for current taxes / cost of current income taxes	2111 +	557,613			
Provision for deferred income taxes (debits) / cost of future income taxes	2112 +				
Equity losses from corporations	2113 +				
Share of partnership(s)/joint venture(s) losses	2114 +				
Dividends that have been deducted to arrive at net income per Financial Statements s.57.4(1.1) (excluding dividends under fed.s.137(4.1))	2115 +				
Subtotal		=	557,613	▶ 2116 +	557,613
Add/Subtract:					
Amounts relating to s.57.9 election/regulations for disposals etc. of property, occuring before March 22, 2007, for current/prior years					
** Fed.s.85	2117 +		or 2118 -		
** Fed.s.85.1	2119 +		or 2120 -		
** Fed.s.97	2121 +		or 2122 -		
** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years	2123 +		or 2124 -		
** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/prior years	2125 +		or 2126 -		
** Amounts relating to s.57.10 election/ regulations for replacement re fed.s.13(4), 14(6) and 44 for current/prior years	2127 +		or 2128 -		
Interest allowable under ss. 20(1)(c) or (d) of ITA to the extent not otherwise deducted in determining CMT adjusted net income	2150 -				
Capital gains on eligible donations of publicly-listed securities and ecologically sensitive land made after May 1, 2006 (to the extent reflected in net income/loss)	2155 -				
Subtotal (Additions) = ▶				2129 +	
Subtotal (Subtractions)		=		▶ 2130 -	
** Other adjustments				2131 ±	
Subtotal ± 2100 - 2110 + 2116 + 2129 - 2130 ± 2131				2132 =	1,605,055
** Share of partnership(s)/joint venture(s) **adjusted** net income/loss				2133 ±	
Adjusted net income (loss) (if loss, transfer to **2202** in ***Part 2: Continuity of CMT Losses Carried Forward.***)				2134 =	1,605,055
Deduct: * CMT losses: pre-1994 Loss	From 2210 +				
* CMT losses: other eligible losses	2211 +				
		=		▶ 2135 -	

* CMT losses applied cannot exceed adjusted net income or increase a loss
** *Retain calculations. Do not submit with this tax return.*

CMT Base 2136 = 1,605,055

Transfer to CMT Base on page 8 of the CT23 or Page 6 of the CT8

1

Corporate Minimum Tax (CMT)

Part 2: Continuity of CMT Losses Carried Forward

CMT loss continuity by year

Year of origin	Beginning balance	Transfers on amalgamation	Transfers on wind-up	Adjustments	Current year loss	Applied	Ending balance
							Expired
2000/12/31							
2001/12/31							
2002/12/31							
2003/12/31							
2004/12/31							
2005/12/31							
2006/12/31							
2007/12/31							
2008/12/31							
Totals							

Balance at Beginning of year Notes (1), (2) **2201** +

Add:
- Current year's losses **2202** +
- Losses from predecessor corporations on amalgamation that occurred before March 22, 2007 **Note (3)** **2203** +
- Losses from predecessor corporations on wind-up completed before March 22, 2007 **Note (3)** **2204** +
- Amalgamation (✓) **2205** ☐ Yes Wind-up (✓) **2206** ☐ Yes

Subtotal = ▸ **2207** +

Adjustments (attach schedule) **2208** ±

CMT losses available 2201 + 2207 ± 2208 **2209** =

Subtract:
- Pre-1994 loss utilized during the year to reduce adjusted net income **2210** +
- Other eligible losses utilized during the year to reduce adjusted net income **Note (4)** **2211** +
- Losses expired during the year **2212** +

Subtotal = ▸ **2213** -

Balances at End of Year Note (5) 2209 - 2213 **2214** =

Notes:

(1) Pre-1994 CMT loss (see s.57.1(1)) should be included in the balance at beginning of the year. Attach schedule showing computation of pre-1994 CMT loss.

(2) Where acquisition of control of the corporation has occurred, the utilization of CMT losses can be restricted. (see s.57.5(3) and a 57.5(7))

(3) Include and indicate whether CMT losses are a result of an amalgamation that occurred before March 22, 2007, to which fed.s.87 applies and/or a wind-up completed before March 22, 2007, to which fed.s.88(1) applies (see s.57.5(8) and s.57.5(9)). The continuation of CMT losses no longer applies for amalgamations and wind-ups that occur after March 21, 2007.

(4) CMT losses must be used to the extent of the lesser of the adjusted net income **2134** and CMT losses available **2209**.

(5) Amount in **2214** must equal sum of **2270** + **2290**.

(6) Include the lesser of the total investment losses of a predecessor corporation from an investment in another predecessor corporation that is controlled by the first predecessor corporation, and the total unused CMT losses of the other predecessor corporation.

(7) Include the lesser of the total investment losses of the parent corporation from its investment in the subsidiary corporation, and the total unused CMT losses of the subsidiary corporation.

Part 3: Analysis of CMT Losses Year End Balance by Year of Origin

For a pre-1994 loss, use the date of the last taxation year end before your corporation's first taxation year commencing after 1993.

Year of Origin (oldest year first)	CMT Losses of Corporation	CMT Losses of Predecessor Corporations
2240	**2260**	**2280**
2241 2000/12/31	**2261**	**2281**
2242 2001/12/31	**2262**	**2282**
2243 2002/12/31	**2263**	**2283**
2244 2003/12/31	**2264**	**2284**
2245 2004/12/31	**2265**	**2285**
2246 2005/12/31	**2266**	**2286**
2247 2006/12/31	**2267**	**2287**
2248 2007/12/31	**2268**	**2288**
2249 2008/12/31	**2269**	**2289**
Totals	**2270**	**2290**

The sum of amounts 2270 + 2290 must equal amount in 2214.

1

Corporate Minimum Tax (CMT)

Part 4: Continuity of CMT Credit Carryovers

CMT credit continuity by year

Year of origin	Beginning balance	Transfers on amalgamation or wind-up	Adjustments	Current year credit	Applied	Expired	Ending balance
2001/12/31							
2002/12/31							
2003/12/31							
2004/12/31							
2005/12/31							
2006/12/31							
2007/12/31							
2008/12/31							
Totals							

Balance at Beginning of year Note (1) 2301 +

Add: Current year's CMT Credit (**280** on page 8 of the CT23 or **347** on page 6 of the CT8. If negative, enter NIL) From **280 or 347** +

Gross Special Additional Tax **Note (2) 312** on page 5 of CT8. (Life Insurance corporations only. Others enter NIL.) From **312** +

Subtract Income Tax (**190** on page 6 of the CT23 or page 4 of the CT8) From **190** -

Subtotal (If negative, enter NIL) = ▸ **2305** -

Current year's CMT credit (If negative, enter NIL) **280** or **347** – **2305** = ▸ **2310** +

CMT Credit Carryovers from predecessor corporations **Note (3)** **2325** +

Amalgamation (✓) **2315** ☐ Yes Wind-up (✓) **2320** ☐ Yes

Subtotal 2301 + 2310 + 2325 **2330** +

Adjustments *(Attach schedule)* **2332** ±

CMT Credit Carryover available 2330 ± 2332 **2333** =

Transfer to Page 8 of the CT23 or page 6 of the CT8

Subtract: CMT credit utilized during the year to reduce income tax (**310** on page 8 of the CT23 or **351** on page 6 of the CT8.) + From **310 or 351**

CMT Credit expired during the year **2334** +

Subtotal = ▸ **2335** -

Balance at End of Year Note (4) 2333 - 2335 **2336** =

Notes:

(1) Where acquisition of control of the corporation has occurred, the utilization of CMT credits can be restricted. (see s.43.1(5))
(2) The CMT credit of life insurance corporations can be restricted (see s.43.1(3)(b)).
(3) Include and indicate whether CMT credits are a result of an amalgamation that occurred before March 22, 2007 to which fed.s.87 applies and/or a wind-up completed before March 22, 2007, to which fed.s.88(1) applies. (see s.43.1(4))
(4) Amount in **2336** must equal the sum of **2370** + **2390**.

Part 5: Analysis of CMT Credit Carryovers Year End Balance by Year of Origin

Year of Origin (oldest year first)	CMT Credit Carryovers of Corporation	CMT Credit Carryovers of Predecessor Corporation(s)
2340	2360	2380
2341	2361	2381
2342 2001/12/31	2362	2382
2343 2002/12/31	2363	2383
2344 2003/12/31	2364	2384
2345 2004/12/31	2365	2385
2346 2005/12/31	2366	2386
2347 2006/12/31	2367	2387
2348 2007/12/31	2368	2388
2349 2008/12/31	2369	2389
Totals	2370	2390

The sum of amounts 2370 + 2390 must equal amount in 2336.

1

Ontario

Ministry of Finance
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Authorizing or Cancelling a Representative

Complete this form to:

- **authorize** the release of confidential information about the Corporations Tax, Mining Tax or Electricity Act account(s) to the representative named below.
- **cancel** an existing authorization.

Part 1 Client Information

Legal name: Lakefront Utilities Inc.
Phone number: (905) 372-2193
Mailing address (Apt./Suite/Unit no. Street number and name / PO Box, RR): 207 Division Street
City: Cobourg
Province/Territory: ON
Postal code: K9A 4L3

This authorization applies to the following statute(s) and account number(s).

- [X] Corporations Tax Act 1800124
- [ ] Mining Tax Act
- [ ] Electricity Act

Part 2 Authorize the release of information to a representative

Name of representative (If a firm, name of firm.): Collins Barrow Kawarthas LLP
Phone number: (705) 742-3418
Fax number: (705) 742-9775
Mailing address (Apt./Suite/Unit no. Street number and name / PO Box, RR): 418 Sheridan Street
City: Peterborough
Province/Territory: ON
Postal code: K9H 3J9

If your representative is a firm, and you want a specific person in the firm to represent you, state their name and title.
If you do not identify a specific individual in the firm, you are authorizing the Ministry of Finance to deal with anyone from that firm.

Title:

Part 3 Authorization scope and applicable years

- [X] Representative to **deal fully** on your behalf with the Ministry of Finance.

or

- [ ] Representative to **deal in a limited manner** on your behalf, for matters specified here. (e.g., account inquiry, applications, annual returns, payments, etc.) ▼

- [X] Representative to act for **all years**, including all previous and future years.

or

- [ ] Representative to act for **specific year or years** (describe). ▼

Part 4 Cancel the release of information to a representative

Name of representative (If a firm, name of firm.)
Last:
First:

If your representative is an individual within a firm, state their name and title.
Name of person in firm
Last:
First:
Title:

Part 5 Signature *This form will not be accepted unless it is completed fully, signed and dated.*

I authorize the Ministry of Finance to:

- release confidential information about the tax accounts specified in Part 1 and to deal with the representative named in Part 2 in the manner described in Part 3; and/or
- cancel an existing authorization as described in Part 4.

Name
Last: Cunningham
First: Stewart
Title / Relationship to Corporation: Treasurer
Phone number: (905) 372-2193
Signature
Date: 2009/04/30

1
2

1

2009 LUI TAX RETURN

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200 Code 0901

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Ontario (for tax years ending before 2009), Quebec, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, and paragraphs mentioned on this return refer to the *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre 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 86512 5231 RC 0001

Corporation's name

002 Lakefront Utilities Inc.

Address of head office

Has this address changed since the last time you filed your T2 return? 010 1 Yes [ ] 2 No [X]

(If yes, complete lines 011 to 018)

011 207 Division Street

012

City: 015 Cobourg — Province, territory, or state: 016 ON

Country (other than Canada): 017 — Postal code/Zip code: 018 K9A 4L3

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? 020 1 Yes [ ] 2 No [X]

(If yes, complete lines 021 to 028)

021 c/o

022 207 Division Street

023

City: 025 Cobourg — Province, territory, or state: 026 ON

Country (other than Canada): 027 — Postal code/Zip code: 028 K9A 4L3

Location of books and records

Has the location of books and records changed since the last time you filed your T2 return? 030 1 Yes [ ] 2 No [X]

(If yes, complete lines 031 to 038)

031 207 Division Street

032

City: 035 Cobourg — Province, territory, or state: 036 ON

Country (other than Canada): 037 — Postal code/Zip code: 038 K9A 4L3

040 Type of corporation at the end of the tax year

1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change 043

To which tax year does this return apply?

Tax year start: 060 2009/01/01 — Tax year-end: 061 2009/12/31

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? 063 1 Yes [ ] 2 No [X]

If yes, provide the date control was acquired 065

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1) ? 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? 070 1 Yes [ ] 2 No [X]
Amalgamation? 071 1 Yes [ ] 2 No [X]
If yes, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? 072 1 Yes [ ] 2 No [X]
If yes, complete and attach Schedule 24.

Is this the final tax year before amalgamation? 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada? 080 1 Yes [X] 2 No [ ]

If no, give the country of residence on line 081 and complete and attach Schedule 97. 081

Is the non-resident corporation claiming an exemption under an income tax treaty? 082 1 Yes [ ] 2 No [X]
If yes, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

2

1

Client: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2009/12/31 Printed: 2010/06/18 19:53

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules - Answer the following questions. For each yes response, **attach** to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered Yes to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		—
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	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) is the corporation claiming the refundable portion of Part I tax?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210		10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	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?	255		92 *

*** We do not print this schedule.**

Attachments - Continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265		55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

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
Has the major business activity changed since the last return was filed? (enter yes for first-time filers)	281	1 Yes	2 No X

What is the corporation's major business activity? 282
(Only complete if yes was entered at line 281.)

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale 2 Retail

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Distribution of Electricity	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes	2 No X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes	2 No X
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

If the corporation's major business activity is construction, did you have any sub-contractors during the tax year? 295 1 Yes 2 No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI			300	1,129,302 A
Deduct: Charitable donations from Schedule 2	311			
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction *	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal				B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				1,129,302 C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355	D
Taxable income (amount C **plus** amount D)			360	1,129,302
Income exempt under paragraph 149(1)(t)			370	
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724 on page 8.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	1,129,302	A
Taxable income from line 360 on page 3, **minus** 10/3 of the amount on line 632* on page 7, **minus** 3 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	1,129,302	B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

$400,000 x	Number of days in the tax year before 2009 / Number of days in the tax year	365	=		1
$500,000 x	Number of days in the tax year after 2008 / Number of days in the tax year	365 / 365	=	500,000	2
		Add amounts at lines 1 and 2		500,000	4

Business limit (see notes 1 and 2 below)	410	500,000	C

Notes:
1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 X **415** *** 9,162 / 11,250 D = 407,200 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0")	425	92,800	F

Small business deduction

Amount A, B, C, or F whichever is the least	92,800	X	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365	x 16% =	5
Amount A, B, C, or F whichever is the least	92,800	X	Number of days in the tax year after December 31, 2007 / Number of days in the tax year	365 / 365	x 17% = 15,776	6

Total of amounts 5 and 6 - enter on line 9 of page 7	430	15,776	G

* Calculate the amount of foreign non-business income tax credit deductible at line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and the previous tax years, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

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Client: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2009/12/31 Printed: 2010/06/18 19:53

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3			1,129,302 A
Lesser of amounts V and Y from Part 9 of Schedule 27		B	
Amount QQ from Part 13 of Schedule 27		C	
Amount used to calculate the credit union deduction from Schedule 17		D	
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least	92,800	E	
Aggregate investment income from line 440 of page 6		F	
Total of amounts B to F	92,800	▶	92,800 G
Amount A **minus** amount G (if negative, enter "0")			1,036,502 H

Amount H	1,036,502	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365	x 7% =		I
Amount H	1,036,502	x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year	365	x 8.5% =		J
Amount H	1,036,502	x	Number of days in the tax year after December 31, 2008 and before January 1, 2010 / Number of days in the tax year	365 / 365	x 9% =	93,285	K
Amount H	1,036,502	x	Number of days in the tax year after December 31, 2009 and before January 1, 2011 / Number of days in the tax year	365	x 10% =		L

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L 93,285 M

Enter amount M on line 638 of page 7.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, 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)			N
Lesser of amounts V and Y from Part 9 of Schedule 27		O	
Amount QQ from Part 13 of Schedule 27		P	
Amount used to calculate the credit union deduction from Schedule 17		Q	
Total of amounts O to Q		▶	R
Amount N **minus** amount R (if negative, enter "0")			S

Amount S		x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year		x 7% =	T
Amount S		x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year		x 8.5% =	U
Amount S		x	Number of days in the tax year after December 31, 2008 and before January 1, 2010 / Number of days in the tax year		x 9% =	V
Amount S		x	Number of days in the tax year after December 31, 2009 and before January 1, 2011 / Number of days in the tax year		x 10% =	W

General tax reduction – Total of amounts T to W X

Enter amount X on line 639 of page 7.

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			1,129,302	
Deduct: Amount on line 400, 405, 410, or 425 on page 4, whichever is the least		92,800		
Foreign non-business income tax credit from line 632 of page 7		x 25/9 =		
Foreign business income tax credit from line 636 of page 7		x 3 =		
		92,800	92,800	
			1,036,502 X 26 2/3% =	276,401 D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8)			207,144	
Deduct: Corporate surtax from line 600 of page 7				
Net amount			207,144	207,144 E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least			450	0 F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	460			
Deduct: Dividend refund for the previous tax year	465			G
Add the total of:				
Refundable portion of Part I tax from line 450 above				
Total Part IV tax payable from Schedule 3				
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480			H
Refundable dividend tax on hand at the end of the tax year - Amount G **plus** amount H			485	0

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		X 1/3	I
Refundable dividend tax on hand at the end of the tax year from line 485 above			J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 of page 8)			0

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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 — 429,135 A

Corporate surtax calculation

Base amount from line A above			429,135	1
Deduct:				
10% of taxable income (line 360 or amount Z, whichever applies) from page 3			112,930	2
Investment corporation deduction from line 620 below				3
Federal logging tax credit from line 640 below				4
Federal qualifying environmental trust tax credit from line 648 below				5
For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:				
28% of taxable income from line 360 on page 3		a		
28% of taxed capital gains		b		6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)	207,144	c		
Total of lines 2 to 6			112,930	7
Net amount (line 1 **minus** line 7)			316,205	8

Corporate surtax*

Line 8 316,205 x (Number of days in the tax year before January 1, 2008 / Number of days in the tax year) 365 x 4% = 600 B

*The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31 — 602 — C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6				i
Taxable income from line 360 on page 3	1,129,302			
Deduct:				
Amount on line 400, 405, 410, or 425 of page 4, whichever is the least	92,800			
Net amount	1,036,502	▶	1,036,502	ii

Refundable tax on CCPC's investment income – 6 2/3% of whichever is less: amount i or ii — 604 — D

Subtotal (**add** lines A to D) 429,135 E

Deduct:

Small business deduction from line 430 on page 4		15,776	9
Federal tax abatement	608	112,930	
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 M on page 5	638	93,285	
General tax reduction from amount X 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		
Subtotal		221,991 ▶	221,991 F

Part I tax payable – Line E **minus** line F — 207,144 G

Enter amount G on line 700 of page 8.

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Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	207,144
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		207,144

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 Ontario [for tax years ending before 2009], Quebec, and Alberta)	760	150,923	
Provincial tax on large corporations (New Brunswick* and Nova Scotia)	765		
		150,923	150,923
Total tax payable	770		358,067 A

* The New Brunswick tax on large corporations is eliminated effective January 1, 2009.

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		
Total credits	890		B
Balance (line A **minus** line B)			358,067 I

Refund Code 894 Overpayment

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 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 358,067
Enclosed payment 898

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒ NA ☐

Certification

I, 950 Cunningham (Last name) 951 Stewart (First name) 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 further 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 2010/06/18 (Date) Signature of the authorized signing officer of the corporation 956 (905) 372-2193 (Telephone number)

Is the contact person the same as the authorized signing officer? If *no*, complete the information below. 957 1 Yes ☒ 2 No ☐

958 (Name) 959 ( ) - (Telephone number)

Language of correspondence - Langue de correspondance

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

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Canada Revenue Agency / Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

Schedule 1
Code 0901

- 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			A	751,690
Add:				
Provision for income taxes - current	101	355,241		
Provision for income taxes - deferred	102	(10,000)		
Interest and penalties on taxes	103	2,222		
Amortization of tangible assets	104	893,443		
Reserves from financial statements - balance at the end of the year	126	264,156		
Total of lines 101 to 199	500	1,505,062		1,505,062
Deduct:				
Gain on disposal of assets per financial statements	401	10,178		
Capital cost allowance from Schedule 8	403	859,897		
Reserves from financial statements - balance at the beginning of the year	414	257,375		
Total of lines 401 to 499	510	1,127,450		1,127,450
Net income (loss) for income tax purposes - enter on line 300 on page 3 of the T2 return				1,129,302

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Canada Revenue Agency / Agence du revenu du Canada

Schedule 5
Code 0902

TAX CALCULATION SUPPLEMENTARY - CORPORATIONS

Part 1 - Allocation of taxable income

100 402 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 attributable to jurisdiction	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		1,129,302
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		1,129,302

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking center; 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 computing 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 line 760 of the *T2 Corporation - Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2 on the following pages.

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Part 2 - Provincial and territorial tax payable, tax credits, and rebates

Newfoundland and Labrador

Newfoundland and Labrador tax before credits	200		
Add: Newfoundland and Labrador offshore tax	205		
Gross Newfoundland and Labrador tax			A1
Deduct:			
Newfoundland and Labrador political contribution tax credit	500		
Contribution 891			
Newfoundland and Labrador foreign tax credit (from Schedule 21)	501		
Newfoundland and Labrador manufacturing and processing profits tax credit (from Schedule 300)	503		
Newfoundland and Labrador direct equity tax credit (from Schedule 303)	505		
Newfoundland and Labrador resort property investment tax credit (from Schedule 304)	507		
Newfoundland and Labrador small business tax holiday *	511		
Small business tax holiday certificate number (from Form NLSBTH) 832			
Subtotal			B1
Subtotal (amount A1 **minus** amount B1) (if negative, enter "0")			C1
Add:			
Newfoundland and Labrador capital tax on financial institutions (from Schedule 305)	518		
Total Newfoundland and Labrador tax payable before refundable credits (amount C1 **plus** amount on line 518) (if negative, enter "0")			D1
Deduct:			
Newfoundland and Labrador research and development tax credit (from Schedule 301)	520		
Newfoundland and Labrador film and video industry tax credit	521		
Certificate number 821			
Subtotal			E1
Net Newfoundland and Labrador tax payable or refundable credit (amount D1 **minus** amount E1) (if a credit, enter amount in brackets) Include this amount on line 255.		209	F1

* The amount of Newfoundland and Labrador small business tax holiday cannot be more than the gross Newfoundland and Labrador tax **minus** all other Newfoundland and Labrador tax credits (including the refundable credits).

Prince Edward Island

Prince Edward Island tax before credits		210	A2
Deduct:			
Prince Edward Island political contribution tax credit	525		
Contribution 892			
Prince Edward Island foreign tax credit (from Schedule 21)	528		
Prince Edward Island corporate investment tax credit (from Schedule 321)	530		
Subtotal			B2
Net Prince Edward Island tax payable (amount A2 **minus** amount B2) (if negative, enter "0") Include this amount on line 255.		214	C2

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Part 2 - Provincial and territorial tax payable, tax credits, and rebates (continued)

Nova Scotia

Nova Scotia tax before credits (from Schedule 346)		215		
Add:				
Nova Scotia offshore tax (from Schedule 346)		220		
Recapture of Nova Scotia research and development tax credit (from Schedule 340)		221		
Gross Nova Scotia tax				A3
Deduct:				
Nova Scotia political contribution tax credit		550		
Contribution	893			
Nova Scotia foreign tax credit (from Schedule 21)		554		
Nova Scotia manufacturing and processing investment tax credit (from Schedule 344)		561		
Nova Scotia corporate tax reduction for new small businesses * (from Schedule 341)		556		
Certificate number	834			
Manufacturing and processing investment tax credit (10%)				
Subtotal				B3
Total Nova Scotia tax payable before refundable credits (amount A3 **minus** amount B3) (if negative, enter "0")				C3
Deduct:				
Nova Scotia film industry tax credit		565		
Certificate number	836			
Nova Scotia research and development tax credit (from Schedule 340)		566		
Nova Scotia digital media tax credit		567		
Certificate number	838			
Subtotal				D3
Net Nova Scotia tax payable or refundable credit (amount C3 **minus** amount D3)			224	E3
(if a credit, enter amount in brackets) Include this amount on line 255.				

* The amount of Nova Scotia corporate tax reduction for new small businesses cannot be more than the gross Nova Scotia tax **minus** all other Nova Scotia tax credits (including the refundable credits).

New Brunswick

New Brunswick tax before credits (from Schedule 366)		225		
Add:				
Recapture of New Brunswick research and development tax credit (from Schedule 360)		573		
Gross New Brunswick tax				A4
Deduct:				
New Brunswick political contribution tax credit		575		
Contribution	894			
New Brunswick foreign tax credit (from Schedule 21)		576		
New Brunswick non-refundable research and development tax credit (from Schedule 360)		577		
Subtotal				B4
Total New Brunswick tax payable before refundable credits (amount A4 **minus** amount B4) (if negative, enter "0")				C4
Deduct:				
New Brunswick film tax credit		595		
Certificate number	850			
New Brunswick refundable research and development tax credit (from Schedule 360)		597		
Subtotal				D4
Net New Brunswick tax payable or refundable credit (amount C4 **minus** amount D4)			229	E4
(if a credit, enter amount in brackets) Include this amount on line 255.				

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Part 2 - Provincial and territorial tax payable, tax credits, and rebates (continued)

Ontario
(2009 and later tax years only)

Ontario basic income tax (from Schedule 500)	270	158,102		
Deduct: Ontario small business deduction (from Schedule 500)	402	42,500		
Subtotal (if negative, enter "0")		115,602	115,602	A6
Add:				
Surtax re Ontario small business deduction (from Schedule 500)	272	30,565		
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		30,565	30,565	B6
Subtotal (amount A6 **plus** amount B6)			146,167	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 contribution tax credit (from Schedule 525)	415			
Subtotal				D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")			146,167	E6
Ontario research and development tax credit (from Schedule 508)	416			
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")			146,167	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")			146,167	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	4,756		
Subtotal		4,756	4,756	H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)			150,923	I6
Deduct:				
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452			
Ontario apprenticeship training tax credit (from Schedule 552)	454			
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			
Subtotal				J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter amount in brackets) Include this amount on line 255.	290		150,923	K6

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Part 2 - Provincial and territorial tax payable, tax credits, and rebates (continued)

Manitoba

Manitoba tax before credits (from Schedule 383)		230	A7
Deduct:			
Manitoba foreign tax credit (from Schedule 21)	601		
Manitoba manufacturing investment tax credit (from Schedule 381)	605		
Manitoba research and development tax credit (from Schedule 380)	606		
Manitoba co-op education and apprenticeship tax credit (from Schedule 384)	603		
Manitoba odour-control tax credit (from Schedule 385)	607		
Manitoba community enterprise investment tax credit (from Schedule 387)	608		
Subtotal			B7
Total Manitoba tax payable before refundable credits (amount A7 **minus** amount B7) (if negative, enter "0")			C7
Deduct:			
Manitoba refundable research and development tax credit (from Schedule 380)	613		
Manitoba interactive digital media tax credit	614		
Manitoba book publishing tax credit (from Schedule 389)	615		
Manitoba green energy equipment tax credit (manufacturer)	618		
Manitoba green energy equipment tax credit (purchaser)	619		
Manitoba film and video production tax credit *	620		
Certificate number 856			
Manitoba refundable manufacturing investment tax credit (from Schedule 381)	621		
Manitoba refundable co-op education and apprenticeship tax credit (from Schedule 384)	622		
Manitoba refundable odour-control tax credit for agricultural corporations (from Schedule 385)	623		
Subtotal			D7
Net Manitoba tax payable or refundable credit (amount C7 **minus** amount D7) (if a credit, enter amount in brackets) Include this amount on line 255.		234	E7

* If you received a certificate from the Manitoba Department of Finance it should be claimed on line 620. If you have more than one certificate, use Schedule 382. If the certificate was issued by Manitoba Film and Sound Recording Development Corporation, complete Schedule 388, *Manitoba Film and Video Production Tax Credit*, to calculate the amount of the credit and enter your claim on line 620.

Saskatchewan

Saskatchewan tax before credits (from Schedule 411)		235	A8
Deduct:			
Saskatchewan political contribution tax credit	624		
Contribution 890			
Saskatchewan foreign tax credit (from Schedule 21)	625		
Saskatchewan manufacturing and processing profits tax reduction (from Schedule 404)	626		
Saskatchewan manufacturing and processing investment tax credit (from Schedule 402)	630		
Saskatchewan research and development tax credit (from Schedule 403)	631		
Saskatchewan royalty tax rebate (from Schedule 400)	632		
Subtotal			B8
Total Saskatchewan tax payable before refundable credits (amount A8 **minus** amount B8) (if negative, enter "0")			C8
Deduct:			
Saskatchewan qualifying environmental trust tax credit	641		
Saskatchewan film employment tax credit	643		
Certificate number 860			
Saskatchewan refundable manufacturing and processing investment tax credit (from Schedule 402)	644		
Saskatchewan refundable research and development tax credit (from Schedule 403)	645		
Subtotal			D8
Net Saskatchewan tax payable or refundable credit (amount C8 **minus** amount D8) (if a credit, enter amount in brackets) Include this amount on line 255.		239	E8

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Part 2 - Provincial and territorial tax payable, tax credits, and rebates (continued)

British Columbia

British Columbia tax before credits (from Schedule 427)	240		
Add:			
Recapture of British Columbia scientific research and experimental development (SR&ED) tax credit (from Form T666)	241		
Gross British Columbia tax			A10
Deduct:			
British Columbia foreign tax credit (from Schedule 21)	650		
British Columbia logging tax credit	651		
British Columbia political contribution tax credit	653		
Contribution	896		
British Columbia small business venture capital tax credit	656		
Credit at the end of previous tax year	880		
Current-year credit	881		
Certificate number (from SBVC 10)	882		
British Columbia manufacturing and processing tax credit (from Schedule 426)	660		
British Columbia SR&ED non-refundable tax credit (from Form T666)	659		
Subtotal			B10
Total British Columbia tax payable before refundable credits (amount A10 **minus** amount B10) (if negative, enter "0")			C10
Deduct:			
British Columbia qualifying environmental trust tax credit	670		
British Columbia film and television tax credit (from Form T1196)	671		
British Columbia production services tax credit (from Form T1197)	672		
British Columbia mining exploration tax credit (from Schedule 421)	673		
British Columbia SR&ED refundable tax credit (from Form T666)	674		
British Columbia book publishing tax credit (amount on line 886 multiplied by 90%)	665		
Book Publishing Industry Development Program contribution received in the tax year	886		
British Columbia training tax credit (from Schedule 428)	679		
BC Interactive digital media tax credit for video game development			
Subtotal			D10
Net British Columbia tax payable or refundable credit (amount C10 **minus** amount D10) (if a credit, enter amount in brackets) Include this amount on line 255.	244		E10

Yukon

Yukon tax before credits (from Schedule 443)	245		A11
Deduct:			
Yukon political contribution tax credit	675		
Contribution	897		
Yukon foreign tax credit (from Schedule 21)	676		
Yukon manufacturing and processing profits tax credit (from Schedule 440)	677		
Subtotal			B11
Total Yukon tax payable before refundable credits (amount A11 **minus** amount B11) (if negative, enter "0")			C11
Deduct:			
Yukon mineral exploration tax credit (from Schedule 441)	697		
Yukon research and development tax credit (from Schedule 442)	698		
Subtotal			D11
Net Yukon tax payable or refundable credit (amount C11 **minus** amount D11) (if a credit, enter amount in brackets) Include this amount on line 255.	249		E11

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Part 2 - Provincial and territorial tax payable, tax credits, and rebates (continued)

Northwest Territories

Northwest Territories tax before credits			250	A12
Deduct:				
Northwest Territories political contribution tax credit		700		
Contribution	898			
Northwest Territories foreign tax credit (from Schedule 21)		701		
Northwest Territories investment tax credit (from Schedule 460)		705		
Subtotal				B12
Net Northwest Territories tax payable (amount A12 **minus** amount B12) (if negative, enter "0")			254	C12

Include this amount on line 255.

Nunavut

Nunavut tax before credits			260	A13
Deduct:				
Nunavut political contribution tax credit		725		
Contribution	899			
Nunavut foreign tax credit (from Schedule 21)		730		
Northwest Territories investment tax credit on investments made before April 1, 1999 (from Schedule 460)		734		
Nunavut investment tax credit (from Schedule 480)		735		
Subtotal				B13
Total Nunavut tax payable before refundable credits (amount A13 **minus** amount B13) (if negative, enter "0")				C13
Deduct:				
Nunavut business training tax credit (from Schedule 490)			740	D13
Net Nunavut tax payable (amount C13 **minus** amount D13)			264	E13

(if a credit, enter amount in brackets) 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	150,923

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 on page 8 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 on page 8 of the T2 return.

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Canada Revenue Agency / Agence du revenu du Canada

CAPITAL COST ALLOWANCE

Schedule 8

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 200	2 UCC at start of year 201	3 Cost of additions in the year 203	4 Net adjustments 205	5 Proceeds of dispositions in the year 207	7 Adjustment for additions (1/2 x (col 3 - 5)) 211	8 Base amount for CCA	9 Rate % 212	10 Recapture of CCA 213	11 Terminal loss 215	12 CCA for the year (col 8 x 9 or a lower amount) 217	13 UCC at the end of the year 220
1	811,521	74,242			37,121	848,642	4			33,946	851,817
1	8,545,258					8,545,258	4			341,810	8,203,448
10	407,141	54,788		10,178	22,305	429,446	30			128,834	322,917
10	10,200					10,200	30			3,060	7,140
12	19,573	73,749				93,322	100			93,322	
45	4,470					4,470	45			2,012	2,458
47	2,231,617	1,469,274			734,637	2,966,254	8			237,300	3,463,591
50	5,599					5,599	55			3,079	2,520
8	3,203	41,318			20,659	23,862	20			4,772	39,749
6	12,366					12,366	10			1,237	11,129
52		10,525				10,525	100			10,525	
							NA				
Totals	12,050,948	1,723,896		10,178	814,722	12,949,944				859,897	12,904,769

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T2 SCH 8 (99) Version 2009.5.0 GP39 - **RETAIN ON FILE. DO NOT SUBMIT TO THE CRA.**

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Canada Customs and Revenue Agency | Agence des douanes et du revenu du Canada

RELATED AND ASSOCIATED CORPORATIONS

Schedule 9

This form is to be completed by a corporation having one or more of the following:

- related corporation(s)
- associated corporation(s)

Name 100	Country (if not Canada) 200	Business # (Canadian corporation only) 300	Code note 1 400	Common shares # owned 500	Common shares % owned 550	Preferred shares # owned 600	Preferred shares % owned 650	Book value of capital stock 700
Town of Cobourg Holdings Inc		86511 7832 RC 0001	1					
Lakefront Utilities Services Inc		86906 0327 RC 0001	3					
Lakefront Generation Inc.		82428 6942 RC 0001	3					
Lakefront Lighting Inc.		85700 1424 RC 0001	3					
Cobourg Networks Inc		86512 5033 RC 0001	3					

Note 1 : Enter the code number of the relationship that applies: 1- Parent 2 - Subsidiary 3 - Associated 4 - Related, but not associated

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Schedule 23
Code 0901

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, including 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**

Enter the calendar year to which the agreement applies **050** 2009

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 Association code **300**
1	Lakefront Utilities Inc.	86512 5231 RC 0001	1
2	Town of Cobourg Holdings Inc	86511 7832 RC 0001	1
3	Lakefront Utilities Services Inc	86906 0327 RC 0001	3
4	Lakefront Generation Inc.	82428 6942 RC 0001	1
5	Lakefront Lighting Inc.	85700 1424 RC 0001	1
6	Cobourg Networks Inc	86512 5033 RC 0001	1

Allocate business limit using: ☒ % ☐ $

	Taxation year Start	Taxation year End	4 Business limit for the year (before the allocation) $	Allocating business limit: 5 Percentage of the business limit (%) **350**	6 Business limit allocated * $ **400**	7 Gross Part I.3 tax for business limit reduction
1	2009/01/01	2009/12/31	500,000	100.000	500,000	9,162
2	2009/01/01	2009/12/31	500,000			
3	2009/01/01	2009/12/31	500,000			
4	2009/01/01	2009/12/31	500,000			
5	2009/01/01	2009/12/31	500,000			
6	2009/01/01	2009/12/31	500,000			
TOTALS				100.000	A 500,000	9,162

If the taxation year of the corporation filing this form is less than 51 weeks, enter the prorated business limit in this box. $ 500,000

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AGREEMENT AMONG ASSOCIATED CCPCs TO ALLOCATE THE BUSINESS LIMIT

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.

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SCHEDULE 33
Code 1001

TAXABLE CAPITAL EMPLOYED IN CANADA – LARGE CORPORATIONS

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act and the Income Tax Regulations*.
- Subsection 181(1) defines the terms "financial institution," "long-term debt," and "reserves."
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If you are filing a provincial capital tax return with your *T2 Corporation Income Tax Return*, also file a completed Schedule 33 with the return no later than six months from the end of the tax year.
- This schedule may contain changes that had not yet become law at the time of publishing.

If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, "Taxable capital employed in Canada."

Part 1 - Capital

Add the following amounts at the end of the year:

Reserves that have not been deducted in computing income for the year under Part I	101			
Capital stock (or members' contributions if incorporated without share capital)	103	5,293,376		
Retained earnings	104	2,738,463		
Contributed surplus	105			
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108	8,653,000		
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109			
Any dividends declared but not paid by the corporation before the end of the year	110			
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111	429,156		
Proportion of the amount, if any, by which the total of all amounts (see note below) for the partnership of which the corporation is a member at the end of the year exceeds the amount of the partnership's deferred unrealized foreign exchange losses	112			
Subtotal		17,113,995	17,113,995	A

Deduct the following amounts:

Deferred tax debit balance at the end of the year	121			
Any deficit deducted in computing its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122			
Any amount deducted under subsection 135(1) in computing income under Part I for the year, as long as the amount may reasonably be regarded as being included in any of lines 101 to 112 above	123			
The amount of deferred unrealized foreign exchange losses at the end of the year	124			
Subtotal				B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")			190 17,113,995	

Note: Lines 101, 107, 108, 109, 111, and 112 are determined as follows:
- If the partnership is a member of another partnership (tiered partnerships), include the amounts of the partnership and tiered partnerships.
- Amounts for the partnership and tiered partnerships are those that would be determined for lines 101, 107, 108, 109, 111, and 112 as if they apply in the same way that they apply to corporations.
- Do not include amounts owing to the member or to other corporations that are members of the partnership.
- Amounts are determined at the end of the last fiscal period of the partnership ending in the year of the corporation.
- The proportion of the total amounts is determined by the corporation's share of the partnership's income or loss for the fiscal period of the partnership.

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Part 2 - Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend receivable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim, or similar obligation of, a partnership all of the members of which, throughout the year, were other corporations (other than financial institutions) that were not exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)]	406	
An interest in a partnership	407	
Investment allowance for the year (add lines 401 to 407)	490	

Notes:

1. Where the corporation has an interest in a partnership or in tiered partnerships, consider the following:
   - the investment allowance of a partnership is deemed to be the amount calculated at line 490 above, at the end of its fiscal period, as if it was a corporation;
   - the total of the carrying value of each asset of the partnership described in the above lines is for its last fiscal period ending at or before the end of the corporation's tax year; and
   - the carrying value of a partnership member's interest at the end of the year is its specified proportion [as defined in subsection 248(1)] of the partnership's investment allowance.
2. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)].
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation, according to subsection 181.2(6).

Part 3 - Taxable capital

Capital for the year (line 190)		17,113,995	C
Deduct: Investment allowance for the year (line 490)			D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	17,113,995	

Part 4 - Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 17,113,995 x (Taxable income earned in Canada / Taxable income) 610 1,129,302 / 1,129,302 = 690 **Taxable capital employed in Canada** 17,113,995

Notes:

1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada	701		
Deduct the following amounts:			
Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada	711		
Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada	712		
Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below)	713		
Total deductions (add lines 711, 712, and 713)			E
Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0")	790		

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 - Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (line 690 or 790, whichever applies)	17,113,995	F
Deduct:	10,000,000	G
Excess (amount F **minus** amount G) (if negative, enter "0")	7,113,995	H
Calculation for purposes of the small business deduction (amount H x 0.00225)	16,006	I

Enter this amount at line 415 of the T2 return.

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SHAREHOLDER INFORMATION

Schedule 50

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

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 (If a trust number is not available, enter "NA") * 350	Percentage common shares 400	Percentage preferred shares 500
Town of Cobourg Holdings Inc.	NR			100.000	
	RC				

* For a taxation year commencing before January 1, 2004, if the shareholder is a trust, enter NR at field 200 or NA at field 300. Do not enter a trust number in field 350.

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SCHEDULE 53
Code 0901

GENERAL RATE INCOME POOL (GRIP) CALCULATION

- 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.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year				100	1,966,938 A
Taxable income for the year (DICs enter "0")*			110	1,129,302 B	
Income for the credit union deduction* (amount E in Part 3 of Schedule 17)	120	0			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less*	130	92,800			
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income *	140	0			
Subtotal (**add** lines 120, 130 and 140)		92,800		92,800 C	
Income taxable at the general corporate rate (line B **minus** line C)			150	1,036,502	
After-tax income (line 150 x general rate factor for the tax year ** 0.6800)				190	704,821 D
Eligible dividends received in the tax year			200	0	
Dividends deductible under section 113 received in the tax year			210	0	
Subtotal (**add** lines 200 and 210)				0	0 E
GRIP addition:					
Becoming a CCPC (line PP from Part 4)			220	0	
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)			230	0	
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)			240	0	
Subtotal (**add** lines 220, 230, and 240)				0	290 0 F
Subtotal (**add** lines A, D, E, and F)					2,671,759 G
Eligible dividends paid in the previous tax year			300	0	
Excessive eligible dividend designations made in the previous tax year			310	0	
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310. Subtotal (line 300 **minus** line 310)				0	0 H
GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative)				490	2,671,759
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)				560	0
GRIP at the end of the tax year (line 490 minus line 560)				590	2,671,759

Enter this amount on line 160 on Schedule 55.

* 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 the total of 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 on page 5 for tax years that straddle these dates.

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GENERAL RATE INCOME POOL (GRIP) CALCULATION

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560 of page 1.

First previous tax year

Taxable income before specified future tax consequences from the current tax year		0 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)	0 K1			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 L1			
Aggregate investment income (line 440 of the T2 return)	0 M1			
Subtotal (**add** lines K1, L1, and M1)	0 ▶	0 N1		
Subtotal (line J1 **minus** line N1) (if negative, enter "0")		0 ▶	0 O1	
Taxable income after specified future tax consequences		0 P1		
Enter the following amounts after specified future tax consequences:				
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	0 Q1			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 R1			
Aggregate investment income (line 440 of the T2 return)	0 S1			
Subtotal (**add** lines Q1, R1, and S1)	0 ▶	0 T1		
Subtotal (line P1 **minus** line T1) (if negative, enter "0")		0 ▶	0 U1	
Subtotal (line O1 **minus** line U1) (if negative, enter "0")			0 V1	
GRIP adjustment for specified future tax consequences to first previous tax year (line V1 **multiplied** by the general rate factor for the tax year 0.6800)			500	0

Second previous tax year

Taxable income before specified future tax consequences from the current tax year		0 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)	0 K2			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 L2			
Aggregate investment income (line 440 of the T2 return)	0 M2			
Subtotal (**add** lines K2, L2, and M2)	0 ▶	0 N2		
Subtotal (line J2 **minus** line N2) (if negative, enter "0")		0 ▶	0 O2	
Taxable income after specified future tax consequences		0 P2		
Enter the following amounts after specified future tax consequences:				
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	0 Q2			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 R2			
Aggregate investment income (line 440 of the T2 return)	0 S2			
Subtotal (**add** lines Q2, R2, and S2)	0 ▶	0 T2		
Subtotal (line P2 **minus** line T2) (if negative, enter "0")		0 ▶	0 U2	
Subtotal (line O2 **minus** line U2) (if negative, enter "0")			0 V2	
GRIP adjustment for specified future tax consequences to second previous tax year (line V2 **multiplied** by the general rate factor for the tax year 0.6800)			520	0

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GENERAL RATE INCOME POOL (GRIP) CALCULATION

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year		0 FF
The corporation's money on hand immediately before the end of its previous/last tax year		0 GG
Unused and unexpired losses at the end of the corporation's previous tax year		
Non-capital losses	0	
Net capital losses	0	
Farm losses	0	
Restricted farm losses	0	
Limited partnership losses	0	
Subtotal	0	0 HH
Subtotal (**add** lines FF, GG, and HH)		0 II
All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year	0 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	0 KK	
All the corporation's reserves deducted in its previous/last tax year	0 LL	
The corporation's capital dividend account immediately before the end of its previous/last tax year	0 MM	
The corporation's low rate income pool immediately before the end of its previous/last tax year	0 NN	
Subtotal (**add** lines JJ, KK, LL, MM, and NN)	0	0 OO
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0")		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 on page 1 for a corporation becoming a CCPC;
- line 230 on page 1 for post-amalgamation; or
- line 240 on page 1 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. Calculate your results to 4 decimal places.

0.68 x	number of days in the tax year before January 1, 2010 / number of days in the tax year	365 / 365 =	0.6800	QQ
0.69 x	number of days in the tax year in 2010 / number of days in the tax year	0 / 365 =	0.0000	RR
0.70 x	number of days in the tax year in 2011 / number of days in the tax year	0 / 365 =	0.0000	SS
0.72 x	number of days in the tax year after December 31, 2011 / number of days in the tax year	0 / 365 =	0.0000	TT

General Rate Factor for the tax year (total of lines QQ to TT) 0.6800 UU

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BALANCE SHEET INFORMATION

Schedule 100

Assets	Code	Current year	Prior year
Cash and deposits	1000	2,141,428	1,397,349
Accounts Receivable	1060	1,586,245	1,383,703
Taxes receivable	1066	222,900	
Inventories	1120	238,012	289,290
Other current assets	1480	2,817,654	2,993,262
Future income taxes	1481	555,000	
Prepaid expenses	1484	46,588	47,701
Land	1600	219,284	219,284
Buildings	1680	862,119	787,877
Accumulated amortization of buildings	1681	(98,905)	(80,346)
Other tangible capital assets	1900	16,675,049	19,376,413
Accumulated amortization of other tangible capital assets	1901	(6,804,238)	(9,560,372)
Due from / investment in Canadian related parties	2241		863,194
Other deferred items / charges	2424	2,190,895	792,461
Total assets	2599	20,652,031	18,509,816

Liabilities	Code	Current year	Prior year
Bank overdraft	2600		
Amounts payable and accrued liabilities	2620	3,328,973	3,302,675
Taxes payable	2680		272,000
Deposits received	2961	165,000	130,000
Long term debt	3140	1,653,000	
Lien notes	3152		7,000,000
Due to related parties	3300	7,000,000	
Other long term liabilities	3320	209,063	212,617
General provisions / reserves	3325	264,156	257,375
Total liabilities	3499	12,620,192	11,174,667

Equity	Code	Current year	Prior year
Common shares	3500	5,293,376	5,293,376
Retained earnings / deficit	3600	2,738,463	2,041,773
Total equity	3620	8,031,839	7,335,149
Total liabilities and equity	3640	20,652,031	18,509,816

Retained earnings	Code	Current year	Prior year
Retained earnings/deficit-start	3660	2,041,773	1,394,331
Net income / loss	3680	751,690	1,047,442
Cash dividends	3701	(600,000)	(400,000)
Other items affecting retained earnings	3740	545,000	
Total retained earnings	3849	2,738,463	2,041,773

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Canada Customs and Revenue Agency / Agence des douanes et du revenu du Canada

INCOME STATEMENT INFORMATION

Schedule 125

Details

Operating name, if different from the corporations' legal name
0001

Description of operation, if filing multiple Schedules 125
0002

Revenue	Code	Current year	Prior year
Trade sales of goods and services	8000	4,388,627	4,357,489
Total sales of goods and services	8089	4,388,627	4,357,489
Realized gains / losses on disposal of assets	8210	10,178	
Other revenue	8230	384,131	546,608
Total revenue	8299	4,782,936	4,904,097

Cost of sales	Code	Current year	Prior year
Opening inventory	8300		
Cost of sales	8518		
Gross profit / loss (item 8089 - item 8518)	8519	4,388,627	4,357,489

Operating expenses	Code	Current year	Prior year
Amortization of tangible assets	8670	893,443	838,632
Interest and bank charges	8710	79,219	25,397
Interest on long term debt	8714	507,950	507,500
Collection and credit costs	8717	407,717	440,288
Other expenses	9270	296,686	
Delivery, freight and express	9275	645,289	694,513
General and administrative expenses	9284	855,701	792,712
Total operating expenses	9367	3,686,005	3,299,042
Total expenses	9368	3,686,005	3,299,042
Net non-farming income	9369	1,096,931	1,605,055

Farming revenue	Code	Current year	Prior year
Grains and oilseeds	9370		
Total farm revenue	9659		

Farming expenses	Code	Current year	Prior year
Crop expenses	9660		
Total farm expenses	9898		
Net farm income	9899		
Net income / loss before taxes and extraordinary items	9970	1,096,931	1,605,055

Summary

Complete this section if only one Schedule 125 is filed, Schedule 140 is used to summarize the information from multiple Schedules 125.

Extraordinary items	9975	-	-	
Legal settlements	9976	-	-	
Unrealized gains / losses	9980	+	+	
Unusual items	9985	-	-	
Current income taxes	9990	- 355,241	-	557,613
Future income tax provision	9995	- (10,000)	-	
Total - Other comprehensive income	9998	+	+	
Net income / loss after taxes and extraordinary items	9999	= 751,690	=	1,047,442

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Schedule 141
Code 0801

NOTES CHECKLIST

- 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) for Corporations 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 preparing or reporting on the financial statements

Does the accountant have a professional designation?	095	[X] Yes	[ ] No
Is the accountant connected* with the corporation?	097	[ ] Yes	[X] No

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note
If the accountant does not have a professional designation or is connected with the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4 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	[ ] Yes	[X] No

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	[X] Yes	[ ] No
If yes, complete lines 102 to 107 below:			
Are any values presented at other than cost?	102	[ ] Yes	[X] No
Has there been a change in accounting policies since the last return?	103	[ ] Yes	[X] No
Are subsequent events mentioned in the notes?	104	[ ] Yes	[X] No
Is re-evaluation of asset information mentioned in the notes?	105	[ ] Yes	[X] No
Is contingent liability mentioned in the notes?	106	[X] Yes	[ ] No
Is information regarding commitments mentioned in the notes?	107	[ ] Yes	[X] No
Does the corporation have investments in joint venture(s) or partnership(s)?	108	[ ] Yes	[X] No
If yes, complete line 109 below:			
Are you filing financial statements of the joint venture(s) or partnership(s)?	109	[ ] Yes	[ ] No

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SCHEDULE 501
Code 1001

ONTARIO ADJUSTED TAXABLE INCOME OF ASSOCIATED CORPORATIONS TO DETERMINE SURTAX RE ONTARIO SMALL BUSINESS DEDUCTION

- For use by Canadian-controlled private corporations (CCPCs) to report the adjusted taxable income of all corporations (Canadian and foreign) with which the filing corporation was associated at any time during the tax year.
- Include the adjusted taxable income for the tax year of the associated corporation that ends at or before the date of the filing corporation's tax year-end.
- File this schedule with the *T2 Corporation Income Tax Return*.

Names of associated corporations * 100	Business number of associated corporations ** 200	Tax year-end 300	Adjusted taxable income (if loss, enter "0") *** 400
Town of Cobourg Holdings Inc	86511 7832 RC 0001	2009/12/31	0
Lakefront Generation Inc.	82428 6942 RC 0001	2009/12/31	0
Lakefront Lighting Inc.	85700 1424 RC 0001	2009/12/31	0
Cobourg Networks Inc	86512 5033 RC 0001	2009/12/31	89,879
		Total 500	89,879

Enter the total adjusted taxable income from line 500 on line J in Part 4 of Schedule 500, *Ontario Corporation Tax Calculation*.

* Subsection 256(2) of the federal *Income Tax Act* may deem the filing corporation to be associated with another corporation, because both corporations are associated with a third corporation. If so, do not list the other corporation, nor the third corporation if it is not a CCPC or has elected under subsection 256(2) of the federal Act not to be associated for purposes of section 125 of the federal Act.

** Enter "NR" if a corporation is not registered.

*** **Rules for adjusted taxable income:**

- If the associated corporation's tax year ends after December 31, 2008, its adjusted taxable income is equal to its taxable income or taxable income earned in Canada **plus** its adjusted Crown royalties **minus** its notional resource allowance for the year.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's adjusted taxable income by 365 and **divide** by the number of days in the associated corporation's tax year.
- If the associated corporation has two or more tax years ending in the filing corporation's tax year, enter the last tax year-end date on line 300 and, for the entry on line 400, **multiply** the sum of the adjusted taxable income for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.

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SCHEDULE 501
Code 1001

ONTARIO ADJUSTED TAXABLE INCOME OF ASSOCIATED CORPORATIONS TO DETERMINE SURTAX RE ONTARIO SMALL BUSINESS DEDUCTION

- For use by Canadian-controlled private corporations (CCPCs) to report the adjusted taxable income of all corporations (Canadian and foreign) with which the filing corporation was associated at any time during the tax year.
- Include the adjusted taxable income for the tax year of the associated corporation that ends at or before the date of the filing corporation's tax year-end.
- File this schedule with the *T2 Corporation Income Tax Return*.

Names of associated corporations * 100	Business number of associated corporations ** 200	Tax year-end 300	Adjusted taxable income (if loss, enter "0") *** 400
Town of Cobourg Holdings Inc	86511 7832 RC 0001	2009/12/31	0
Lakefront Generation Inc.	82428 6942 RC 0001	2009/12/31	0
Lakefront Lighting Inc.	85700 1424 RC 0001	2009/12/31	0
Cobourg Networks Inc	86512 5033 RC 0001	2009/12/31	89,879
		Total 500	89,879

Enter the total adjusted taxable income from line 500 on line J in Part 4 of Schedule 500, *Ontario Corporation Tax Calculation*.

* Subsection 256(2) of the federal *Income Tax Act* may deem the filing corporation to be associated with another corporation, because both corporations are associated with a third corporation. If so, do not list the other corporation, nor the third corporation if it is not a CCPC or has elected under subsection 256(2) of the federal Act not to be associated for purposes of section 125 of the federal Act.

** Enter "NR" if a corporation is not registered.

*** **Rules for adjusted taxable income:**

- If the associated corporation's tax year ends after December 31, 2008, its adjusted taxable income is equal to its taxable income or taxable income earned in Canada **plus** its adjusted Crown royalties **minus** its notional resource allowance for the year.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's adjusted taxable income by 365 and **divide** by the number of days in the associated corporation's tax year.
- If the associated corporation has two or more tax years ending in the filing corporation's tax year, enter the last tax year-end date on line 300 and, for the entry on line 400, **multiply** the sum of the adjusted taxable income for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.

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SCHEDULE 510
Code 0902

ONTARIO CORPORATE MINIMUM TAX

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act*, 2007 (Ontario).
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year*	112	20,652,031
Share of total assets from partnership(s) and joint venture(s)*	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	18,358,787
Total assets (total of lines 112 to 116)		39,010,818

Total revenue of the corporation for the tax year **	142	4,782,936
Share of total revenue from partnership(s) and joint venture(s)**	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	1,211,195
Total revenue (total of lines 142 to 146)		5,994,131

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the *Taxation Act, 2007* (Ontario) and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the *Taxation Act, 2007* (Ontario).

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the *Taxation Act, 2007* (Ontario) and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the *Taxation Act, 2007* (Ontario).

1
2

1

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Part 2 – Calculation of adjusted net income/loss for CMT purposes

Net income/loss per financial statements*			210	751,690
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220	355,241		
Provision for deferred income taxes (debits)/cost of future income taxes	222			
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends paid/payable to shareholders (other than dividends paid by credit unions)	230			
Other additions (see note below):				
Share of adjusted net income of partnerships and joint ventures**	228			
Total patronage dividends received, not already included in net income/loss	232			
281	282			
283	284			
Subtotal		355,241		355,241 A
Deduct (to the extent reflected in income/loss):				
Provision for recovery of current income taxes/benefit of current income taxes	320			
Provision for deferred income taxes (credits)/benefit of future income taxes	322	10,000		
Equity income from corporations	324			
Financial statement income from partnerships and joint ventures	326			
Dividends deductible under section 112, section 113 or subsection 138(6) of the federal Act	330			
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332			
Gain on donation of listed security or ecological gift	340			
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342			
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344			
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346			
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348			
Other deductions (see note below):				
Share of adjusted net loss of partnerships and joint ventures**	328			
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied by** 3	334			
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336			
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338			
381	382			
383	384			
385	386			
387	388			
389	390			
Subtotal		10,000		10,000 B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B).			490	1,096,931

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.
If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

2
3

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Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

Note

In accordance with *Ontario Regulation 37/09*, in calculating net income for CMT purposes, accounting income should be adjusted to remove unrealized gains and losses on mark-to-market property, as well as foreign currency gains and losses on assets, that are included in income for accounting purposes but not in income for income tax purposes. In later years, accounting income is adjusted in arriving at net income for CMT purposes by including these gains or losses when they are realized.

These realized gains and losses apply to the disposition of mark-to-market property:
- that is not capital property in the year;
- that is capital property and realized in the year or the preceding tax year that ends after March 23, 2007.

The mark-to-market rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal Bank Act, adjusted so consolidation and equity methods are not used.
- Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.
- Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.
- Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the *Taxation Act, 2007* (Ontario).

*** A joint election will be considered made under subsection 60(1) of the *Taxation Act, 2007* (Ontario) if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the *Taxation Act, 2007* (Ontario) if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the *Taxation Act, 2007* (Ontario) if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – Calculation of CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)					515	1,096,931	
Deduct:							
CMT loss available (amount R from Part 7)							
Minus: Adjustment for an acquisition of control *					518		
Adjusted CMT loss available							C
Net income subject to CMT calculation (if negative, enter "0")					520	1,096,931	
Amount from line 520	1,096,931 x	Number of days in the tax year before July 1, 2010 / Number of days in the tax year	365 / 365 x	4.0 % =		43,877	1
Amount from line 520	1,096,931 x	Number of days in the tax year after June 30, 2010 / Number of days in the tax year	x 365	2.7 % =			2
			Subtotal (amount 1 **plus** amount 2)			43,877	3
Gross CMT: amount on line 3 above x OAF **			100 %		540	43,877	
Deduct:							
Foreign tax credit for CMT purposes ***					550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")						43,877	D
Deduct:							
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)						146,167	
Net CMT payable (if negative, enter "0")							E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Portion of CMT loss available that exceeds the adjusted net income for the tax year from business(es) continued from before the acquisition of control. See subsection 58(3) of the Taxation Act, 2007 (Ontario).

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario", enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple", complete the following calculation and enter the result on line F:

Ontario taxable income **** / Taxable income ***** = _____

Ontario allocation factor	1.00000	F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

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Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year*		G	
Deduct:			
CMT credit expired*	600		
CMT credit carryforward at the beginning of the current tax year * (see note below)		620	
Add:			
CMT credit carryforward balances transferred on an amalgamation or the wind-up of a subsidiary (see note below)		650	
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)			H
Deduct:			
CMT credit deducted in the current tax year (amount P in Part 5)			I
Subtotal (amount H **minus** amount I)			J
Add:			
Net CMT payable (amount E from Part 3)			
SAT payable (amount O from Part 6 of Schedule 512)			
Subtotal			K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)		670	L

* For the first tax year that includes days in 2009:
- do not enter an amount on line G or line 600.
- for line 620, enter the amount from line 2336 of Ontario *CT23 Schedule 101 Corporate Minimum Tax (CMT)* for the last tax year ending in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)				M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		146,167 1		
For a corporation that is not a life insurance corporation:				
CMT after foreign tax credit deduction (amount D from Part 3)	43,877 2			
For a life insurance corporation:				
Gross CMT (line 540 from Part 3)	3			
Gross SAT (line 460 from Part 6 of Schedule 512)	4			
The greater of amounts 3 and 4	5			
Deduct: line 2 or line 5, whichever applies:		43,877 6		
Subtotal (if negative, enter "0")		102,290		102,290 N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		146,167		
Deduct: Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)				
Subtotal (if negative, enter "0")		146,167		146,167 O
CMT credit deducted in the current tax year (least of amounts M, N, and O)				P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☐

If you answered yes to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the *Taxation Act, 2007* (Ontario).

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Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if you are reporting a CMT credit carryforward at the beginning of the tax year on line 620, or a CMT credit carryforward transferred on an amalgamation or the wind-up of a subsidiary on line 650. For more information on how to complete this part, see the T2 Corporation – Income Tax Guide.

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year 2000/12/31	681
8th previous tax year 2001/12/31	682
7th previous tax year 2002/12/31	683
6th previous tax year 2003/12/31	684
5th previous tax year 2004/12/31	685
4th previous tax year 2005/12/31	686
3rd previous tax year 2006/12/31	687
2nd previous tax year 2007/12/31	688
1st previous tax year 2008/12/31	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation and subsidiaries wound-up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * — Q

Deduct:

CMT loss expired* — 700

CMT loss carryforward at the beginning of the tax year * (see note below) — 720

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) — 750

CMT loss available (line 720 **plus** line 750) — R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3)

Subtotal (if negative, enter "0") — S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, **if negative**) (enter as a positive amount) — 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) — 770 — T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700.
- for line 720, enter the amount from line 2214 of Ontario *CT23 Schedule 101 Corporate Minimum Tax (CMT)* for the last tax year ending in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not transfer a loss on a vertical amalgamation under subsection 87(2.11) of the federal Act or other amalgamation of a parent and its subsidiary.

Note : If you entered an amount on line 720 or line 750, complete Part 8.

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Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if you are reporting a CMT loss carryforward at the beginning of the tax year on line 720 or a CMT loss transferred on an amalgamation on line 750. For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

Year of origin	Balance earned in a tax year ending before March 24, 2007 *	Balance earned in a tax year ending after March 23, 2007 **
10th previous tax year	810	820
9th previous tax year 2000/12/31	811	821
8th previous tax year 2001/12/31	812	822
7th previous tax year 2002/12/31	813	823
6th previous tax year 2003/12/31	814	824
5th previous tax year 2004/12/31	815	825
4th previous tax year 2005/12/31	816	826
3rd previous tax year 2006/12/31	817	827
2nd previous tax year 2007/12/31	818	828
1st previous tax year 2008/12/31		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound-up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 24, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 23, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

1

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Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 511
Code 0901

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporations' share of any partnership(s)/joint venture(s) total assets and total revenue.
- File this schedule with the T2 Corporation Income Tax Return.

Names of associated corporations 200	Business number Canadian corporation only (see Note 1) 300	Total assets * (see Note 2) 400	Total revenue ** (see Note 2) 500
Town of Cobourg Holdings Inc	86511 7832 RC 0001	14,181,089	641,207
Lakefront Utilities Services Inc	86906 0327 RC 0001	1,323,350	1
Lakefront Generation Inc.	82428 6942 RC 0001	65	2
Lakefront Lighting Inc.	85700 1424 RC 0001	973,495	205,008
Cobourg Networks Inc	86512 5033 RC 0001	1,880,788	364,977
	Total	450 18,358,787	550 1,211,195

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate MinimumTax*.

Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter "NR" if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has two or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has two or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

2

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Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 515
Code 0901

ONTARIO CAPITAL TAX ON OTHER THAN FINANCIAL INSTITUTIONS

- Complete this schedule for a corporation other than a financial institution with a permanent establishment in Ontario at any time in the tax year. The Ontario capital tax on other than financial institutions is levied under section 64 of the *Taxation Act, 2007* (Ontario).
- To complete this schedule, you have to complete Schedule 33, *Part I.3 Tax on Large Corporations*. File completed copies of both schedules with the *T2 Corporation Income Tax Return* within six months of the end of the tax year.
- A corporation is exempt from Ontario capital tax if it was one of the following:

1) a corporation that is liable to the special additional tax according to section 74 of the *Corporations Tax Act* (Ontario);
2) a credit union;
3) a deposit insurance corporation according to section 137.1 of the federal *Income Tax Act*;
4) a family farm corporation, as defined by subsection 64(3) of the *Taxation Act, 2007* (Ontario);
5) a family fishing corporation, as defined by subsection 64(3) of the *Taxation Act, 2007* (Ontario); or
6) a corporation exempt from income tax according to section 149 of the federal *Income Tax Act*.

Part 1 – Taxable capital of a corporation resident in Canada other than a financial institution

Amount A from Part 1 of Schedule 33	100	17,113,995	
Add:			
Accumulated other comprehensive income at the end of the year	105		
Subtotal		17,113,995	▶ 17,113,995 A
Deduct:			
Amount B from Part 1 of Schedule 33	110		
Amount on line 490 from Part 2 of Schedule 33	115		
Subtotal			▶ B
Taxable capital (amount A **minus** amount B) (if negative, enter "0")	120		17,113,995

Part 2 – Capital deduction

Complete this part only if the corporation is associated.

Are you electing under subsection 83(2) of the *Taxation Act, 2007* (Ontario)? 190 1 Yes [X] 2 No [ ]

If you answered **no** to the question at line 190, complete line 220. If you answered **yes** to the question at line 190, complete line 305 by using Schedule 516, *Capital Deduction Election of Associated Group for the Allocation of Net Deduction*, to calculate the amount to be entered on line 300.

Taxable capital (from line 120) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (from line 790 in Part 4 of Schedule 33)	200		x $15,000,000 = **Capital deduction**	220
Taxable capital or taxable capital employed in Canada of every corporation with a permanent establishment in Canada and associated for the last tax year *	210			

* This amount includes the filing corporation's taxable capital or taxable capital employed in Canada. Do not include an amount from a financial institution or corporation that is exempt from capital tax under Division E of the *Taxation Act*, 2007 (Ontario) or Part III of the *Corporations Tax Act* (Ontario).

Allocation of net deduction (from line 600 for the filing corporation from Schedule 516)	300	15,000,000	= **Capital deduction**	305 15,000,000
Ontario allocation factor (OAF) (amount I in Part 3)		1.00000		
		OAF		

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Part 3 – Ontario capital tax payable

Taxable capital (enter amount from line 120 in Part 1) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (enter amount from line 790 in Part 4 of Schedule 33), whichever applies						320	17,113,995
Deduct: Capital deduction (Enter $15,000,000 if the corporation is not associated. Otherwise, enter the amount from line 220 or line 305, whichever applies, from Part 2)							15,000,000 B
Net amount (line 320 **minus** amount B) (if negative, enter "0")							2,113,995 C
Amount C	2,113,995 x	Number of days in the tax year before January 1, 2010 / Number of days in the tax year	365 / 365	X	0.00225 =		4,756 D
Amount C	2,113,995 x	Number of days in the tax year after December 31, 2009 and before July 1, 2010 / Number of days in the tax year	/ 365	X	0.00150 =		E
					Subtotal (amount D **plus** amount E)		4,756 F
Amount F	4,756 x	OAF (amount on line I)	1.00000 =				4,756 G
Amount G	4,756 x	Number of days in the tax year * / 365	365 / 365 =				4,756 H
Deduct: Capital tax credit for manufacturers (enter amount J from Part 4).						350	
Ontario capital tax payable (amount H **minus** line 350) (if negative, enter "0")						400	4,756

Enter amount from line 400 on line 282 of Schedule 5, *Tax Calculation Supplementary - Corporations*.

* Enter either 365 if there are at least 51 weeks in the tax year, or the number of days in the year, whichever applies.

Calculation of the Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario", enter "1" on line I.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple", complete the following calculation and enter the result on line I:

Ontario taxable income ** / Taxable income *** =

Ontario allocation factor 1.00000 I

** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*** Enter the taxable income amount from line 360 or line Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Capital tax credit for manufacturers

Ontario manufacturing labour cost* 405 / Ontario labour cost** 410 = 420 %

If the percentage on line 420 is 20% or less, enter "0" on line J.
If the percentage on line 420 is at least 50%, enter amount H from Part 3 on line J.
If the percentage on line 420 is more than 20% but less than 50%, complete the following calculation and enter the result on line J:

(percentage from line 420) - 20% / 30% = % / 30% x Amount H from Part 3 = 4,756

Capital tax credit for manufacturers J

Enter amount J on line 350 in Part 3.

* As defined in subsection 83.1(4) of the *Taxation Act, 2007* (Ontario)
** As defined in subsection 83.1(5) of the *Taxation Act, 2007* (Ontario)

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Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 516
Code 0901

CAPITAL DEDUCTION ELECTION OF ASSOCIATED GROUP FOR THE ALLOCATION OF NET DEDUCTION

- Complete this schedule to allocate the associated group's net deduction for the capital deduction election under subsection 83(2) of the *Taxation Act, 2007* (Ontario). The associated group includes the filing corporation (see line 190 of Part 2 of Schedule 515, *Ontario Capital Tax on Other than Financial Institutions*.
- File this schedule with the *T2 Corporation Income Tax Return*.

A Names of eligible corporations in the associated group 100	B Business Number of associated corporations (enter "NR" if a corporation is not registered) 200	C Ontario allocation factor (OAF) * (enter as a percentage) 300	D Total assets ** 400	E Net deduction ($15 million x line 300) **multiplied by** line 400 / line 700 500	F Allocation of net deduction *** 600
Lakefront Utilities Inc.	86512 5231 RC 0001	100.000	18,509,816	7,565,275	15,000,000
Town of Cobourg Holdings Inc	86511 7832 RC 0001	100.000	14,181,661	5,796,285	
Lakefront Utilities Services Inc	86906 0327 RC 0001	100.000	1,475,535	603,076	
Lakefront Generation Inc.	82428 6942 RC 0001	100.000	2,846	1,163	
Lakefront Lighting Inc.	85700 1424 RC 0001	100.000	684,843	279,907	
Cobourg Networks Inc	86512 5033 RC 0001	100.000	1,845,515	754,293	

Total assets of associated group (total of amounts in column D) 700: 36,700,216

Total net deduction (total of amounts in column E) 800: 15,000,000

Total allocated net deduction (total of amounts in column F) (not to exceed amount on line 800) 900: 15,000,000

* OAF from the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends.

** Total assets of each corporation in the associated group as recorded in the books and records for the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends. If the corporation is not resident in Canada, enter the amount of its total assets situated in Canada.

*** Enter the amount from this column allocated to the filing corporation on line 300 of Schedule 515.

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Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546
Code 0901

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the *Business Corporations Act* (BCA) or *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. For more information, visit **www.ServiceOntario.ca**.
- 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)		
Lakefront Utilities Inc.		
Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	110 Date of incorporation or amalgamation, whichever is the most recent	120 Ontario Corporation No.
Ontario	2000/05/01	1412420

Part 2 – Head or registered office address: (P.O. box not acceptable)

200 Care of (if applicable)			
210 Street number	220 Street name		230 Suite number
207	Division Street		
240 Additional address information			
250 Municipality (e.g., city, town)	260 Province	270 Country	280 Postal code
Cobourg	ON	CA	K9A 4L3

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 with respect to names, addresses for service, and the date elected/appointed and date ceased of the directors and five most senior officers, or the corporation's mailing address or language of preference? Obtain a Corporation Profile Report to review the information shown for the corporation on the public record maintained by the MGS. 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 Cunningham (Last name) **451** Stewart (First name) **454** _____ (Middle name(s))

460 2

Please enter one of the following numbers in this box for the above-named person: enter **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.

Client: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2009/12/31 Printed: 2010/06/18 19:53

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		**540** Suite number
550 Additional address information			
560 Municipality (e.g., city, town)	**570** Province/state	**580** Country	**590** Postal/zip code

Part 6 – Language of preference

600 Indicate your language preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communication with the corporation. This may be different from line 990 on the T2 return.

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Instalments

Federal tax instalments

This worksheet is provided for estimation purposes only and should not be relied upon solely to schedule installment payments. Always verify installment payment requirements according to the latest T7B-CORP as well as any schedule of installment payments issued by the CRA and/or Provincial authority upon assessment.

Instalment base

Year-end	Estimate for current year 2010/12/31	First instalment base 2009/12/31	Second instalment base 2008/12/31
Taxable income		1,129,302	1,734,279
Base amount of Part I tax		429,135	659,026
Corporate surtax			
Recapture of investment tax credit			
Refundable tax on CCPC's investment income			
Small business deduction		15,776	15,171
Federal tax abatement		112,930	173,428
Manufacturing and processing profits deduction			
Foreign tax credits			
Tax reductions		93,285	139,828
Political contribution tax credit			
Investment tax credit			
Other credits			
Part I tax payable		207,144	330,599
Part I.3 tax payable			
Part VI tax payable			
Part VI.1 tax payable			
Part XIII.1 tax payable			
Net provincial or territorial tax payable (excluding Ontario)			
Ontario - Single administration			
Income tax payable		146,167	242,799
Corporate minimum tax payable			
Capital tax payable		4,756	1,695
Ontario special additional tax on life insurance corporations			
Total tax payable		358,067	575,093
Days in taxation year	365	365	365
Tax payable adjusted for short taxation years		358,067	575,093
Estimated credits for the current year:			
Investment tax credit refund			
Dividend refund			
Other federal credits			
Other provincial credits			
Total estimated credits			
Instalment base (excludes federal and/or provincial component on or below the $3,000 threshold)		358,067	575,093
Monthly payment		29,839	47,924

Instalment payment options

☐ 1. based on estimated taxes for the current year
☒ 2. based on the first instalment base
☐ 3. based on the first and second instalment base
☐ 4. instalments are not required

Does the corporation qualify for quarterly Instalments*? ☐ Yes ☐ 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

Instalment payments

Date	Instalments required	Instalments paid	Instalments payable
2010/01/31	29,839		
2010/02/28	29,839		
2010/03/31	29,839		
2010/04/30	29,839		
2010/05/31	29,839		
2010/06/30	29,839		179,034
2010/07/31	29,839		29,839
2010/08/31	29,839		29,839
2010/09/30	29,839		29,839
2010/10/31	29,839		29,839
2010/11/30	29,839		29,839
2010/12/31	29,839		29,839
Total	358,068		358,068

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2010 LUI TAX RETURN

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200 Code 1001

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Ontario (for tax years ending before 2009), Quebec, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, and paragraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre 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 86512 5231 RC 0001

Corporation's name

002 Lakefront Utilities Inc.

Address of head office

Has this address changed since the last time you filed your T2 return? 010 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 011 to 018)

011 207 Division Street

012

City: 015 Cobourg — Province, territory, or state: 016 ON

Country (other than Canada): 017 — Postal code/Zip code: 018 K9A 4L3

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? 020 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 021 to 028)

021 c/o

022 207 Division Street

023

City: 025 Cobourg — Province, territory, or state: 026 ON

Country (other than Canada): 027 — Postal code/Zip code: 028 K9A 4L3

Location of books and records

Has the location of books and records changed since the last time you filed your T2 return? 030 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 031 to 038)

031 207 Division Street

032

City: 035 Cobourg — Province, territory, or state: 036 ON

Country (other than Canada): 037 — Postal code/Zip code: 038 K9A 4L3

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

To which tax year does this return apply?

Tax year start: 060 2010/01/01 — Tax year-end: 061 2010/12/31

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

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1) ? 066 1 Yes ☐ 2 No ☒

Is the corporation a professional corporation that is a member of a partnership? 067 1 Yes ☐ 2 No ☒

Is this the first year of filing after:

Incorporation? 070 1 Yes ☐ 2 No ☒

Amalgamation? 071 1 Yes ☐ 2 No ☒

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? 072 1 Yes ☐ 2 No ☒

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? 076 1 Yes ☐ 2 No ☒

Is this the final return up to dissolution? 078 1 Yes ☐ 2 No ☒

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

091	092	093	094	095	096
100					

T2 E (10) Version 2010.4.3 GP41 - **RETAIN ON FILE. DO NOT SUBMIT TO THE CRA**

Canada

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Client: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2010/12/31 Printed: 2011/06/02 12:29

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules - Answer the following questions. For each **yes** response, **attach** to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **Yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		-----
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	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) is the corporation claiming the refundable portion of Part I tax?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210		10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	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?	255		92 *

*** We do not print this schedule.**

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Attachments - Continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256	☐	T1134-A
Did the corporation have any controlled foreign affiliates?	258	☐	T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259	☐	T1135
Did the corporation transfer or loan property to a non-resident trust?	260	☐	T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261	☐	T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262	☐	T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263	☐	T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264	☐	T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	☐	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266	☐	T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267	☐	T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	☒	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269	☐	54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	1 Yes ☐	2 No ☒
Is the corporation inactive?	280	1 Yes ☐	2 No ☒
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281	1 Yes ☐	2 No ☒
What is the corporation's major business activity? (Only complete if **yes** was entered at line 281.)	282		
If the major business activity involves the resale of goods, show whether it is wholesale or retail	283	1 Wholesale ☐	2 Retail ☐

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.	284	Distribution of Electricity	285	100.000 %
	286		287	%
	288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes ☐	2 No ☒
Did the corporation emigrate from Canada during the tax year?	292	1 Yes ☐	2 No ☒
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		
If the corporation's major business activity is construction, did you have any sub-contractors during the tax year?	295	1 Yes ☐	2 No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI			300 927,621	A
Deduct: Charitable donations from Schedule 2	311			
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction *	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal			▶	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			927,621	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355	D
Taxable income (amount C **plus** amount D)			360 927,621	
Income exempt under paragraph 149(1)(t)			370	
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724 on page 8.

1

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Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 — **400** 927,621 A

Taxable income from line 360 on page 3, **minus** 10/3 of the amount on line 632* on page 7, **minus** 3 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** 927,621 B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

$400,000 x (Number of days in the tax year before 2009 / Number of days in the tax year) = 1

$500,000 x (Number of days in the tax year after 2008 / Number of days in the tax year) = 365/365 = 500,000 2

Add amounts at lines 1 and 2 — 500,000 4

Business limit (see notes 1 and 2 below) — **410** 500,000 C

Notes: 1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 X **415** *** 11,250 D / 11,250 = 500,000 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") — **425** 0 F

Small business deduction

Amount A, B, C, or F whichever is the least ____ X (Number of days in the tax year before January 1, 2008 / Number of days in the tax year) 365 x 16% = ____ 5

Amount A, B, C, or F whichever is the least ____ X (Number of days in the tax year after December 31, 2007 / Number of days in the tax year) 365/365 x 17% = ____ 6

Total of amounts 5 and 6 - enter on line 9 of page 7 — **430** 0 G

* Calculate the amount of foreign non-business income tax credit deductible at line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and the previous tax years, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3			927,621 A
Lesser of amounts V and Y from Part 9 of Schedule 27		B	
Amount QQ from Part 13 of Schedule 27		C	
Amount used to calculate the credit union deduction from Schedule 17		D	
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least		E	
Aggregate investment income from line 440 of page 6		F	
Total of amounts B to F		▶	G
Amount A **minus** amount G (if negative, enter "0")			927,621 H

Amount H	927,621	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365	x 7% =	I
Amount H	927,621	x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year	365	x 8.5% =	J
Amount H	927,621	x	Number of days in the tax year after December 31, 2008 and before January 1, 2010 / Number of days in the tax year	365	x 9% =	K.1
Amount H	927,621	x	Number of days in the tax year after December 31, 2009 and before January 1, 2011 / Number of days in the tax year	365 / 365	x 10% =	92,762 K.2
Amount H	927,621	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	x 11.5% =	K.3
Amount H	927,621	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	365	x 13% =	L

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L 92,762 M

Enter amount M on line 638 of page 7.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, 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)			N
Lesser of amounts V and Y from Part 9 of Schedule 27		O	
Amount QQ from Part 13 of Schedule 27		P	
Amount used to calculate the credit union deduction from Schedule 17		Q	
Total of amounts O to Q		▶	R
Amount N **minus** amount R (if negative, enter "0")			S

Amount S		x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year		x 7% =	T
Amount S		x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year		x 8.5% =	U
Amount S		x	Number of days in the tax year after December 31, 2008 and before January 1, 2010 / Number of days in the tax year		x 9% =	V.1
Amount S		x	Number of days in the tax year after December 31, 2009 and before January 1, 2011 / Number of days in the tax year		x 10% =	V.2
Amount S		x	Number of days in the tax year after December 31, 2010 and before January 1, 2012 / Number of days in the tax year		x 11.5% =	V.3
Amount S		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year		x 13% =	W

General tax reduction – Total of amounts T to W X

Enter amount X on line 639 of page 7.

1

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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			927,621	
Deduct: Amount on line 400, 405, 410, or 425 on page 4, whichever is the least				
Foreign non-business income tax credit from line 632 of page 7		x 25/9 =		
Foreign business income tax credit from line 636 of page 7		x 3 =		
			927,621 X 26 2/3% =	247,366 D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8)			166,972	
Deduct: Corporate surtax				
Net amount			166,972	166,972 E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least			450	0 F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	460		
Deduct: Dividend refund for the previous tax year	465		G
Add the total of:			
Refundable portion of Part I tax from line 450 above			
Total Part IV tax payable from Schedule 3			
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480		H
Refundable dividend tax on hand at the end of the tax year - Amount G **plus** amount H	485		0

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	X 1/3	I
Refundable dividend tax on hand at the end of the tax year from line 485 above		J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 of page 8)		0

1

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Part I tax

Base amount of Part I tax

taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38%			550 352,496	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	927,621			
Deduct: Amount on line 400, 405, 410, or 425 of page 4, whichever is the least				
Net amount	927,621	927,621 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)	352,496	D

Deduct:

Small business deduction from line 430 on page 4		9		
Federal tax abatement	608	92,762		
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 M on page 5	638	92,762		
General tax reduction from amount X 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			
	Subtotal	185,524	185,524	E
Part I tax payable -- Line D **minus** line E			166,972	F

Enter amount F on line 700 of page 8.

1

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Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	166,972
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		166,972

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 Ontario [for tax years ending before 2009], Quebec, and Alberta)	760	92,494	
Provincial tax on large corporations (New Brunswick* and Nova Scotia)	765		
		92,494 ▶	92,494
Total tax payable	770		259,466 A

* The New Brunswick tax on large corporations is eliminated effective January 1, 2009.

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	4	
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	325,155	
Total credits	890	325,159	325,159 B
Balance (line A **minus** line B)			(65,693) I

Refund Code 894 1 Overpayment 65,693

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 ☒ NA ☐

Certification

I, 950 Cunningham (Last name) 951 Stewart (First name) 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 further 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 2011/06/02 (Date) Signature of the authorized signing officer of the corporation
956 (905) 372-2193 Telephone number

Is the contact person the same as the authorized signing officer? If *no*, complete the information below. 957 1 Yes ☒ 2 No ☐

958 Name 959 ( ) - Telephone number

Language of correspondence - Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French. 990 1
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.

1

Client: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2010/12/31 Printed: 2011/06/02 12:29

Canada Revenue Agency / Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

Schedule 1
Code 0901

- 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			A	609,948
Add:				
Provision for income taxes - current	101	254,247		
Provision for income taxes - deferred	102	40,000		
Amortization of tangible assets	104	894,073		
Reserves from financial statements - balance at the end of the year	126	268,943		
Total of lines 101 to 199	500	1,457,263	▶	1,457,263
Deduct:				
Capital cost allowance from Schedule 8	403	875,434		
Reserves from financial statements - balance at the beginning of the year	414	264,156		
Total of lines 401 to 499	510	1,139,590	▶	1,139,590
Net income (loss) for income tax purposes - enter on line 300 on page 3 of the T2 return				927,621

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Canada Revenue Agency / Agence du revenu du Canada

Schedule 5
Code 1001

TAX CALCULATION SUPPLEMENTARY - CORPORATIONS

Part 1 - Allocation of taxable income

100 402 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 attributable to jurisdiction	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		927,621
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		927,621

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking center; 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 on the following pages.

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Part 2 - Provincial and territorial tax payable, tax credits, and rebates

Newfoundland and Labrador

Newfoundland and Labrador tax before credits 200

Add: Newfoundland and Labrador offshore tax 205

Gross Newfoundland and Labrador tax → A1

Deduct:

Newfoundland and Labrador political contribution tax credit 500

Contribution 891

Newfoundland and Labrador foreign tax credit (from Schedule 21) 501

Newfoundland and Labrador manufacturing and processing profits tax credit (from Schedule 300) 503

Newfoundland and Labrador direct equity tax credit (from Schedule 303) 505

Newfoundland and Labrador resort property investment tax credit (from Schedule 304) 507

Newfoundland and Labrador small business tax holiday * 511

Small business tax holiday certificate number (from Form NLSBTH) 832

Subtotal → B1

Subtotal (amount A1 **minus** amount B1) (if negative, enter "0") C1

Add::

Newfoundland and Labrador capital tax on financial institutions (from Schedule 305) 518

Total Newfoundland and Labrador tax payable before refundable credits (amount C1 **plus** amount on line 518) (if negative, enter "0") D1

Deduct:

Newfoundland and Labrador research and development tax credit (from Schedule 301) 520

Newfoundland and Labrador film and video industry tax credit 521

Certificate number 821

Subtotal → E1

Net Newfoundland and Labrador tax payable or refundable credit (amount D1 **minus** amount E1) 209 F1

(if a credit, enter amount in brackets) Include this amount on line 255.

* The amount of Newfoundland and Labrador small business tax holiday cannot be more than the gross Newfoundland and Labrador tax **minus** all other Newfoundland and Labrador tax credits (including the refundable credits).

Prince Edward Island

Prince Edward Island tax before credits 210 A2

Deduct:

Prince Edward Island political contribution tax credit 525

Contribution 892

Prince Edward Island foreign tax credit (from Schedule 21) 528

Prince Edward Island corporate investment tax credit (from Schedule 321) 530

Subtotal → B2

Net Prince Edward Island tax payable (amount A2 **minus** amount B2) (if negative, enter "0") 214 C2

Include this amount on line 255.

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Part 2 - Provincial and territorial tax payable, tax credits, and rebates (continued)

Nova Scotia

Nova Scotia tax before credits (from Schedule 346)		215		
Add:				
Nova Scotia offshore tax (from Schedule 346)		220		
Recapture of Nova Scotia research and development tax credit (from Schedule 340)		221		
Gross Nova Scotia tax				A3
Deduct:				
Nova Scotia political contribution tax credit		550		
Contribution	893			
Nova Scotia foreign tax credit (from Schedule 21)		554		
Nova Scotia manufacturing and processing investment tax credit (from Schedule 344)		561		
Nova Scotia corporate tax reduction for new small businesses * (from Schedule 341)		556		
Certificate number	834			
Manufacturing and processing investment tax credit (10%)				
	Subtotal			B3
Total Nova Scotia tax payable before refundable credits (amount A3 **minus** amount B3) (if negative, enter "0")				C3
Deduct:				
Nova Scotia film industry tax credit **		565		
Certificate number	836			
Nova Scotia research and development tax credit (from Schedule 340)		566		
Nova Scotia digital media tax credit **		567		
Certificate number	838			
	Subtotal			D3
Net Nova Scotia tax payable or refundable credit (amount C3 **minus** amount D3) (if a credit, enter amount in brackets) Include this amount on line 255.		224		E3

* The amount of Nova Scotia corporate tax reduction for new small businesses cannot be more than the gross Nova Scotia tax **minus** all other Nova Scotia tax credits (including the refundable credits).

** To claim the credit, file the original or a copy of the certificate with your T2 return.

New Brunswick

New Brunswick tax before credits (from Schedule 366)		225		
Add:				
Recapture of New Brunswick research and development tax credit (from Schedule 360)		573		
Gross New Brunswick tax				A4
Deduct:				
New Brunswick political contribution tax credit		575		
Contribution	894			
New Brunswick foreign tax credit (from Schedule 21)		576		
New Brunswick non-refundable research and development tax credit (from Schedule 360)		577		
	Subtotal			B4
Total New Brunswick tax payable before refundable credits (amount A4 **minus** amount B4) (if negative, enter "0")				C4
Deduct:				
New Brunswick film tax credit		595		
Certificate number	850			
New Brunswick refundable research and development tax credit (from Schedule 360)		597		
	Subtotal			D4
Net New Brunswick tax payable or refundable credit (amount C4 **minus** amount D4) (if a credit, enter amount in brackets) Include this amount on line 255.		229		E4

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Part 2 - Provincial and territorial tax payable, tax credits, and rebates (continued)

Ontario

(2009 and later tax years only)

Ontario basic income tax (from Schedule 500)	270	120,515		
Deduct: Ontario small business deduction (from Schedule 500)	402	39,979		
Subtotal (if negative, enter "0")		80,536 ▶	80,536	A6
Add:				
Surtax re Ontario small business deduction (from Schedule 500)	272	9,012		
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		9,012 ▶	9,012	B6
Subtotal (amount A6 **plus** amount B6)			89,548	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 contribution tax credit (from Schedule 525)	415			
Subtotal		▶		D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")			89,548	E6
Ontario research and development tax credit (from Schedule 508)	416			
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")			89,548	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")			89,548	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	2,946		
Subtotal		2,946 ▶	2,946	H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)			92,494	I6
Deduct:				
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452			
Ontario apprenticeship training tax credit (from Schedule 552)	454			
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			
Subtotal		▶		J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter amount in brackets) Include this amount on line 255.	290		92,494	K6

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Part 2 - Provincial and territorial tax payable, tax credits, and rebates (continued)

Manitoba

Manitoba tax before credits (from Schedule 383) — 230 — A7

Deduct:

Manitoba foreign tax credit (from Schedule 21)	601		
Manitoba manufacturing investment tax credit (from Schedule 381)	605		
Manitoba research and development tax credit (from Schedule 380)	606		
Manitoba co-op education and apprenticeship tax credit (from Schedule 384)	603		
Manitoba odour-control tax credit (from Schedule 385)	607		
Manitoba small business venture capital tax credit (from Schedule 387)	608		
Subtotal			B7

Total Manitoba tax payable before refundable credits (amount A7 **minus** amount B7) (if negative, enter "0") — C7

Deduct:

Manitoba cooperative development tax credit	612		
Manitoba refundable research and development tax credit (from Schedule 380)	613		
Manitoba interactive digital media tax credit	614		
Manitoba book publishing tax credit (from Schedule 389)	615		
Manitoba green energy equipment tax credit	619		
Manitoba film and video production tax credit *	620		
Certificate number 856			
Manitoba refundable manufacturing investment tax credit (from Schedule 381)	621		
Manitoba refundable co-op education and apprenticeship tax credit (from Schedule 384)	622		
Manitoba refundable odour-control tax credit for agricultural corporations (from Schedule 385)	623		
Subtotal			D7

Net Manitoba tax payable or refundable credit (amount C7 **minus** amount D7) — 234 — E7
(if a credit, enter amount in brackets) Include this amount on line 255.

* If you received a certificate from the Manitoba Department of Finance it should be claimed on line 620. If you have more than one certificate, use Schedule 382. If the certificate was issued by Manitoba Film and Sound Recording Development Corporation, complete Schedule 388, *Manitoba Film and Video Production Tax Credit*, to calculate the amount of the credit and enter your claim on line 620.

Saskatchewan

Saskatchewan tax before credits (from Schedule 411) — 235 — A8

Deduct:

Saskatchewan political contribution tax credit	624		
Contribution 890			
Saskatchewan foreign tax credit (from Schedule 21)	625		
Saskatchewan manufacturing and processing profits tax reduction (from Schedule 404)	626		
Saskatchewan manufacturing and processing investment tax credit (from Schedule 402)	630		
Saskatchewan research and development tax credit (from Schedule 403)	631		
Saskatchewan royalty tax rebate (from Schedule 400)	632		
Subtotal			B8

Total Saskatchewan tax payable before refundable credits (amount A8 **minus** amount B8) (if negative, enter "0") — C8

Deduct:

Saskatchewan qualifying environmental trust tax credit	641		
Saskatchewan film employment tax credit	643		
Certificate number 860			
Saskatchewan refundable manufacturing and processing investment tax credit (from Schedule 402)	644		
Saskatchewan refundable research and development tax credit (from Schedule 403)	645		
Subtotal			D8

Net Saskatchewan tax payable or refundable credit (amount C8 **minus** amount D8) — 239 — E8
(if a credit, enter amount in brackets) Include this amount on line 255.

1

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Part 2 - Provincial and territorial tax payable, tax credits, and rebates (continued)

British Columbia

British Columbia tax before credits (from Schedule 427) 240

Add:

Recapture of British Columbia scientific research and experimental development (SR&ED) tax credit (from Form T666) 241

Gross British Columbia tax → A10

Deduct:

British Columbia foreign tax credit (from Schedule 21) 650

British Columbia logging tax credit 651

British Columbia political contribution tax credit 653

Contribution 896

British Columbia small business venture capital tax credit 656

Credit at the end of previous tax year 880

Current-year credit 881

Certificate number (from SBVC 10) 882

British Columbia manufacturing and processing tax credit (from Schedule 426) 660

British Columbia SR&ED non-refundable tax credit (from Form T666) 659

Subtotal → B10

Total British Columbia tax payable before refundable credits (amount A10 **minus** amount B10) (if negative, enter "0") C10

Deduct:

British Columbia qualifying environmental trust tax credit 670

British Columbia film and television tax credit (from Form T1196) 671

British Columbia production services tax credit (from Form T1197) 672

British Columbia mining exploration tax credit (from Schedule 421) 673

British Columbia SR&ED refundable tax credit (from Form T666) 674

British Columbia book publishing tax credit (amount on line 886 multiplied by 90%) 665

Base amount of Publishing support * contributions received in the tax year 886

British Columbia training tax credit (from Schedule 428) 679

British Columbia interactive digital media tax credit (from Schedule 429) 680

Subtotal → D10

Net British Columbia tax payable or refundable credit (amount C10 **minus** amount D10) 244 E10

(if a credit, enter amount in brackets) Include this amount on line 255.

* Previously Book Publishing Industry Development Program.

Yukon

Yukon tax before credits (from Schedule 443) 245 A11

Deduct:

Yukon political contribution tax credit 675

Contribution 897

Yukon foreign tax credit (from Schedule 21) 676

Yukon manufacturing and processing profits tax credit (from Schedule 440) 677

Subtotal → B11

Total Yukon tax payable before refundable credits (amount A11 **minus** amount B11) (if negative, enter "0") C11

Deduct:

Yukon mineral exploration tax credit (from Schedule 441) 697

Yukon research and development tax credit (from Schedule 442) 698

Subtotal → D11

Net Yukon tax payable or refundable credit (amount C11 **minus** amount D11) 249 E11

(if a credit, enter amount in brackets) Include this amount on line 255.

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Part 2 - Provincial and territorial tax payable, tax credits, and rebates (continued)

Northwest Territories

Northwest Territories tax before credits			250	A12
Deduct:				
Northwest Territories political contribution tax credit		700		
Contribution	898			
Northwest Territories foreign tax credit (from Schedule 21)		701		
Northwest Territories investment tax credit (from Schedule 460)		705		
	Subtotal			B12
Net Northwest Territories tax payable (amount A12 **minus** amount B12) (if negative, enter "0")			254	C12

Include this amount on line 255.

Nunavut

Nunavut tax before credits			260	A13
Deduct:				
Nunavut political contribution tax credit		725		
Contribution	899			
Nunavut foreign tax credit (from Schedule 21)		730		
Northwest Territories investment tax credit on investments made before April 1, 1999 (from Schedule 460)		734		
Nunavut investment tax credit (from Schedule 480)		735		
	Subtotal			B13
Total Nunavut tax payable before refundable credits (amount A13 **minus** amount B13) (if negative, enter "0")				C13
Deduct:				
Nunavut business training tax credit (from Schedule 490)			740	D13
Net Nunavut tax payable (amount C13 **minus** amount D13)			264	E13

(if a credit, enter amount in brackets) 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	92,494

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 on page 8 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 on page 8 of the T2 return.

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CAPITAL COST ALLOWANCE

Schedule 8

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 200		2 UCC at start of year 201	3 Cost of additions in the year 203	4 Net adjustments 205	5 Proceeds of dispositions in the year 207	7 Adjustment for additions (1/2 x (col 3 - 5)) 211	8 Base amount for CCA	9 Rate % 212	10 Recapture of CCA 213	11 Terminal loss 215	12 CCA for the year (col 8 x 9 or a lower amount) 217	13 UCC at the end of the year 220
1	1	851,817					851,817	4			34,073	817,744
2	1	8,203,448	57,097			28,549	8,231,996	4			329,280	7,931,265
3	10	322,917	364,617			182,309	505,225	30			151,568	535,966
4	10	7,140					7,140	30			2,142	4,998
5	45	2,458					2,458	45			1,106	1,352
6	47	3,463,591	1,118,387	(107,268)		559,194	3,915,516	8			313,241	4,161,469
7	50	2,520					2,520	55			1,386	1,134
8	8	39,749	13,957			6,979	46,727	20			9,345	44,361
9	6	11,129					11,129	10			1,113	10,016
10	12		47,744			23,872	23,872	100			23,872	23,872
11	52		8,308				8,308	100			8,308	
								NA				
Totals		12,904,769	1,610,110	(107,268)		800,903	13,606,708				875,434	13,532,177

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CAPITAL COST ALLOWANCE

Schedule 8

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 200		2 UCC at start of year 201	3 Cost of additions in the year 203	4 Net adjustments 205	5 Proceeds of dispositions in the year 207	7 Adjustment for additions (1/2 x (col 3 - 5)) 211	8 Base amount for CCA	9 Rate % 212	10 Recapture of CCA 213	11 Terminal loss 215	12 CCA for the year (col 8 x 9 or a lower amount) 217	13 UCC at the end of the year 220
1	1	851,817					851,817	4			34,073	817,744
2	1	8,203,448	57,097			28,549	8,231,996	4			329,280	7,931,265
3	10	322,917	364,617			182,309	505,225	30			151,568	535,966
4	10	7,140					7,140	30			2,142	4,998
5	45	2,458					2,458	45			1,106	1,352
6	47	3,463,591	1,118,387	(107,268)		559,194	3,915,516	8			313,241	4,161,469
7	50	2,520					2,520	55			1,386	1,134
8	8	39,749	13,957			6,979	46,727	20			9,345	44,361
9	6	11,129					11,129	10			1,113	10,016
10	12		47,744			23,872	23,872	100			23,872	23,872
11	52		8,308				8,308	100			8,308	
								NA				
Totals		12,904,769	1,610,110	(107,268)		800,903	13,606,708				875,434	13,532,177

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Schedule 23
Code 0901

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, including 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

Enter the calendar year to which the agreement applies 050 2010

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 Association code 300
1	Lakefront Utilities Inc.	86512 5231 RC 0001	1
2	Town of Cobourg Holdings Inc.	86511 7832 RC 0001	1
3	Lakefront Utilities Services Inc	86906 0327 RC 0001	3
4	Lakefront Generation Inc.	82428 6942 RC 0001	1
5	Lakefront Lighting Inc.	85700 1424 RC 0001	1
6	Cobourg Networks Inc	86512 5033 RC 0001	1

Allocate business limit using: ☒ % ☐ $

	Taxation year Start	Taxation year End	4 Business limit for the year (before the allocation) $	Allocating business limit: 5 Percentage of the business limit (%) 350	6 Business limit allocated * $ 400	7 Gross Part I.3 tax for business limit reduction
1	2010/01/01	2010/12/31	500,000	100.000	500,000	16,006
2	2010/01/01	2010/12/31	500,000			
3	2010/01/01	2010/12/31	500,000			
4	2010/01/01	2010/12/31	500,000			
5	2010/01/01	2010/12/31	500,000			
6	2010/01/01	2010/12/31	500,000			
TOTALS				100.000	A 500,000	16,006

If the taxation year of the corporation filing this form is less than 51 weeks, enter the prorated business limit in this box. $ 500,000

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AGREEMENT AMONG ASSOCIATED CCPCs TO ALLOCATE THE BUSINESS LIMIT

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.

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SCHEDULE 33
Code 1001

TAXABLE CAPITAL EMPLOYED IN CANADA – LARGE CORPORATIONS

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act and the Income Tax Regulations*.
- Subsection 181(1) defines the terms "financial institution," "long-term debt," and "reserves."
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If you are filing a provincial capital tax return with your *T2 Corporation Income Tax Return*, also file a completed Schedule 33 with the return no later than six months from the end of the tax year.
- This schedule may contain changes that had not yet become law at the time of publishing.

If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, "Taxable capital employed in Canada."

Part 1 - Capital

Add the following amounts at the end of the year:				
Reserves that have not been deducted in computing income for the year under Part I	101			
Capital stock (or members' contributions if incorporated without share capital)	103	5,293,376		
Retained earnings	104	2,748,411		
Contributed surplus	105			
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108	10,547,658		
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109			
Any dividends declared but not paid by the corporation before the end of the year	110			
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111	371,446		
Proportion of the amount, if any, by which the total of all amounts (see note below) for the partnership of which the corporation is a member at the end of the year exceeds the amount of the partnership's deferred unrealized foreign exchange losses	112			
Subtotal		18,960,891	18,960,891	A
Deduct the following amounts:				
Deferred tax debit balance at the end of the year	121			
Any deficit deducted in computing its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122			
Any amount deducted under subsection 135(1) in computing income under Part I for the year, as long as the amount may reasonably be regarded as being included in any of lines 101 to 112 above	123			
The amount of deferred unrealized foreign exchange losses at the end of the year	124			
Subtotal				B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")			190 18,960,891	

Note: Lines 101, 107, 108, 109, 111, and 112 are determined as follows:
- If the partnership is a member of another partnership (tiered partnerships), include the amounts of the partnership and tiered partnerships.
- Amounts for the partnership and tiered partnerships are those that would be determined for lines 101, 107, 108, 109, 111, and 112 as if they apply in the same way that they apply to corporations.
- Do not include amounts owing to the member or to other corporations that are members of the partnership.
- Amounts are determined at the end of the last fiscal period of the partnership ending in the year of the corporation.
- The proportion of the total amounts is determined by the corporation's share of the partnership's income or loss for the fiscal period of the partnership.

Part 2 - Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend receivable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim, or similar obligation of, a partnership all of the members of which, throughout the year, were other corporations (other than financial institutions) that were not exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)]	406	
An interest in a partnership	407	
Investment allowance for the year (add lines 401 to 407)	490	

Notes:

1. Where the corporation has an interest in a partnership or in tiered partnerships, consider the following:
   - the investment allowance of a partnership is deemed to be the amount calculated at line 490 above, at the end of its fiscal period, as if it was a corporation;
   - the total of the carrying value of each asset of the partnership described in the above lines is for its last fiscal period ending at or before the end of the corporation's tax year; and
   - the carrying value of a partnership member's interest at the end of the year is its specified proportion [as defined in subsection 248(1)] of the partnership's investment allowance.
2. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)].
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation, according to subsection 181.2(6).

Part 3 - Taxable capital

Capital for the year (line 190)		18,960,891	C
Deduct: Investment allowance for the year (line 490)			D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	18,960,891	

Part 4 - Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 18,960,891 x (Taxable income earned in Canada / Taxable income) 610 927,621 / 927,621 = **Taxable capital employed in Canada** 690 18,960,891

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada — 701

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada — 711

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada — 712

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) — 713

Total deductions (add lines 711, 712, and 713) — E

Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0") — 790

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 - Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (line 690 or 790, whichever applies)	18,960,891	F
Deduct:	10,000,000	G
Excess (amount F **minus** amount G) (if negative, enter "0")	8,960,891	H
Calculation for purposes of the small business deduction (amount H x 0.00225)	20,162	I

Enter this amount at line 415 of the T2 return.

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SHAREHOLDER INFORMATION

Schedule 50

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	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 (If a trust number is not available, enter "NA") * 350	Percentage common shares 400	Percentage preferred shares 500
1	Town of Cobourg Holdings Inc.	NR			100.000	
		RC				

* For a taxation year commencing before January 1, 2004, if the shareholder is a trust, enter NR at field 200 or NA at field 300. Do not enter a trust number in field 350.

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SCHEDULE 53
Code 0901

GENERAL RATE INCOME POOL (GRIP) CALCULATION

- 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.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year				100	2,671,759 A
Taxable income for the year (DICs enter "0")*			110	927,621 B	
Income for the credit union deduction* (amount E in Part 3 of Schedule 17)	120	0			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less*	130	0			
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income *	140	0			
Subtotal (**add** lines 120, 130 and 140)		0		0 C	
Income taxable at the general corporate rate (line B **minus** line C)			150	927,621	
After-tax income (line 150 x general rate factor for the tax year ** 0.6900)					190 640,058 D
Eligible dividends received in the tax year			200	0	
Dividends deductible under section 113 received in the tax year			210	0	
Subtotal (**add** lines 200 and 210)				0	0 E
GRIP addition:					
Becoming a CCPC (line PP from Part 4)			220	0	
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)			230	0	
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)			240	0	
Subtotal (**add** lines 220, 230, and 240)				0	290 0 F
Subtotal (**add** lines A, D, E, and F)					3,311,817 G
Eligible dividends paid in the previous tax year			300	0	
Excessive eligible dividend designations made in the previous tax year			310	0	
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310. Subtotal (line 300 **minus** line 310)				0	0 H
GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative)					490 3,311,817
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)					560 0
GRIP at the end of the tax year (line 490 minus line 560)					590 3,311,817

Enter this amount on line 160 on Schedule 55.

* 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 the total of 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 on page 5 for tax years that straddle these dates.

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GENERAL RATE INCOME POOL (GRIP) CALCULATION

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560 of page 1.

First previous tax year

Taxable income before specified future tax consequences from the current tax year		0 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)	0 K1			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 L1			
Aggregate investment income (line 440 of the T2 return)	0 M1			
Subtotal (**add** lines K1, L1, and M1)	0	0 N1		
Subtotal (line J1 **minus** line N1) (if negative, enter "0")		0	0 O1	
Taxable income after specified future tax consequences		0 P1		
Enter the following amounts after specified future tax consequences:				
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	0 Q1			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 R1			
Aggregate investment income (line 440 of the T2 return)	0 S1			
Subtotal (**add** lines Q1, R1, and S1)	0	0 T1		
Subtotal (line P1 **minus** line T1) (if negative, enter "0")		0	0 U1	
Subtotal (line O1 **minus** line U1) (if negative, enter "0")			0 V1	
GRIP adjustment for specified future tax consequences to first previous tax year (line V1 **multiplied by** the general rate factor for the tax year 0.6800)			500	0

Second previous tax year

Taxable income before specified future tax consequences from the current tax year		0 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)	0 K2			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 L2			
Aggregate investment income (line 440 of the T2 return)	0 M2			
Subtotal (**add** lines K2, L2, and M2)	0	0 N2		
Subtotal (line J2 **minus** line N2) (if negative, enter "0")		0	0 O2	
Taxable income after specified future tax consequences		0 P2		
Enter the following amounts after specified future tax consequences:				
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	0 Q2			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 R2			
Aggregate investment income (line 440 of the T2 return)	0 S2			

1

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GENERAL RATE INCOME POOL (GRIP) CALCULATION

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year

Taxable income before specified future tax consequences from the current tax year		0 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)	0 K3			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 L3			
Aggregate investment income (line 440 of the T2 return)	0 M3			
Subtotal (**add** lines K3, L3, and M3)	0 ▶	0 N3		
Subtotal (line J3 **minus** line N3) (if negative, enter "0")		0 ▶	0 O3	
Taxable income after specified future tax consequences		0 P3		
Enter the following amounts after specified future tax consequences:				
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	0 Q3			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 R3			
Aggregate investment income (line 440 of the T2 return)	0 S3			
Subtotal (**add** lines Q3, R3, and S3)	0 ▶	0 T3		
Subtotal (line P3 **minus** line T3) (if negative, enter "0")		0 ▶	0 U3	
Subtotal (line O3 **minus** line U3) (if negative, enter "0")			0 V3	
GRIP adjustment for specified future tax consequences to third previous tax year (line V3 **multiplied by** the general rate factor for the tax year 0.6800)			540	0
Total GRIP adjustment for specified future tax consequences to previous tax years: (**add** lines 500, 520, and 540) (if negative, enter "0")				0 W

Enter amount W on line 560 on page 1.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year			0 AA
Eligible dividends paid by the corporation in its last tax year	0 BB		
Excessive eligible dividend designations made by the corporation in its last tax year	0 CC		
Subtotal (line BB **minus** line CC)	0 ▶		0 DD
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year) (line AA **minus** line DD)			0 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 on page 1 for post-amalgamation; or
- line 240 on page 1 for post-wind-up.

2

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GENERAL RATE INCOME POOL (GRIP) CALCULATION

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year		0 FF
The corporation's money on hand immediately before the end of its previous/last tax year		0 GG
Unused and unexpired losses at the end of the corporation's previous tax year		
Non-capital losses	0	
Net capital losses	0	
Farm losses	0	
Restricted farm losses	0	
Limited partnership losses	0	
Subtotal	0 ▶	0 HH
Subtotal (**add** lines FF, GG, and HH)		0 II
All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year	0 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	0 KK	
All the corporation's reserves deducted in its previous/last tax year	0 LL	
The corporation's capital dividend account immediately before the end of its previous/last tax year	0 MM	
The corporation's low rate income pool immediately before the end of its previous/last tax year	0 NN	
Subtotal (**add** lines JJ, KK, LL, MM, and NN)	0 ▶	0 OO
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0")		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 on page 1 for a corporation becoming a CCPC;
- line 230 on page 1 for post-amalgamation; or
- line 240 on page 1 for post-wind-up.

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GENERAL RATE INCOME POOL (GRIP) CALCULATION

Part 5 – General Rate Factor for the Tax Year

Complete this part to calculate the general rate factor for the tax year. Calculate your results to 4 decimal places.

0.68	x	number of days in the tax year before January 1, 2010 / number of days in the tax year	0 / 365	=	0.0000	QQ
0.69	x	number of days in the tax year in 2010 / number of days in the tax year	365 / 365	=	0.6900	RR
0.70	x	number of days in the tax year in 2011 / number of days in the tax year	0 / 365	=	0.0000	SS
0.72	x	number of days in the tax year after December 31, 2011 / number of days in the tax year	0 / 365	=	0.0000	TT

General Rate Factor for the tax year (total of lines QQ to TT) 0.6900 UU

1

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BALANCE SHEET INFORMATION

Schedule 100

Assets	Code	Current year	Prior year
Cash and deposits	1000	3,651,326	2,141,428
Accounts Receivable	1060	1,842,053	1,586,245
Taxes receivable	1066	65,155	222,900
Inventories	1120	239,490	238,012
Other current assets	1480	3,442,157	2,817,654
Future income taxes	1481		555,000
Taxes recoverable / refundable	1483	515,000	
Prepaid expenses	1484	50,110	46,588
Land	1600	219,284	219,284
Buildings	1680	919,216	862,119
Accumulated amortization of buildings	1681	(118,783)	(98,905)
Other tangible capital assets	1900	17,179,895	16,675,049
Accumulated amortization of other tangible capital assets	1901	(7,293,536)	(6,804,238)
Other deferred items / charges	2424	1,347,373	2,190,895
Total assets	2599	22,058,740	20,652,031

Liabilities	Code	Current year	Prior year
Bank overdraft	2600		
Amounts payable and accrued liabilities	2620	2,828,905	3,328,973
Deposits received	2961	293,453	165,000
Long term debt	3140	3,547,658	1,653,000
Due to related parties	3300	7,000,000	7,000,000
Other long term liabilities	3320	77,994	209,063
General provisions / reserves	3325	268,943	264,156
Total liabilities	3499	14,016,953	12,620,192

Equity	Code	Current year	Prior year
Common shares	3500	5,293,376	5,293,376
Retained earnings / deficit	3600	2,748,411	2,738,463
Total equity	3620	8,041,787	8,031,839
Total liabilities and equity	3640	22,058,740	20,652,031

Retained earnings	Code	Current year	Prior year
Retained earnings/deficit-start	3660	2,738,463	2,041,773
Net income / loss	3680	609,948	751,690
Cash dividends	3701	(600,000)	(600,000)
Other items affecting retained earnings	3740		545,000
Total retained earnings	3849	2,748,411	2,738,463

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INCOME STATEMENT INFORMATION

Schedule 125

Details

Operating name, if different from the corporations' legal name
0001

Description of operation, if filing multiple Schedules 125
0002

Revenue	Code	Current year	Prior year
Trade sales of goods and services	8000	4,059,895	4,388,627
Total sales of goods and services	8089	4,059,895	4,388,627
Realized gains / losses on disposal of assets	8210		10,178
Other revenue	8230	359,867	384,131
Total revenue	8299	4,419,762	4,782,936

Cost of sales	Code	Current year	Prior year
Opening inventory	8300		
Cost of sales	8518		
Gross profit / loss (item 8089 - item 8518)	8519	4,059,895	4,388,627

Operating expenses	Code	Current year	Prior year
Amortization of tangible assets	8670	894,073	893,443
Interest and bank charges	8710	73,759	79,219
Interest on long term debt	8714	507,500	507,950
Collection and credit costs	8717	425,479	407,717
Other expenses	9270		296,686
Delivery, freight and express	9275	641,133	645,289
General and administrative expenses	9284	973,623	855,701
Total operating expenses	9367	3,515,567	3,686,005
Total expenses	9368	3,515,567	3,686,005
Net non-farming income	9369	904,195	1,096,931

Farming revenue	Code	Current year	Prior year
Grains and oilseeds	9370		
Total farm revenue	9659		

Farming expenses	Code	Current year	Prior year
Crop expenses	9660		
Total farm expenses	9898		
Net farm income	9899		
Net income / loss before taxes and extraordinary items	9970	904,195	1,096,931

Summary

Complete this section if only one Schedule 125 is filed, Schedule 140 is used to summarize the information from multiple Schedules 125.

Extraordinary items	9975	-		-
Legal settlements	9976	-		-
Unrealized gains / losses	9980	+		+
Unusual items	9985	-		-
Current income taxes	9990	-	254,247	- 355,241
Future income tax provision	9995	-	40,000	- (10,000)
Total - Other comprehensive income	9998	+		+
Net income / loss after taxes and extraordinary items	9999	=	609,948	= 751,690

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Schedule 141
Code 0801

NOTES CHECKLIST

- 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) for Corporations 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 preparing or reporting 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 with 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 102 to 107 below:

Are any values presented at other than cost?	**102** 1 Yes [ ] 2 No [X]
Has there been a change in accounting policies since the last return?	**103** 1 Yes [ ] 2 No [X]
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 mentioned in the notes?	**106** 1 Yes [ ] 2 No [X]
Is information regarding commitments mentioned in the notes?	**107** 1 Yes [ ] 2 No [X]

Does the corporation have investments in joint venture(s) or partnership(s)? **108** 1 Yes [ ] 2 No [X]

If **yes**, complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)? **109** 1 Yes [ ] 2 No [ ]

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ONTARIO CORPORATION TAX CALCULATION

SCHEDULE 500

- 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.
- References to subsections and paragraphs are from the federal *Income Tax Act*.
- 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	181 / 365	x	14.00000 %	=	6.94247 % A1
Number of days in the tax year after June 30, 2010 and before July 1, 2011 / Number of days in the tax year	184 / 365	x	12.00000 %	=	6.04932 % A2
Number of days in the tax year after June 30, 2011 and before July 1, 2012 / Number of days in the tax year	___ / 365	x	11.50000 %	=	% A3
Number of days in the tax year after June 30, 2012 and before July 1, 2013 / Number of days in the tax year	___ / 365	x	11.00000 %	=	% A4
Number of days in the tax year after June 30, 2013 / Number of days in the tax year	___ / 365	x	10.00000 %	=	% A5

Ontario basic rate of tax for the year (total of rates A1 to A5) 12.99179 ▶ 12.99179 % A6

Part 2 - Calculation of Ontario basic income tax

Ontario taxable income * 927,621 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A6 from Part 1) 120,515 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 on page 8 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, from page 3 of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

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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)			927,621	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)			927,621	2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)	500,000 x	500,000 / 500,000 =	500,000	3
Enter the least of amounts 1, 2, and 3			500,000	D
Ontario domestic factor: Ontario taxable income * / taxable income earned in all provinces and territories **		927,621 / 927,621 =	1.00000	E
Ontario small business income (amount D **multiplied** by amount E)			500,000	F

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	181 / 365 x	8.50000 % =	4.21507	% G1
Number of days in the tax year after June 30, 2010 and before July 1, 2011 / Number of days in the tax year	184 / 365 x	7.50000 % =	3.78082	% G2
Number of days in the tax year after June 30, 2011 and before July 1, 2012 / Number of days in the tax year	/ 365 x	7.00000 % =		% G3
Number of days in the tax year after June 30, 2012 and before July 1, 2013 / Number of days in the tax year	/ 365 x	6.50000 % =		% G4
Number of days in the tax year after June 30, 2013 / Number of days in the tax year	/ 365 x	5.50000 % =		% G5
OSBD rate for the year (total of rates G1 to G5)			7.99589	% G6

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G6) 39,979 H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia, and Newfoundland and Labrador.

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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: You do not need to complete this part if the corporation's tax year begins after June 30, 2010.

Adjusted taxable income *	927,621 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)	927,621	▶	927,621 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)			427,621 L

Small business surtax rate for the year:

Number of days in the tax year before July 1, 2010 / Number of days in the tax year: 181 / 365 x 4.25000 % = 2.10753 % M

Note: For days in the tax year after June 30, 2010, the small business surtax rate is reduced to 0%.

Multiply: Amount L x % on line M = 9,012 N

Amount N x Ontario small business income (amount F from Part 3) / 500,000: 500,000 / 500,000 = 9,012 O

Surtax re Ontario small business deduction: lesser of amount O and OSBD (amount H in Part 3) 9,012 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.

Amount D in Part 3: 500,000 Q

Surtax payable (amount P from Part 4) 9,012 / (1.00000 x 7.99589 %) = 112,708 R

Ontario domestic factor (amount E from Part 3) / OSBD rate (rate G6 from Part 3)

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") 387,292 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.

Client: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2010/12/31 Printed: 2011/06/02 12:29

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 in 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)	7.99589 %		
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 Z on line 410 on Schedule 5.

Client: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2010/12/31 Printed: 2011/06/02 12:29

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 501
Code 1001

ONTARIO ADJUSTED TAXABLE INCOME OF ASSOCIATED CORPORATIONS TO DETERMINE SURTAX RE ONTARIO SMALL BUSINESS DEDUCTION

- For use by Canadian-controlled private corporations (CCPCs) to report the adjusted taxable income of all corporations (Canadian and foreign) with which the filing corporation was associated at any time during the tax year.
- Include the adjusted taxable income for the tax year of the associated corporation that ends at or before the date of the filing corporation's tax year-end.
- File this schedule with the *T2 Corporation Income Tax Return*.

	Names of associated corporations * 100	Business number of associated corporations ** 200	Tax year-end 300	Adjusted taxable income (if loss, enter "0") *** 400
1	Town of Cobourg Holdings Inc.	86511 7832 RC 0001	2010/12/31	0
2	Lakefront Generation Inc.	82428 6942 RC 0001	2010/12/31	0
3	Lakefront Lighting Inc.	85700 1424 RC 0001	2010/12/31	0
4	Cobourg Networks Inc	86512 5033 RC 0001	2010/12/31	0
			Total 500	

Enter the total adjusted taxable income from line 500 on line J in Part 4 of Schedule 500, *Ontario Corporation Tax Calculation*.

* Subsection 256(2) of the federal *Income Tax Act* may deem the filing corporation to be associated with another corporation, because both corporations are associated with a third corporation. If so, do not list the other corporation, nor the third corporation if it is not a CCPC or has elected under subsection 256(2) of the federal Act not to be associated for purposes of section 125 of the federal Act.

** Enter "NR" if a corporation is not registered.

*** **Rules for adjusted taxable income:**

- If the associated corporation's tax year ends after December 31, 2008, its adjusted taxable income is equal to its taxable income or taxable income earned in Canada **plus** its adjusted Crown royalties **minus** its notional resource allowance for the year.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's adjusted taxable income by 365 and **divide** by the number of days in the associated corporation's tax year.
- If the associated corporation has two or more tax years ending in the filing corporation's tax year, enter the last tax year-end date on line 300 and, for the entry on line 400, **multiply** the sum of the adjusted taxable income for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.

Client: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2010/12/31 Printed: 2011/06/02 12:29

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 515
Code 0902

ONTARIO CAPITAL TAX ON OTHER THAN FINANCIAL INSTITUTIONS

- Complete this schedule for a corporation with a permanent establishment in Ontario at any time in the tax year and that is a corporation other than a financial institution. The Ontario capital tax on other than financial institutions is levied under section 64 of the *Taxation Act, 2007* (Ontario).
- The Ontario capital tax is eliminated effective July 1, 2010. You do not have to complete this schedule if the corporation's tax year begins after June 30, 2010. For businesses mainly engaged in qualifying manufacturing and resource activities in Ontario, the capital tax is eliminated effective January 1, 2007.
- To complete this schedule, you have to complete Schedule 33, *Part I.3 Tax on Large Corporations* (renamed *Taxable Capital Employed in Canada – Large Corporations* for 2010 and later tax years). File completed copies of both schedules with the *T2 Corporation Income Tax Return* within six months of the end of the tax year.
- A corporation is exempt from Ontario capital tax if it was one of the following:
  1) a corporation that is liable to the special additional tax according to section 74 of the *Corporations Tax Act* (Ontario);
  2) a credit union;
  3) a deposit insurance corporation according to section 137.1 of the federal *Income Tax Act*;
  4) a family farm corporation for the year as defined by subsection 64(3) of the *Taxation Act, 2007* (Ontario), other than a corporation for which a determination has been made under subsection 31(2) of the federal Act;
  5) a family fishing corporation, as defined by subsection 64(3) of the *Taxation Act, 2007* (Ontario); or
  6) a corporation exempt from income tax according to section 149 of the federal Act.

Part 1 – Taxable capital of a corporation resident in Canada other than a financial institution

Amount A from Part 1 of Schedule 33	100	18,960,891	
Add:			
Accumulated other comprehensive income at the end of the year	105		
Subtotal		18,960,891	▶ 18,960,891 A
Deduct:			
Amount B from Part 1 of Schedule 33	110		
Amount on line 490 from Part 2 of Schedule 33	115		
Subtotal			▶ B
Taxable capital (amount A **minus** amount B) (if negative, enter "0")		120	18,960,891

Part 2 – Capital deduction

Complete this part only if the corporation is associated.

Are you electing under subsection 83(2) of the *Taxation Act, 2007* (Ontario)? **190** 1 Yes ☐ 2 No ☒

If you answered **no** to the question at line 190, complete line 220. If you answered **yes** to the question at line 190, complete line 305 by using Schedule 516, *Capital Deduction Election of Associated Group for the Allocation of Net Deduction*, to calculate the amount to be entered on line 300.

Taxable capital (from line 120) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (from line 790 in Part 4 of Schedule 33)	200	18,960,891	x $15,000,000 = **Capital deduction**	220	15,000,000
Taxable capital or taxable capital employed in Canada of every corporation with a permanent establishment in Canada and associated for the last tax year *	210	18,960,891			

* This amount includes the filing corporation's taxable capital or taxable capital employed in Canada. Do not include an amount from a financial institution or corporation that is exempt from capital tax under Division E of the *Taxation Act*, 2007 (Ontario) or Part III of the *Corporations Tax Act* (Ontario).

Allocation of net deduction (from line 600 for the filing corporation from Schedule 516)	300	= **Capital deduction**	305
Ontario allocation factor (OAF) (amount I in Part 3)			

T2 SCH 515 E (10) Version 2010.4.3 GP41 - **RETAIN ON FILE. DO NOT SUBMIT TO THE CRA**

Canada

Client: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2010/12/31 Printed: 2011/06/02 12:29

Part 3 – Ontario capital tax payable

Taxable capital (enter amount from line 120 in Part 1) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (enter amount from line 790 in Part 4 of Schedule 33), whichever applies **320** 18,960,891

Deduct:
Capital deduction (Enter $15,000,000 if the corporation is not associated. Otherwise, enter the amount from line 220 or line 305, whichever applies, from Part 2) 15,000,000 B

Net amount (line 320 **minus** amount B) (if negative, enter "0") 3,960,891 C

Note: For days in the tax year after June 30, 2010, the Ontario capital tax rate is 0%.

Amount C 3,960,891 x (Number of days in the tax year before January 1, 2010 / Number of days in the tax year) ____ / 365 X 0.00225 = ____ D

Amount C 3,960,891 x (Number of days in the tax year after December 31, 2009 and before July 1, 2010 / Number of days in the tax year) 181 / 365 X 0.00150 = 2,946 E

Subtotal (amount D **plus** amount E) 2,946 F

Amount F 2,946 x OAF (amount on line I) 1.00000 = 2,946 G

Amount G 2,946 x (Number of days in the tax year * / 365) 365 / 365 = 2,946 H

Deduct:
Capital tax credit for manufacturers (enter amount J from Part 4). **350** ____

Ontario capital tax payable (amount H **minus** line 350) (if negative, enter "0") **400** 2,946
Enter amount from line 400 on line 282 of Schedule 5, *Tax Calculation Supplementary - Corporations.*

* Enter either 365 if there are at least 51 weeks in the tax year, or the number of days in the year, whichever applies.

Calculation of the Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario", enter "1" on line I.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple", complete the following calculation and enter the result on line I:

Ontario taxable income ** / Taxable income *** = ____

Ontario allocation factor 1.00000 I

** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*** Enter the taxable income amount from line 360 or line Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Capital tax credit for manufacturers

Ontario manufacturing labour cost* **405** ____ / Ontario labour cost** **410** x 100 = **420** ____ %

If the percentage on line 420 is 20% or less, enter "0" on line J.
If the percentage on line 420 is at least 50%, enter amount H from Part 3 on line J.
If the percentage on line 420 is more than 20% but less than 50%, complete the following calculation and enter the result on line J:

(percentage from line 420) - 20% / 30% ____ % x Amount H from Part 3 = 2,946 / 30%

Capital tax credit for manufacturers ____ J
Enter amount J on line 350 in Part 3.

* As defined in subsection 83.1(4) of the *Taxation Act, 2007* (Ontario)
** As defined in subsection 83.1(5) of the *Taxation Act, 2007* (Ontario)

1

S515Supp

Taxable capital of associated corporations other than financial institutions

- Complete this worksheet to calculate taxable capital or taxable capital employed in Canada of every corporation with a permanent establishment in Canada and associated for the last tax year.

Name of each associated corporation	Business number	Taxable capital or taxable capital employed in Canada
Lakefront Utilities Inc.	86512 5231 RC 0001	18,960,891
	RC	
Taxable capital or taxable capital employed in Canada of every corporation with a permanent establishment in Canada and associated for the last tax year (Enter on line 210 in Part 2 of Schedule 515)		18,960,891

1

Client: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2010/12/31 Printed: 2011/06/02 12:29

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546
Code 0902

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

- 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)		
Lakefront Utilities Inc.		
Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent	**120** Ontario Corporation No.
Ontario	2000/05/01	1412420

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
207	Division Street		
240 Additional address information if applicable (line 220 must be completed first)			
250 Municipality (e.g., city, town)	**260** Province	**270** Country	**280** Postal code
Cobourg	ON	CA	K9A 4L3

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 Cunningham (Last name) **451** Stewart (First name) **454** _____ (Middle name(s))

460 [2] Please enter one of the following numbers in this box for the above-named person: enter **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.

T2 SCH 546 E (10) Version 2010 4.3 GP41 - RETAIN ON FILE. DO NOT SUBMIT TO THE CRA

Canada

Client: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2010/12/31 Printed: 2011/06/02 12:29

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 preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communication with the corporation. This may be different from line 990 on the T2 return.

Canada

Client: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2010/12/31 Printed: 2011/06/02 12:29

Instalments

Federal tax instalments

This worksheet is provided for estimation purposes only and should not be relied upon solely to schedule installment payments. Always verify installment payment requirements according to the latest T7B-CORP as well as any schedule of installment payments issued by the CRA and/or Provincial authority upon assessment.

Instalment base

	Estimate for current year	First instalment base	Second instalment base
Year-end	2011/12/31	2010/12/31	2009/12/31
Taxable income		927,621	1,129,302
Base amount of Part I tax		352,496	429,135
Corporate surtax			
Recapture of investment tax credit			
Refundable tax on CCPC's investment income			
Small business deduction			15,776
Federal tax abatement		92,762	112,930
Manufacturing and processing profits deduction			
Foreign tax credits			
Tax reductions		92,762	93,285
Political contribution tax credit			
Investment tax credit			
Other credits			
Part I tax payable		166,972	207,144
Part I.3 tax payable			
Part VI tax payable			
Part VI.1 tax payable			
Part XIII.1 tax payable			
Net provincial or territorial tax payable (excluding Ontario)			
Ontario - Single administration			
Income tax payable		89,548	146,167
Corporate minimum tax payable			
Capital tax payable		2,946	4,756
Ontario special additional tax on life insurance corporations			
Total tax payable		259,466	358,067
Days in taxation year	365	365	365
Tax payable adjusted for short taxation years		259,466	358,067
Estimated credits for the current year:			
Investment tax credit refund			
Dividend refund			
Other federal credits		4	
Other provincial credits			
Total estimated credits		4	
Instalment base (excludes federal and/or provincial component on or below the $3,000 threshold)		259,462	358,067
Monthly payment		21,622	29,839

Instalment payment options

- [ ] 1. based on estimated taxes for the current year
- [x] 2. based on the first instalment base
- [ ] 3. based on the first and second instalment base
- [ ] 4. instalments are not required

Does the corporation qualify for quarterly Instalments*? [ ] Yes [ ] 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

Instalment payments

Date	Instalments required	Instalments paid	Instalments payable
2011/01/31	21,622		
2011/02/28	21,622		
2011/03/31	21,622		
2011/04/30	21,622		
2011/05/31	21,622		
2011/06/30	21,622		129,732
2011/07/31	21,622		21,622

1

Client: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2010/12/31 Printed: 2011/06/02 12:29

Instalments

Federal tax instalments

Date	Instalments required	Instalments paid	Instalments payable
2011/08/31	21,622		21,622
2011/09/30	21,622		21,622
2011/10/31	21,622		21,622
2011/11/30	21,622		21,622
2011/12/31	21,622		21,622
Total	259,464		259,464

APPENDIX D ACTUARIAL VALUATION REPORT

Dion Durrell
Actuaries and Consultants

Dion, Durrell + Associates Inc.
250 Yonge Street, Suite 2900
Toronto, Ontario, Canada M5B 2L7
dion-durrell.com

T 416 408 2626
F 416 408 3721

July 15, 2010

BY MAIL

Mr. Stewart Cunningham
Treasurer
Lakefront Utility Services Inc.
207 Division Street
Cobourg, ON K9A 4L3

Dear Mr. Cunningham:

Re: Lakefront Utility Services Inc. Actuarial Valuation Report as at January 1, 2009: Post-Retirement Non-Pension Benefit Plan

As requested, attached is our actuarial valuation report as at January 1, 2009 for the above-captioned plan. The valuation report provides details of the calculation of the FY 2009 benefit expense of approximately $45,000 for post-retirement non-pension benefits.

In addition, we have attached accounting worksheets summarizing the calculation of the December 31, 2009 Accrued Benefit Obligation (ABO) and projected Benefit Expense figures for FY 2010.

The December 31, 2009 ABO calculations are based on the same methodology, data, and assumptions as used in our January 1, 2009 valuation report with one exception, namely that a discount rate assumption of 5.0% per annum was used at December 31, 2009 to reflect Lakefront's best estimate assumptions for yields on high quality debt instruments.

If you have any questions regarding the valuation report or the attached accounting schedules, please do not hesitate to call.

Yours truly,

Stanley Caravaggio, FSA FCIA
Consulting Actuary
[E-mail: stanleyc@dion-durrell.com]
[Telephone: 416.408.5306]

Connie Cheung
Actuarial Analyst
[E-mail: conniec@dion-durrell.com]
[Telephone: 416.408.5333]

SC/CC:jb
Encls.

Cunningham\S 1009 Lakefront_2009 val report final.doc

7/15/2010

Lakefront Utility Services Inc.

Total

ESTIMATED BENEFIT EXPENSE (CICA 3461)

Final

	Calendar Year 2009	Projected Calendar Year 2010
Discount Rate - January 1	6.00%	5.00%
Discount Rate - December 31	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*

C. Calculation of Component Items

Calculation of the Service Cost		
- Current service cost	14,070	14,774
Interest on Benefits		
- ABO at January 1	505,443	586,896
- Current service cost	14,070	14,774
- Benefit payments	(11,549)	(12,263)
- Accrued benefits	507,964	588,406
- Interest	30,478	29,420
Expected Interest on Assets		
- Assets at January 1	-	-
- Funding	11,549	12,263
- Benefit payments	(11,549)	(12,263)
- Expected assets	-	-
- Interest	-	-
Expected ABO as at December 31		
- ABO at January 1	505,443	586,896
- Current service cost	14,070	14,774
- Interest on benefits	30,478	29,420
- Benefit payments	(23,098)	(24,526)
- Expected ABO at December 31	526,893	605,563
Expected Assets as at December 31		
- Assets at January 1	-	-
- Funding	23,098	24,526
- Interest on assets	-	-
- Benefit payments	(23,098)	(24,526)
- Expected Assets at December 31	-	-

Projected calendar year 2010 results are provided for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2009.

7/15/2010

Lakefront Utility Services Inc.

Total

ESTIMATED BENEFIT EXPENSE (CICA 3461)

Final

	Calendar Year 2009	Projected Calendar Year 2010
Discount Rate - January 1	6.00%	5.00%
Discount Rate - December 31	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*

D. Actuarial (Gain)/Loss

(Gain)/Loss on ABO as at January 1		
- Prepaid Liability as at January 1	536,375	557,740
- Unrecognized Actuarial (Gain)/Loss	-	28,156
- Expected ABO	536,375	585,896
- Actual ABO	505,443	585,896
- (Gain)/Loss on ABO	(30,932)	-
(Gain)/Loss on assets as at January 1		
- Expected assets	-	-
- Actual assets	-	-
- (Gain)/Loss on assets	-	-
Total (Gain)/Loss as at January 1	(30,932)	28,156
10% of ABO as at January 1	50,544	58,590
Total (Gain)/Loss to be amortized	-	-
Expected average remaining service life (years)	6	5
Minimum Amortization for current year	-	-
Actual Amortization for current year **	(85)	-

(Gain)/Loss on ABO at December 31 due to change in discount rate assumption	
- Expected ABO - December 31	526,893
- Actual ABO - December 31	585,896
- (Gain)/Loss on ABO at December 31	59,003
Unamortized (Gain)/Loss	28,156

** Based on the application of the corridor method for amortization of actuarial gains and losses as described in CICA 3461 .

Projected calendar year 2010 results are provided for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2009.

7/15/2010

Lakefront Utility Services Inc.

Electric and Lighting

ESTIMATED BENEFIT EXPENSE (CICA 3461)

Final

	Calendar Year 2009	Projected Calendar Year 2010
Discount Rate - January 1	6.00%	5.00%
Discount Rate - December 31	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*
A. Determination of Benefit Expense		
Current Service Cost	6,010	6,311
Interest on Benefits	15,068	14,327
Expected Interest on Assets	-	-
Transitional Obligation/(Asset)	-	-
Actuarial (Gain)/Loss	-	-
Benefit Expense	21,078	20,637
B. Reconciliation of Prepaid Benefit Asset (Liability)		
Accrued Benefit Obligation (ABO) as at December 31	288,149	292,936
Assets as at December 31	-	-
Unfunded ABO	(288,149)	(292,936)
Unrecognized Loss/(Gain)	23,994	23,994
Unrecognized Transitional Obligation	-	-
Prepaid Benefit Asset (Liability)	(264,156)	(268,943)
Prepaid Benefit/(Liability) as at January 1	(257,375)	(264,156)
Benefit Income/(Expense)	(21,078)	(20,637)
Contributions/Benefit Payments by the Employer	14,297	15,850
Prepaid Benefit Asset (Liability)	(264,156)	(268,943)

* Based on estimated employer benefit payments for those expected to be eligible for benefits.

Projected calendar year 2010 results are provided for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2009.

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7/15/2010

Lakefront Utility Services Inc.

Electric and Lighting

ESTIMATED BENEFIT EXPENSE (CICA 3461)

Final

	Calendar Year 2009	Projected Calendar Year 2010
Discount Rate - January 1	6.00%	5.00%
Discount Rate - December 31	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*

C. Calculation of Component Items

Calculation of the Service Cost		
- Current service cost	6,010	6,311
Interest on Benefits		
- ABO at January 1	252,271	288,149
- Current service cost	6,010	6,311
- Benefit payments	(7,149)	(7,925)
- Accrued benefits	251,133	286,535
- Interest	15,068	14,327
Expected Interest on Assets		
- Assets at January 1	-	-
- Funding	7,149	7,925
- Benefit payments	(7,149)	(7,925)
- Expected assets	-	-
- Interest	-	-
Expected ABO as at December 31		
- ABO at January 1	252,271	288,149
- Current service cost	6,010	6,311
- Interest on benefits	15,068	14,327
- Benefit payments	(14,297)	(15,850)
- Expected ABO at December 31	259,052	292,936
Expected Assets as at December 31		
- Assets at January 1	-	-
- Funding	14,297	15,850
- Interest on assets	-	-
- Benefit payments	(14,297)	(15,850)
- Expected Assets at December 31	-	-

Projected calendar year 2010 results are provided for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2009.

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7/15/2010

Lakefront Utility Services Inc.

Electric and Lighting

ESTIMATED BENEFIT EXPENSE (CICA 3461)

Final

	Calendar Year 2009	Projected Calendar Year 2010
Discount Rate - January 1	6.00%	5.00%
Discount Rate - December 31	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*

D. Actuarial (Gain)/Loss

(Gain)/Loss on ABO as at January 1		
- Prepaid Liability as at January 1	257,375	264,156
- Unrecognized Actuarial (Gain)/Loss	-	23,994
- Expected ABO	257,375	288,149
- Actual ABO	252,271	288,149
- (Gain)/Loss on ABO	(5,104)	-
(Gain)/Loss on assets as at January 1		
- Expected assets	-	-
- Actual assets	-	-
- (Gain)/Loss on assets	-	-
Total (Gain)/Loss as at January 1	(5,104)	23,994
10% of ABO as at January 1	25,227	28,815
Total (Gain)/Loss to be amortized	-	-
Expected average remaining service life (years)	6	5
Minimum Amortization for current year	-	-

(Gain)/Loss on ABO at December 31 due to change in discount rate assumption	
- Expected ABO - December 31	259,052
- Actual ABO - December 31	288,149
- (Gain)/Loss on ABO at December 31	29,098
Unamortized (Gain)/Loss	23,994

Projected calendar year 2010 results are provided for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2009.

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7/15/2010

Lakefront Utility Services Inc.

Water

ESTIMATED BENEFIT EXPENSE (CICA 3461)

Final

	Calendar Year 2009	Projected Calendar Year 2010
Discount Rate - January 1	6.00%	5.00%
Discount Rate - December 31	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*
A. Determination of Benefit Expense		
Current Service Cost	8,060	8,463
Interest on Benefits	15,410	15,094
Expected Interest on Assets	-	-
Transitional Obligation/(Asset)	-	-
Actuarial (Gain)/Loss	(85)	-
Benefit Expense	23,385	23,556
B. Reconciliation of Prepaid Benefit Asset (Liability)		
Accrued Benefit Obligation (ABO) as at December 31	297,747	312,627
Assets as at December 31	-	-
Unfunded ABO	(297,747)	(312,627)
Unrecognized Loss/(Gain)	4,162	4,162
Unrecognized Transitional Obligation	-	-
Prepaid Benefit Asset (Liability)	(293,584)	(308,465)
Prepaid Benefit/(Liability) as at January 1	(279,000)	(293,584)
Benefit Income/(Expense)	(23,385)	(23,556)
Contributions/Benefit Payments by the Employer	8,800	8,676
Prepaid Benefit Asset (Liability)	(293,584)	(308,465)

* Based on estimated employer benefit payments for those expected to be eligible for benefits.

Projected calendar year 2010 results are provided for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2009.

7/15/2010

Lakefront Utility Services Inc.

Water

ESTIMATED BENEFIT EXPENSE (CICA 3461)

Final

	Calendar Year 2009	Projected Calendar Year 2010
Discount Rate - January 1	6.00%	5.00%
Discount Rate - December 31	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*

C. Calculation of Component Items

Calculation of the Service Cost		
- Current service cost	8,060	8,463
Interest on Benefits		
- ABO at January 1	253,172	297,747
- Current service cost	8,060	8,463
- Benefit payments	(4,400)	(4,338)
- Accrued benefits	256,832	301,872
- Interest	15,410	15,094
Expected Interest on Assets		
- Assets at January 1	-	-
- Funding	4,400	4,338
- Benefit payments	(4,400)	(4,338)
- Expected assets	-	-
- Interest	-	-
Expected ABO as at December 31		
- ABO at January 1	253,172	297,747
- Current service cost	8,060	8,463
- Interest on benefits	15,410	15,094
- Benefit payments	(8,800)	(8,676)
- Expected ABO at December 31	267,841	312,627
Expected Assets as at December 31		
- Assets at January 1	-	-
- Funding	8,800	8,676
- Interest on assets	-	-
- Benefit payments	(8,800)	(8,676)
- Expected Assets at December 31	-	-

Projected calendar year 2010 results are provided for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2009.

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7/15/2010

Lakefront Utility Services Inc.

Water

ESTIMATED BENEFIT EXPENSE (CICA 3461)

Final

	Calendar Year 2009	Projected Calendar Year 2010
Discount Rate - January 1	6.00%	5.00%
Discount Rate - December 31	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*

D. Actuarial (Gain)/Loss

(Gain)/Loss on ABO as at January 1		
- Prepaid Liability as at January 1	279,000	293,584
- Unrecognized Actuarial (Gain)/Loss	-	4,162
- Expected ABO	279,000	297,747
- Actual ABO	253,172	297,747
- (Gain)/Loss on ABO	(25,828)	-
(Gain)/Loss on assets as at January 1		
- Expected assets	-	-
- Actual assets	-	-
- (Gain)/Loss on assets	-	-
Total (Gain)/Loss as at January 1	(25,828)	4,162
10% of ABO as at January 1	25,317	29,775
Total (Gain)/Loss to be amortized	(511)	-
Expected average remaining service life (years)	8	5
Minimum Amortization for current year	(85)	-

(Gain)/Loss on ABO at December 31 due to change in discount rate assumption	
- Expected ABO - December 31	267,841
- Actual ABO - December 31	297,747
- (Gain)/Loss on ABO at December 31	29,905
Unamortized (Gain)/Loss	4,162

Projected calendar year 2010 results are provided for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2009.

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12/14/2009

Lakefront Utility Services Inc.

Total

ESTIMATED BENEFIT EXPENSE (CICA 3461)

Draft

	Calendar Year 2009	Projected Calendar Year 2010
Discount Rate - January 1	6.00%	5.00%
Discount Rate - December 31	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*
A. Determination of Benefit Expense		
Current Service Cost	14,070	14,774
Interest on Benefits	30,478	29,420
Expected Interest on Assets	-	-
Transitional Obligation/(Asset)	-	-
Actuarial (Gain)/Loss	(85)	-
Benefit Expense	44,463	44,194
B. Reconciliation of Prepaid Benefit Asset (Liability)		
Accrued Benefit Obligation (ABO) as at December 31	585,896	605,563
Assets as at December 31	-	-
Unfunded ABO	(585,896)	(605,563)
Unrecognized Loss/(Gain)	28,156	28,156
Unrecognized Transitional Obligation	-	-
Prepaid Benefit Asset (Liability)	(557,740)	(577,407)
Prepaid Benefit/(Liability) as at January 1	(536,375)	(557,740)
Benefit Income/(Expense)	(44,463)	(44,194)
Contributions/Benefit Payments by the Employer	23,098	24,526
Prepaid Benefit Asset (Liability)	(557,740)	(577,407)

* Based on estimated employer benefit payments for those expected to be eligible for benefits.

Electric 264156 268943
Water 293584 308465
557740 577,408

Projected calendar year 2010 results are provided for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2009.

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12/14/2009

Lakefront Utility Services Inc.

Electric and Lighting

ESTIMATED BENEFIT EXPENSE (CICA 3461)

Draft

	Calendar Year 2009	Projected Calendar Year 2010
Discount Rate - January 1	6.00%	5.00%
Discount Rate - December 31	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*
A. Determination of Benefit Expense		
Current Service Cost	6,010	6,311
Interest on Benefits	15,068	14,327
Expected Interest on Assets	-	-
Transitional Obligation/(Asset)	-	-
Actuarial (Gain)/Loss	-	-
Benefit Expense	21,078	20,637
B. Reconciliation of Prepaid Benefit Asset (Liability)		
Accrued Benefit Obligation (ABO) as at December 31	288,149	292,936
Assets as at December 31	-	-
Unfunded ABO	(288,149)	(292,936)
Unrecognized Loss/(Gain)	23,994	23,994
Unrecognized Transitional Obligation	-	-
Prepaid Benefit Asset (Liability)	(264,156)	(268,943)
Prepaid Benefit/(Liability) as at January 1	(257,375)	(264,156)
Benefit Income/(Expense)	(21,078)	(20,637)
Contributions/Benefit Payments by the Employer	14,297	15,850
Prepaid Benefit Asset (Liability)	(264,156)	(268,943)

* Based on estimated employer benefit payments for those expected to be eligible for benefits.

Projected calendar year 2010 results are provided for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2009.

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12/14/2009

Lakefront Utility Services Inc.

Water

ESTIMATED BENEFIT EXPENSE (CICA 3461)

Draft

	Calendar Year 2009	Projected Calendar Year 2010
Discount Rate - January 1	6.00%	5.00%
Discount Rate - December 31	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*

A. Determination of Benefit Expense

Current Service Cost	8,060	8,463
Interest on Benefits	15,410	15,094
Expected Interest on Assets	-	-
Transitional Obligation/(Asset)	-	-
Actuarial (Gain)/Loss	(85)	-
Benefit Expense	23,385	23,556

B. Reconciliation of Prepaid Benefit Asset (Liability)

Accrued Benefit Obligation (ABO) as at December 31	297,747	312,627
Assets as at December 31	-	-
Unfunded ABO	(297,747)	(312,627)
Unrecognized Loss/(Gain)	4,162	4,162
Unrecognized Transitional Obligation	-	-
Prepaid Benefit Asset (Liability)	(293,584)	(308,465)
Prepaid Benefit/(Liability) as at January 1	(279,000)	(293,584)
Benefit Income/(Expense)	(23,385)	(23,556)
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Prepaid Benefit Asset (Liability)	(293,584)	(308,465)

* Based on estimated employer benefit payments for those expected to be eligible for benefits.

Projected calendar year 2010 results are provided for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2009.

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7/15/2010

Lakefront Utility Services Inc.

Total

ESTIMATED BENEFIT EXPENSE (CICA 3461)

Final

	Calendar Year 2009	Projected Calendar Year 2010
Discount Rate - January 1	6.00%	5.00%
Discount Rate - December 31	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*
A. Determination of Benefit Expense		
Current Service Cost	14,070	14,774
Interest on Benefits	30,478	29,420
Expected Interest on Assets	-	-
Transitional Obligation/(Asset)	-	-
Actuarial (Gain)/Loss	(85)	-
Benefit Expense	44,463	44,194
B. Reconciliation of Prepaid Benefit Asset (Liability)		
Accrued Benefit Obligation (ABO) as at December 31	585,896	605,563
Assets as at December 31	-	-
Unfunded ABO	(585,896)	(605,563)
Unrecognized Loss/(Gain)	28,156	28,156
Unrecognized Transitional Obligation	-	-
Prepaid Benefit Asset (Liability)	(557,740)	(577,407)
Prepaid Benefit/(Liability) as at January 1	(536,375)	(557,740)
Benefit Income/(Expense)	(44,463)	(44,194)
Contributions/Benefit Payments by the Employer	23,098	24,526
Prepaid Benefit Asset (Liability)	(557,740)	(577,407)

* Based on estimated employer benefit payments for those expected to be eligible for benefits.

Projected calendar year 2010 results are provided for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2009.

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OVERVIEW

The purpose of this evidence is to summarize the method and cost of financing capital requirements for the 2012 Test year.

Lakefront Utilities Inc. was incorporated April 12, 2000 in accordance with the requirements of the *Electricity Act, 1998,* S.O. 1998, c. 15, Schedule A. LUI is a subsidiary of the Town of Cobourg Holdings Inc.

Capital Structure:

LUI has a current deemed capital structure of 60.0% debt 40.0% equity.

LUI has prepared this rate application with a deemed capital structure of 56% Long Term Debt, 4% Short Term Debt, and 40% Equity to comply with the Report of the Board on the Cost of Capital for Ontario Regulated Utilities, March 3, 2011.

Table 5-1 details LUI's proposed deemed capital structure for 2012 in the Board's Appendix 2-N format, as well as the 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, and 2011 Bridge Year.

Table 5-2 details the 2008 Board Approved capital structure, and the actual results for the fiscal years 2008-2011, as well as proposed results for 2011-2012.

TABLE 5 – 1 CAPITAL STRUCTURE

TABLE 5-1

Deemed Capital Structure for 2008

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	6,798,651	49.30%	6.10%	414,718
Unfunded Short Term Debt	551,615	4.00%	4.47%	24,657
Total Debt	7,350,266	53.30%		439,375
Common Share Equity	6,440,101	46.70%	8.57%	551,917
Total equity	6,440,101	46.70%		551,917
Total Rate Base	13,790,367	100.00%	7.19%	991,292

Deemed Capital Structure for 2009

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	7,389,581	52.70%	6.10%	450,764
Unfunded Short Term Debt	560,879	4.00%	1.33%	7,460
Total Debt	7,950,460	56.70%		458,224
Common Share Equity	6,071,515	43.30%	8.57%	520,329
Total equity	6,071,515	43.30%		520,329
Total Rate Base	14,021,975	100.00%	6.98%	978,553

Deemed Capital Structure for 2010

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	8,017,136	56.00%	6.10%	489,045
Unfunded Short Term Debt	572,653	4.00%	2.07%	11,854
Total Debt	8,589,789	60.00%		500,899
Common Share Equity	5,726,526	40.00%	9.85%	564,063
Total equity	5,726,526	40.00%		564,063
Total Rate Base	14,316,315	100.00%	7.44%	1,064,962

Deemed Capital Structure for 2011

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	8,807,776	56.00%	5.75%	506,144
Unfunded Short Term Debt	629,127	4.00%	2.46%	15,477
Total Debt	9,436,903	60.00%		521,621
Common Share Equity	6,291,269	40.00%	9.58%	602,704
Total equity	6,291,269	40.00%		602,704
Total Rate Base	15,728,172	100.00%	7.15%	1,124,324

Deemed Capital Structure for 2012

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	9,814,514	56.00%	4.83%	474,102
Unfunded Short Term Debt	701,037	4.00%	2.46%	17,246
Total Debt	10,515,551	60.00%		491,348
Common Share Equity	7,010,367	40.00%	9.58%	671,593
Total equity	7,010,367	40.00%		671,593
Total Rate Base	17,525,919	100.00%	6.64%	1,162,941

COST OF CAPITAL

Return on Equity

LUI is requesting a return on equity ("ROE") for the 2012 Test year of 9.58% in accordance with the Cost of Capital Parameter Updates for 2011 Cost of Service Applications issued by the OEB on March 3, 2011. LUI understands that the OEB will be finalizing the ROE for 2012 rates based on January 2012 market interest rate information. LUI's use of an ROE of 9.58% is without prejudice to any revised ROE that may be adopted by the OEB in early 2012.

Cost of Debt

Long Term Debt

LUI is requesting a weighted average return on long term debt for the 2012 Test Year of 4.83%. LUI currently holds a long term note payable to its Shareholder, Town of Cobourg (affiliated debt) at a return of 7.25%, and an expected 2011 rate of 4.24% on its $3,800,000 loan with Infrastructure Ontario, and the 2011 expected rate of 4.24% on the new debt with TD Canada Trust. See Table 5-2. The new debt with TD Canada Trust is required in order to finance the capital projects as well as expand SCADA and the OWC. See Exhibit 2 for details on the substation capital project. This debt is with a commercial institution, and not any affiliated parties.

LUI submits the fixed interest rate on the promissory note to the Town was established at the time of incorporation when the deemed debt rate was 7.25%. The fixed rate 7.25% was agreed upon (using the OEB guideline) in order to provide both LUI and the Town of Cobourg with a predetermined rate of interest. A copy of the Promissory note with the Town of Cobourg is shown in Appendix A to this Exhibit. LUI is **not** requesting a change in the long term deemed rate of 5.32%, as provided by the Ontario Energy Board and would like to have this fact noted in this rate application.

Short Term Debt

LUI is requesting a return on Short Term Debt for the 2012 Test year of 2.46% in accordance with the Cost of Capital Parameter Updates for 2011 Cost of Service Applications issued by the OEB on March 3, 2011. LUI understands that the OEB will be finalizing the return on short term debt for 2012 rates based on January 2012 market interest rate information. LUI's use of a Return on Short Term Debt of 2.46% is without prejudice to any revised ROE that may be adopted by the OEB in early 2012.

TABLE 5-2 COST OF LONG-TERM DEBT

TABLE 5-2

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
Promissory Note	Town of Cobourg	Y	October 1, 2001	7,000,000	Unspecified	6.10%	2008	427,000
Promissory Note	Town of Cobourg	Y	October 1, 2001	7,000,000	Unspecified	6.10%	2009	427,000
Loan Payable	Infrastructure Ontario	N	December 1, 2009	1,653,000	Unspecified	6.10%	2009	100,833
Promissory Note	Town of Cobourg	Y	October 1, 2001	7,000,000	Unspecified	6.10%	2010	427,000
Loan Payable	Infrastructure Ontario	N	October 1, 2010	3,547,658		6.10%	2010	216,407
Promissory Note	Town of Cobourg	Y	October 1, 2001	7,000,000	Unspecified	6.10%	2011	427,000
Loan Payable	Infrastructure Ontario	N	November 1, 2011	3,800,000		5.32%	2011	202,160
Loan Payable	TD CT	N	November 1, 2011	2,000,000		5.32%	2011	106,400
Promissory Note	Town of Cobourg	Y	October 1, 2001	7,000,000	Unspecified	5.32%	2012	372,400
Loan Payable	TD CT	N	November 1, 2011	2,000,000		4.24%	2012	84,800
Loan Payable	Infrastructure Ontario	N	November 1, 2011	3,800,000		4.24%	2012	161,120
								0
								0
								0
								0
								0
								0
								0
								0
								0
								0

2008 Total Long Term Debt	7,000,000	Total Interest Cost for 2008	427,000
		Weighted Debt Cost Rate for 2008	6.10%
2009 Total Long Term Debt	8,653,000	Total Interest Cost for 2009	527,833
		Weighted Debt Cost Rate for 2009	6.10%
2010 Total Long Term Debt	10,547,658	Total Interest Cost for 2010	643,407
		Weighted Debt Cost Rate for 2010	6.10%
2011 Total Long Term Debt	12,800,000	Total Interest Cost for 2011	735,560
		Weighted Debt Cost Rate for 2011	5.75%
2012 Total Long Term Debt	12,800,000	Total Interest Cost for 2012	618,320
		Weighted Debt Cost Rate for 2012	4.83%

APPENDIX A – PROMISSORY NOTE

COPY

RECEIPT

TO: LAKEFRONT UTILITIES INC. (the "Corporation")

RE: Promissory Note for $7,000,000 (the "New Note") dated September 12th, 2006 and effective May 1, 2000 issued by the Corporation to the Corporation of the Town of Cobourg (the "Town"), pursuant to the Town's By-Law No. 31-00, as amended, and issued in replacement of a previously issued promissory note in the amount of $4,000,000 dated May 1, 2000;

The Town hereby acknowledges receipt from the Corporation of the New Note.

DATED the 20th day of Nov. , 2006.

THE CORPORATION OF THE
TOWN OF COBOURG

by Peter Delanty
Peter Delanty
Mayor

by
Richard Stinson
Municipal Clerk

COPY

PROMISSORY NOTE

Effective: May 1, 2000 Principal Sum: $7,000,000.00

FOR VALUE RECEIVED, Lakefront Utilities Inc. (the "Borrower") promises to pay on demand to or to the order of The Corporation of the Town of Cobourg (the "Lender") its successors and assigns the principal sum of SEVEN MILLION DOLLARS ($7,000,000) in lawful money of Canada at the Lender's office at 207 Division Street, P.O. Box 577, Cobourg, Ontario K9A 4L3, or at such other place as the Lender may designate by notice in writing to the Borrower and to pay interest on the said principal sum from the date hereof at the below indicated rate in like money at the same place, calculated and payable monthly on the last day of each calendar month commencing with the month of May, 2000 and continuing until the said principal sum and all interest thereon is fully paid and satisfied; and, should the Borrower at any time make default in the payment of any principal or interest, to pay interest on the amount in default at the same rate in like money at the same place and monthly on the same date both before and after default as well as before and after judgment until payment in full.

INTEREST RATE: 7.25% per annum, being the debt cost rate per annum established by the Ontario Energy Board as applicable to the Borrower as set out in Chapter 3 of the Ontario Energy Board's electricity Distribution Rate Handbook (the "PBR Handbook") issued March 9, 2000.

The Borrower hereby waives presentment, notice of dishonour, protest and notice of protest.

DATED at Cobourg, Ontario, the 12th day of September, 2006 effective the 1st day of May, 2000.

LAKEFRONT UTILITIES INC.

per: _____
President

per: _____
Treasurer

1

AGREEMENT

RE: **Values of the WiresCo Assets and the Promissory Note issued to The Corporation of the Town of Cobourg (the "Town") pursuant to the Town's Amended By-Law No. 31-00 dated November 7, 2000 (the "Transfer By-Law").**

RECITALS:

1. Pursuant to resolutions of the directors of Lakefront Utilities Inc. ("WiresCo") dated May 1, 2000 (the "Resolutions"), the directors approved and authorized, as at May 1, 2000, the issuance of 9,999,999 Common shares for a consideration of $8,380,000 and a promissory note in the principal amount of $4,000,000 (the "$4,000,000 Note") in payment of the consideration for the WiresCo Assets (defined in the Resolutions as the "Cobourg Assets") (the "WiresCo Assets") transferred and assigned by the Town to WiresCo pursuant to the Transfer By-Law;

2. Pursuant to the pre-incorporation agreement (the "Agreement") dated as at May 1, 2000 between the Town and The Corporation of the Village of Colborne, as amended, and pursuant to the Transfer By-Law, the purchase price for the WiresCo Assets is the fair market value of the WiresCo Assets on May 1, 2000 (the "Effective Date") and such fair market value is deemed to be the net book value of the WiresCo Assets on the Effective Date subject to adjustment as a result of any audit or valuation conducted after the Effective Date pursuant to the Agreement;

3. AND WHEREAS since the execution of the Resolutions the parties have determined that the aggregate consideration for the WiresCo Assets should have been $15,380,000 as reflected in the audited financial statements for the period ended April 30, 2000 of the Cobourg Public Utilities Commission and, further, that the amount of the promissory note issued in partial payment of the consideration for the WiresCo Assets should have been issued in the principal amount of $7,000,000;

NOW THEREFORE, pursuant to the Transfer By-Law and the Agreement, the Town and HoldCo and the President of HoldCo agree:

1. The consideration to be paid for the WiresCo Assets on the Effective Date is $15,380,000.

2. A promissory note in the amount of $7,000,000 (the "New Note") shall be issued, effective as of the Effective Date, by WiresCo to the Town in partial payment of the consideration for the WiresCo Assets, being the balance remaining after the assumption by the Corporation of the WiresCo Liabilities (as defined in the Transfer By-Law) and the issuance to the Town of 9,999,999 Common shares of the Corporation for the consideration of $8,380,000.

4. The delivery to WiresCo of a copy of this Agreement shall be full and sufficient authority and instructions for WiresCo to issue and deliver to the Town the New Note, subject to the return to WiresCo, for cancellation, of the $4,000,000 Note.

DATED as of the 30th day of NOV. , 2006.

THE CORPORATION OF THE
TOWN OF COBOURG

by _____
MAYOR PETER DELANTY

by _____
MUNICIPAL CLERK
RICHARD STIMESON

TOWN OF COBOURG HOLDINGS
INC.

per: _____
Director JOAN E. CHALKVICH

per: _____
Director ADRIAN LAWTHORNE

President of Town of Cobourg
Holdings Inc.
BRUCE R. CRAIG

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REVENUE DEFICIENCY

OVERVIEW

LUI has provided detailed calculations supporting its 2012 Revenue Deficiency. LUI has used MIFRS (Modified International Financial Reporting Standards) in order to calculate the 2012 Revenue Deficiency for 2012. LUI's Revenue Deficiency when grossed up for PILS is $ 743,941 . This is calculated as the difference between the 2012 Test Year Revenue Requirement of $ 4,752,741 and the Forecast 2012 Test Year Revenues Requirement at LUI's 2011 approved distribution rates of $ **4,008,801** . Table 6-0 below provides the revenue deficiency calculations for the 2012 Test Year at Existing 2011 OEB approved rates and the 2012 Test Year Revenue Requirement.

REVENUE REQUIREMENT

LUI'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

LUI'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 Calculation of Revenue Deficiency

Lakefront Utilities Inc.
Revenue Deficiency Determination

Description	2011 Bridge	2012 Test Existing Rates	2012 Test - Required Revenue
Revenue			
Revenue Deficiency			**743,940.79**
Distribution Revenue	4,019,092	4,008,801	4,008,801
Other Operating Revenue (Net)	298,240	378,462	378,462
Total Revenue	**4,317,332**	**4,387,263**	**5,131,204**
Costs and Expenses			
Administrative & General, Billing & Collecting	1,563,298	1,796,132	1,796,132
Operation & Maintenance	885,828	1,271,182	1,271,182
Depreciation & Amortization	1,124,562	816,209	816,209
Property Taxes	48,099	49,542	49,542
Capital Taxes	0	0	0
Deemed Interest	521,621	491,348	491,348
Total Costs and Expenses	**4,143,408**	**4,424,412**	**4,424,412**
Less OCT Included Above	0	0	0
Total Costs and Expenses Net of OCT	**4,143,408**	**4,424,412**	**4,424,412**
Utility Income Before Income Taxes	**173,924**	**(37,150)**	**706,791**
Income Taxes:			
Corporate Income Taxes	32,287	(80,113)	35,198
Total Income Taxes	**32,287**	**(80,113)**	**35,198**
Utility Net Income	**141,637**	**42,963**	**671,593**
Capital Tax Expense Calculation:			
Total Rate Base	15,728,172	17,525,919	17,525,919
Exemption	15,000,000	15,000,000	15,000,000
Deemed Taxable Capital	**728,172**	**2,525,919**	**2,525,919**
Ontario Capital Tax	0	0	0
Income Tax Expense Calculation:			
Accounting Income	173,924	(37,150)	706,791
Tax Adjustments to Accounting Income	(59,632)	(479,707)	(479,707)
Taxable Income	**114,292**	**(516,857)**	**227,084**
Income Tax Expense	32,287	(80,113)	35,198
Tax Rate Refecting Tax Credits	28.25%	15.50%	15.50%
Actual Return on Rate Base:			
Rate Base	15,728,172	17,525,919	17,525,919
Interest Expense	521,621	491,348	491,348
Net Income	141,637	42,963	671,593
Total Actual Return on Rate Base	**663,257**	**534,311**	**1,162,941**
Actual Return on Rate Base	4.22%	3.05%	6.64%
Required Return on Rate Base:			
Rate Base	15,728,172	17,525,919	17,525,919
Return Rates:			
Return on Debt (Weighted)	5.53%	4.67%	4.67%
Return on Equity	9.58%	9.85%	9.85%
Deemed Interest Expense	521,621	491,348	491,348
Return On Equity	602,704	671,593	671,593
Total Return	**1,124,324**	**1,162,941**	**1,162,941**
Expected Return on Rate Base	7.15%	6.64%	6.64%
Revenue Deficiency After Tax	**461,067**	**628,630**	**(0)**
Revenue Deficiency Before Tax	**642,602**	**743,941**	**(0)**

COST DRIVERS ON REVENUE DEFICIENCY

LUI notes there are several factors that contribute to the gross revenue deficiency of $ 743,941 for the 2012 Test Year. The following discussion highlights some significant items that contribute to this deficiency.

The revenue deficiency is primarily the result of increasing OM&A expenses (as previously mentioned in the Cost Driver Table 4.14 in Exhibit 4). The cost drivers with the most significant impacts are Third Party Services, Non-Union Wage Adjustments, Meter Maintenance, Consulting Regulatory Fees, Capital Maintenance, Collections, and Software Maintenance. A brief synopsis of the effect these cost drivers have on LUI's OM&A is shown below.

Increases in OM&A expenses are primarily due to:

- ✓ Increases in direct and indirect labour costs
  - o Economic wage increases have increased salaries and wages paid each year. Effective Feb 1st of each year, economic increases negotiated through collective agreements were 3% for four years effective 2010 to 2013 respectively.
  - o LUI is requiring the hiring of new staff of 5.75 Full Time Equivalent positions between 2008 and 2012. Of these positions, there will be a net addition of 3.25 unionized staff, 1.75 Non-unionized staff, and 0.75 Management staff (non-union). LUI requires this new complement of staff to properly recover from attrition of its workforce, and also to efficiently execute industry initiatives. A detailed discussion can be found in Exhibit 4 following Table 4.36 "2008-2012 Employee Complement Compensation".
  - o Cost associated with hiring third party services to complete activities including audit, legal, maintenance services, collection services, and disposal services. The hiring of third party services is cost effective as these services

are not required on a full time basis, and expenses can be removed from daily operating costs.

- ✓ Inflation has increased from 2.4% in 2008 to 3% in 2011 Bridge and 2012 Test Year. All utilities will be confronted with increased operational costs due to the rising inflation costs to services.
- ✓ Increases have occurred due to planned maintenance programs for proactive measures against the aging of LUI's capital infrastructure as well as initiatives undertaken as an industry i.e. Smart Meter, Conservation Demand Management, IFRS Compliance and Asset Management Plan etc.
- ✓ Maintenance programs are not only used as a method of preserving useful life of equipment and buildings, but it is required to continue operations and promote a safe environment. Assets must be kept within safety code, and in working order to operate daily and this is proving to be an increasing expense yearly.
- ✓ Increasing Regulatory Expenses
  - o LUI's regulatory expenses have been steadily increasing year to year (discussed in Exhibit 4) and it further expects to incur approximately $103,000 in additional expenses due to the 2012 rate application.
- ✓ Increasing Collection Expenses
  - o Collections accounts have been an increasing driver due to the economic environment and recession in 2008. A large increase is seen as customer late payments become more frequent and there is decreased job security. LUI's service area has experienced a shift in employment as a result of economic downfalls.
- ✓ Increasing Software Maintenance Expenses
  - o Software has traditionally been a cost driver that exceeds the inflation rate as technology rapidly adapts to be more user friendly and service the industry in the best method possible. LUI expects this cost to continue increasing as the electricity industry works through Smart Metering technology and must maintain adequate and appropriate Service Level

Agreements. To adapt with the new technologies, other software will require updates for compatibility purposes.

Additions to capital assets in all years exceeded depreciation levels resulting in an increased rate base on which the rate of return is calculated. In particular, in 2011, LUI initiated the construction of an expansion to the OWC in 2011/2012. As mentioned in Exhibit 2 LUI requires additional office space due to its increased initiatives and operations.

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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 first set of Cost Allocation Information Filing Guidelines for Electricity Distributors, the Cost Allocation Model and User Instructions for the Model. Subsequently on July 8, 2011, the Board issued a new Cost Allocation Model (the "Model"), as well as new Instructions and Filing Guidelines. LUI prepared and filed a cost allocation information filing consistent with LUI's understanding of the new (updated July 8, 2011) Directions, the Guidelines, the Model and the Instructions. For the purposes of this application, LUI has used the Board-approved Cost Allocation model and methodology and has updated the cost allocation study previously filed to reflect 2012 test year costs, customer numbers and demand values. The 2012 demand values are based on the weather normalized load forecast used to design rates.

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.

LUI has used the Board-approved Cost Allocation model and methodology and updated the values from the Hydro One Run 2 load forecast using 2012 weather normalized forecasted data information.

Summary of the 2012 Updated Results and Proposed Changes

The data used in the updated Cost Allocation Model is consistent with LUI's cost data that supports its proposed 2012 revenue requirement outlined in this application. Consistent with

the Guidelines, LUI's assets were broken out into primary and secondary distribution functions. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to LUI, its engineering records, and its customer and financial information systems. An Excel version of the updated cost allocation study has been included in the electronic filing with the Board.

Capital contributions, depreciation and accumulated depreciation by USoA are consistent with the information provided in the 2012 continuity statement shown in Exhibit 2. The rate class customer data used in the updated cost allocation study is consisted with the 2012 customer forecast in Exhibit 3. The load profile 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 following Table 7-0 outlines the scaling factors used by rates class.

As noted above, the results of a cost allocation study are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

The following Table 7-0 outlines the scaling factors used by rate class.

Table 7-0 – Scaling Factors by Rate Class

RATE CLASS	2008 Approved Cost Allocation Model (kWh)	2012 Cost Allocation Model (kWh)	Scaling Factor
Residential	69,840,545.00	73,125,152.06	101.2%
GS <50	34,387,927.00	35,160,634.14	105.1%
GS> 50-2999	117,177,139.00	120,608,901.96	96.0%
GS > 3000-4999	55,377,072.00	19,295,355.53	31.2%
Street Light	1,894,110.00	1,215,575.49	60.7%
Sentinel	39,498.00	78,431.48	144.7%
Unmetered Scattered Load	492,298.00	716,623.00	152.3%
	279,208,589.00	**250,200,673.65**	**89.6%**

The allocated cost by rate class for the 2008 Cost of Service filing and the 2012 updated study are provided in the following Table 7-1. The results shown under 2008 (Costs Allocated from Previous Study) column have been revised to exclude the "costs" and "revenues" of the transformation allowance as outlined in the June 28, 2011 filing requirements.

Table 7-1 – Allocated Costs

Classes	Costs Allocated from Previous Study (2008)	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 1,574,342	40.80%	$ 2,838,659	55.32%
GS < 50 kW	$ 474,450	12.29%	$ 723,733	14.10%
GS 50 - 2999 KW	$ 791,120	20.50%	$ 1,122,655	21.88%
GS 3000 - 4999	$ 493,008	12.78%	$ 136,235	2.66%
Street Lighting	$ 482,541	12.50%	$ 250,482	4.88%
Sentinel Lighting	$ 9,841	0.25%	$ 6,222	0.12%
Unmetered Scattered Load (USL)	$ 33,811	0.88%	$ 53,217	1.04%
Total	$ 3,859,113	100.00%	$ 5,131,204	100.00%

Proposed Adjustment to Cost Allocation

In the Report of the Board, dated March 31, 2011, in the Cost Allocation proceeding EB-2010-0219, the Board revised what it considered to be appropriate ranges of revenue to cost ratios

which are summarized in the last column of Table 7-2 below. Table 7-2 also provides LUI's proposed 2012 revenue to cost ratios. The proposed revenue to cost ratios reflects adjustments to revenue to address cross subsidization.

Table 7-2 - LUI's Revised Revenue to Cost Ratios

Class	Previously Approved Ratios Most Recent Year: 2011	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	97.64%	88.55	97.64	85 - 115
GS < 50 kW	107.43%	102.60	107.43	80 - 120
GS 50 - 2999 KW	154.43%	133.53	112.18	80 - 120
GS 3000 - 4999	20.05%	41.49	50.50	80 - 120
Street Lighting	70.00%	108.32	80.00	70 - 120
Sentinel Lighting	70.06%	113.32	90.00	80 - 120
Unmetered Scattered Load (USL)	99.95%	76.95	90.00	80 - 120

LUI is proposing in this application to realign 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. For 2012, the realignment will move the GS> 3000-4999 class from 20.05 in 2011 (41.49% status quo) up to 50.50%, which is closer to the minimum range, and will continue to move over the Cost of Service Rate Years; GS> 50-2999 will move down to 112.18% in to the Board Approved range; Streetlights will continue to close the gap from 70% in 2011 to 80%; and Sentinel Lighting will move to 90% from 70.06% in 2011, to assist with rate mitigation, just outside of the minimum range to 100% within the Board Approved range. LUI is proposing no change to the Residential class nor the GS>50-2999. All customer classes, with the exception of GS> 3000-4999 class, will be within the Board Approved Revenue to Cost Ratio Ranges with this Application. Given the extent of the shortfall outside of the required range for GS> 3000-4999 class, LUI is proposing to bring this class into the required range of 80% by the year 2016 with an incremental increase of 7.5% per year over 4 years.

The following Table 7-3 provides a forecast of the Proposed Revenues to Cost Ratios that are expected to be changed/adjusted going forward to the year 2014. The change occurs to the GS>3000-4999 customer class and the offsetting adjustments to deal with this, will be assessed as needed in future years.

Table 7-3 Proposed Revenue to Cost Ratios

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2012	2013	2014	
	%	%	%	%
Residential	97.64			85 - 115
GS < 50 kW	107.43			80 - 120
GS 50 - 2999 KW	112.18			80 - 120
GS 3000 - 4999	50.50	57.50	65.00	80 - 120
Large User, if applicable				85 - 115
Street Lighting	80.00			70 - 120
Sentinel Lighting	90.00			80 - 120
Unmetered Scattered Load (USL)	90.00			80 - 120
Other class, if applicable				
Embedded distributor, if applicant is a host distributor				

The following Table 7-4 provides information on calculated class revenues. The resulting 2012 proposed base revenue will be the amount used in Exhibit 8 to design the proposed distribution rates and charge it this Application.

Table 7-4 Calculated Class Revenues

Classes (same as previous table)	Column 7B Load Forecast (LF) X current approved rates	Column 7C LF X current approved rates X (1 + d)	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 1,938,972	$ 2,298,799	$ 2,556,790	$ 214,877
GS < 50 kW	$ 582,323	$ 690,388	$ 725,309	$ 52,162
GS 50 - 2999 KW	$ 1,198,646	$ 1,421,087	$ 1,181,345	$ 78,040
GS 3000 - 4999	$ 41,451	$ 49,144	$ 61,414	$ 7,384
Street Lighting	$ 210,576	$ 249,654	$ 178,720	$ 21,666
Sentinel Lighting	$ 5,503	$ 6,524	$ 5,072	$ 528
Unmetered Scattered Load (USL)	$ 31,331	$ 37,145	$ 44,091	$ 3,805
Total	$ 4,008,801	$ 4,752,740	$ 4,752,742	$ 378,462

2012 UPDATED COST ALLOCATION STUDY RESULTS

LUI used the Board-approved Cost Allocation Model and followed the instructions and guidelines issued by the Board to enter the 2012 data into this model. LUI has made the changes to the transformer allowance and Low voltage treatments according to the latest filing guidelines issued by the Board for the Cost of Service rate applications.

LUI populated the information on Sheet I3, Trial Balance Data with the 2012 forecasted data based on the 2011 and 2012 average and input the Target Net Income, PILs, Deemed interest on long term debt, specific service charges information and the targeted revenue requirement and rate base.

On Sheet I4, Break-Out of Assets, LUI updated the allocation of the accounts based on 2012 values.

In Sheet I5, Miscellaneous data, LUI updated the deemed equity component of rate base and the monthly service charges.

In Sheet I6, Customer Data, LUI entered all information updated with 2012 forecast data.

LUI updated the meter information on Sheet I7.1 and the meter reading information on I7.2.

On sheet I8, Demand data is based on the output of our load forecast model. The load profile from the 2004 data received from Hydro One, Run 2 and the weather normalized 2011 forecast data was used to calculate the 1 NCP, 4 NCP, 12 NCP, 1 CP, 4 CP and the 12CP demand data. No direct allocations were used.

The revenue to cost ratios for the 2012 updated study is provided in Table 7-5 below;

Table 7-5 – Revenue to Cost Ratios Revenue to Cost Ratios from LUI's Updated 2012 Cost Allocation Model

Rate Base Assets		Total	1 Residential	2 General Service Less Than 50 kW	3 General Service 50 to 2,999 kW	5 General Service 3,000 to 4,999 kW	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$4,008,802	$1,938,972	$582,323	$1,198,646	$41,451	$210,576	$5,503	$31,331
mi	Miscellaneous Revenue (mi)	$378,462	$214,877	$52,162	$78,040	$7,384	$21,666	$528	$3,805
	Miscellaneous Revenue Input equals Output								
	Total Revenue at Existing Rates	$4,387,264	$2,153,848	$634,485	$1,276,686	$48,836	$232,241	$6,031	$35,136
	Factor required to recover deficiency (1 + D)	1.1856							
	Distribution Revenue at Status Quo Rates	$4,752,741	$2,298,799	$690,388	$1,421,087	$49,144	$249,654	$6,525	$37,146
	Miscellaneous Revenue (mi)	$378,462	$214,877	$52,162	$78,040	$7,384	$21,666	$528	$3,805
	Total Revenue at Status Quo Rates	$5,131,204	$2,513,676	$742,550	$1,499,127	$56,528	$271,319	$7,053	$40,950
	Expenses								
di	Distribution Costs (di)	$1,045,524	$508,927	$131,568	$282,539	$38,435	$78,719	$1,769	$3,566
cu	Customer Related Costs (cu)	$725,956	$499,175	$135,303	$65,418	$1,473	$141	$340	$24,106
ad	General and Administration (ad)	$1,345,376	$761,819	$200,894	$269,027	$31,125	$60,885	$1,610	$20,016
dep	Depreciation and Amortization (dep)	$816,209	$448,451	$104,619	$192,282	$24,183	$43,516	$983	$2,175
INPUT	PILs (INPUT)	$35,198	$18,222	$4,446	$9,206	$1,205	$1,975	$45	$99
INT	Interest	$491,348	$254,375	$62,067	$128,518	$16,822	$27,567	$624	$1,376
	Total Expenses	$4,459,610	$2,490,970	$638,897	$946,991	$113,242	$212,803	$5,370	$51,337
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$671,593	$347,690	$84,835	$175,664	$22,992	$37,679	$853	$1,880
	Revenue Requirement (includes NI)	$5,131,204	$2,838,659	$723,733	$1,122,655	$136,235	$250,482	$6,222	$53,217
	Revenue Requirement Input equals Output								
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$22,665,380	$11,706,492	$3,005,932	$5,811,691	$713,881	$1,330,154	$30,015	$67,214
gp	General Plant - Gross	$1,937,453	$1,017,987	$252,708	$484,334	$59,552	$114,586	$2,590	$5,696
accum dep	Accumulated Depreciation	($8,695,275)	($4,341,135)	($1,170,404)	($2,356,925)	($295,833)	($494,162)	($11,125)	($25,692)
co	Capital Contribution	($2,307,659)	($1,332,327)	($364,852)	($397,224)	($16,636)	($183,536)	($4,125)	($8,958)
	Total Net Plant	$13,599,899	$7,051,017	$1,723,384	$3,541,877	$460,964	$767,042	$17,355	$38,259
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$23,056,611	$6,738,664	$3,240,139	$11,114,409	$1,778,115	$112,018	$7,228	$66,039
	OM&A Expenses	$3,116,856	$1,769,921	$467,765	$616,985	$71,033	$139,745	$3,719	$47,688
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$26,173,467*	*$8,508,585*	*$3,707,905*	*$11,731,393*	*$1,849,147*	*$251,763*	*$10,946*	*$113,727*
	Working Capital	$3,926,020	$1,276,288	$556,186	$1,759,709	$277,372	$37,764	$1,642	$17,059
	Total Rate Base	$17,525,919	$8,327,305	$2,279,570	$5,301,586	$738,336	$804,807	$18,997	$55,318
	Rate Base Input equals Output								
	Equity Component of Rate Base	$7,010,367	$3,330,922	$911,828	$2,120,634	$295,335	$321,923	$7,599	$22,127
	Net Income on Allocated Assets	$671,593	$22,706	$103,653	$552,136	($56,714)	$58,516	$1,683	($10,387)
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$671,593	$22,706	$103,653	$552,136	($56,714)	$58,516	$1,683	($10,387)
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES STATUS QUO%	100.00%	88.55%	102.60%	133.53%	41.49%	108.32%	113.34%	76.95%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($743,939)	($684,811)	($89,248)	$154,032	($87,399)	($18,241)	($191)	($18,081)
	Deficiency Input equals Output								
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($324,983)	$18,818	$376,472	($79,707)	$20,837	$830	($12,267)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.58%	0.68%	11.37%	26.04%	-19.20%	18.18%	22.15%	-46.94%

Cost Allocation Summary

The discussion and tables above support LUI's proposed reallocation of distribution revenues across customer classes in accordance with Board directions, in order to begin moving toward revenue to cost ratios of 100% and reduce cross-subsidization. LUI submits that the proposed reallocation of distribution revenue is fair and reasonable and customer class revenues will more closely reflect the actual costs of providing distribution service to that class.

Appendix A - OEB Filing Requirement Appendix 2-O Template

Appendix 2-O
Cost Allocation

Please complete the following four tables.

a) Allocated Costs

Classes	Costs Allocated from Previous Study (2008)	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 1,574,342	40.80%	$ 2,838,659	55.32%
GS < 50 kW	$ 474,450	12.29%	$ 723,733	14.10%
GS 50 - 2999 KW	$ 791,120	20.50%	$ 1,122,655	21.88%
GS 3000 - 4999	$ 493,008	12.78%	$ 136,235	2.66%
Street Lighting	$ 482,541	12.50%	$ 250,482	4.88%
Sentinel Lighting	$ 9,841	0.25%	$ 6,222	0.12%
Unmetered Scattered Load (USL)	$ 33,811	0.88%	$ 53,217	1.04%
Total	$ 3,859,113	100.00%	$ 5,131,204	100.00%

Notes

Customer Classification

Host Distributors: Provide information on embedded distributor(s) as a separate class, even if your proposal is to bill the embedded distributor(s) as (a) General Service customer(s).

If proposed rate classes differ from those in place in the previous Cost Allocation study, modify the rate classes to match the current application as closely as possible.

Class Revenue Requirements
If using the Board-issued model, enter data from Worksheet O-1, row 39 in the 2012 model.

For the Embedded Distributor(s), the Service Revenue Requirement does not include Account 4750 - Low Voltage (LV) Costs

Exclude costs in deferral and variance accounts.

Include Smart Meter costs only to the extent that they are being included in Rate Base and Revenue Requirement (i.e. being transferred from accounts 1555 and 1556 as a result of a prudence review).

b) Calculated Class Revenues

Classes (same as previous table)	Column 7B Load Forecast (LF) X current approved rates	Column 7C LF X current approved rates X (1 + d)	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 1,938,972	$ 2,298,799	$ 2,556,790	$ 214,877
GS < 50 kW	$ 582,323	$ 690,388	$ 725,309	$ 52,162
GS 50 - 2999 KW	$ 1,198,646	$ 1,421,087	$ 1,181,345	$ 78,040
GS 3000 - 4999	$ 41,451	$ 49,144	$ 61,414	$ 7,384
Street Lighting	$ 210,576	$ 249,654	$ 178,720	$ 21,666
Sentinel Lighting	$ 5,503	$ 6,524	$ 5,072	$ 528
Unmetered Scattered Load (USL)	$ 31,331	$ 37,145	$ 44,091	$ 3,805
Total	$ 4,008,801	$ 4,752,740	$ 4,752,742	$ 378,462

Notes:

Columns 7B to 7D

LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, **and** kWh or kW, as applicable)

Exclude revenue from rate adders and rate riders. For Embedded Distributor(s): exclude revenue in account 4075.

Columns 7C and 7D:

Column total in each column should equal the Base Revenue Requirement.

For Embedded Distributor(s), Base Revenue Requirement does not include Account 4750 - Low Voltage Costs

Column 7C:

The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

Column 7E:

If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

c) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios Most Recent Year: 2011	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	97.64%	88.55	97.64	85 - 115
GS < 50 kW	107.43%	102.60	107.43	80 - 120
GS 50 - 2999 KW	154.43%	133.53	112.18	80 - 120
GS 3000 - 4999	20.05%	41.49	50.50	80 - 120
Street Lighting	70.00%	108.32	80.00	70 - 120
Sentinel Lighting	70.06%	113.32	90.00	80 - 120
Unmetered Scattered Load (USL)	99.95%	76.95	90.00	80 - 120

Notes:

Previously Approved Revenue-to-Cost Ratios

For most applicants, Most Recent Year would be the third year of the IRM 3 period, e.g. if the applicant rebased in 2008 with further adjustments over 2 years, the Most recent year is 2010.

For applicants that have had rates adjusted only under IRM 2, the Most Recent Year is 2006, and the applicant should enter the ratios from their Informational Filing.

Status Quo Ratios

The Board's updated Cost Allocation Model yields the Status Quo Ratios in Worksheet O-1.

Status Quo means "No Rebalancing" or "Before Rebalancing".

d) Proposed Revenue-to-Cost Ratios

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2012	2013	2014	
	%	%	%	%
Residential	97.64			85 - 115
GS < 50 kW	107.43			80 - 120
GS 50 - 2999 KW	112.18			80 - 120
GS 3000 - 4999	50.50	57.50	65.00	80 - 120
Large User, if applicable				85 - 115
Street Lighting	80.00			70 - 120
Sentinel Lighting	90.00			80 - 120
Unmetered Scattered Load (USL)	90.00			80 - 120
Other class, if applicable				
Embedded distributor, if applicant is a host distributor				

The applicant should complete Table (d) if it is applying for approval of a revenue to cost ratio in 2012 that is outside the Board's policy range for any customer class. Table (d) will show the information that the distributor would likely enter in the IRM model) in 2013. In 2012 Table (d), enter the planned ratios for the classes that will be 'Change' and 'No Change' in 2013 (in the current Revenue Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision – Cost Revenue Adjustment', column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Appendix B – Input Sheets & Output Sheets

2012 COST ALLOCATION
Lakefront Utilities Inc.
EB-2011-0250
Friday, August 26, 2011
Sheet I6.1 Revenue Worksheet - Initial Application

Total kWhs from Load Forecast	250,200,674
Total kWs from Load Forecast	354,633
Deficiency from RRWF	- 743,941
Miscellaneous Revenue	378,462

			1	2	3	5	7	8	9
	ID	Total	Residential	General Service Less Than 50 kW	General Service 50 to 2,999 kW	General Service 3,000 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Billing Data									
Forecast kWh	CEN	250,200,674	73,125,152	35,160,634	120,608,902	19,295,356	1,215,575	78,431	716,623
Forecast kW	CDEM	354,633			303,629	47,442	3,343	218	-
Forecast kW, included in CDEM, of customers receiving line transformer allowance		247,838			200,395	47,442			
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	250,200,674	73,125,152	35,160,634	120,608,902	19,295,356	1,215,575	78,431	716,623
kWh - 30 year weather normalized amount		250,200,674	73,125,152	35,160,634	120,608,902	19,295,356	1,215,575	78,431	716,623
Existing Monthly Charge			$9.29	$22.50	$183.85	$1,766.90	$3.84	$4.66	$11.22
Existing Distribution kWh Rate			$0.0134	$0.0081					$0.03
Existing Distribution kW Rate					$3.4201	$1.0268	$24.3414	$11.47	
Existing TFOA Rate					$0.60	$0.60			
Additional Charges									
Distribution Revenue from Rates		$4,157,505	$1,938,972	$582,323	$1,318,883	$69,917	$210,576	$5,503.40	$31,331.33
Transformer Ownership Allowance		$148,703	$0	$0	$120,237	$28,465	$0		
Net Class Revenue	CREV	$4,008,802	$1,938,972	$582,323	$1,198,646	$41,451	$210,576	$5,503	$31,331
Data Mismatch Analysis									
Revenue with 30 year weather normalized kWh		4,008,802	1,938,972	582,323	1,198,646	41,451	210,576	5,503	31,331

Weather Normalized Data from Hydro One	Total	Residential	General Service Less Than 50 kW	General Service 50 to 2,999 kW	General Service 3,000 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
kWh - 30 year weather normalized amount	250,200,674	73,125,152	35,160,634	120,608,902	19,295,356	1,215,575	78,431	716,623
Loss Factor		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000

2012 COST ALLOCATION
Lakefront Utilities Inc.
EB-2011-0250
Friday, August 26, 2011
Sheet I6.2 Customer Data Worksheet - Initial Application

			1	2	3	5	7	8	9
	ID	Total	Residential	General Service Less Than 50 kW	General Service 50 to 2,999 kW	General Service 3,000 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Billing Data									
Bad Debt 3 Year Historical Average	BDHA	$50,000	$40,000	$10,000	$0	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$63,140	$36,080	$9,020	$18,040				
Number of Bills	CNB	65,746	52,704	9,912	1,525	12	24	648	921
Number of Devices							2,804	54	77
Number of Connections (Unmetered)	CCON	2,519	-	-	-	-	2,389	54	77
Total Number of Customers	CCA	9,966	8,603	1,102	127	1	2	54	77
Bulk Customer Base	CCB		-	-	-	-	-	-	-
Primary Customer Base	CCP	9,966	8,603	1,102	127	1	2	54	77
Line Transformer Customer Base	CCLT	9,880	8,603	1,102	42	-	2	54	77
Secondary Customer Base	CCS	9,958	8,603	1,102	119	1	2	54	77
Weighted - Services	CWCS	14,526	8,603	2,204	1,190	10	2,389	54	77
Weighted Meter -Capital	CWMC	2,765,738	2,365,904	303,031	85,803	11,000	-	-	-
Weighted Meter Reading	CWMR	74,088	52,704	9,912	10,884	588	-	-	-
Weighted Bills	CWNB	87,983	52,704	19,824	10,678	84	24	65	4,605

Bad Debt Data

Historic Year:	2009	50,000	40,000	10,000					
Historic Year:	2010	50,000	40,000	10,000					
Historic Year:	2011	50,000	40,000	10,000					
Three-year average		**50,000**	**40,000**	**10,000**	-	-	-	-	-

2012 COST ALLOCATION
Lakefront Utilities Inc.
EB-2011-0250
Friday, August 26, 2011
Sheet I8 Demand Data Worksheet - Initial Application

This is an input sheet for demand allocators.

CP TEST RESULTS	12 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 Residential	2 General Service Less Than 50 kW	3 General Service 50 to 2,999 kW	5 General Service 3,000 to 4,999 kW	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load
CO-INCIDENT PEAK									
1 CP									
Transformation CP	TCP1	42,297	15,643	6,110	17,843	2,306	272	18	106
Bulk Delivery CP	BCP1	42,297	15,643	6,110	17,843	2,306	272	18	106
Total Sytem CP	DCP1	42,297	15,643	6,110	17,843	2,306	272	18	106
4 CP									
Transformation CP	TCP4	164,255	58,497	22,581	74,099	8,063	616	40	359
Bulk Delivery CP	BCP4	164,255	58,497	22,581	74,099	8,063	616	40	359
Total Sytem CP	DCP4	164,255	58,497	22,581	74,099	8,063	616	40	359
12 CP									
Transformation CP	TCP12	446,879	149,585	57,847	212,058	25,473	893	57	965
Bulk Delivery CP	BCP12	446,879	149,585	57,847	212,058	25,473	893	57	965
Total Sytem CP	DCP12	446,879	149,585	57,847	212,058	25,473	893	57	965
NON CO_INCIDENT PEAK									
1 NCP									
Classification NCP from Load Data Provider	DNCP1	49,404	18,309	6,836	20,729	3,129	277	18	106
Primary NCP	PNCP1	49,404	18,309	6,836	20,729	3,129	277	18	106
Line Transformer NCP	LTNCP1	32,401	18,309	6,836	6,855	-	277	18	106
Secondary NCP	SNCP1	48,081	18,309	6,836	19,406	3,129	277	18	106
4 NCP									
Classification NCP from Load Data Provider	DNCP4	190,841	70,596	25,285	81,380	12,018	1,107	71	384
Primary NCP	PNCP4	190,841	70,596	25,285	81,380	12,018	1,107	71	384
Line Transformer NCP	LTNCP4	124,356	70,596	25,285	26,913	-	1,107	71	384
Secondary NCP	SNCP4	185,646	70,596	25,285	76,185	12,018	1,107	71	384
12 NCP									
Classification NCP from Load Data Provider	DNCP12	508,803	174,822	65,215	231,093	33,162	3,290	212	1,009
Primary NCP	PNCP12	508,803	174,822	65,215	231,093	33,162	3,290	212	1,009
Line Transformer NCP	LTNCP12	320,973	174,822	65,215	76,424	-	3,290	212	1,009
Secondary NCP	SNCP12	494,050	174,822	65,215	216,340	33,162	3,290	212	1,009

2012 COST ALLOCATION
Lakefront Utilities Inc.
EB-2011-0250
Friday, August 26, 2011
Sheet O1 Revenue to Cost Summary Worksheet - Initial Application

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 Residential	2 General Service Less Than 50 kW	3 General Service 50 to 2,999 kW	5 General Service 3,000 to 4,999 kW	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$4,008,802	$1,938,972	$582,323	$1,198,646	$41,451	$210,576	$5,503	$31,331
mi	Miscellaneous Revenue (mi)	$378,462	$214,877	$52,162	$78,040	$7,384	$21,666	$528	$3,805
		Miscellaneous Revenue Input equals Output							
	Total Revenue at Existing Rates	$4,387,264	$2,153,848	$634,485	$1,276,686	$48,836	$232,241	$6,031	$35,136
	Factor required to recover deficiency (1 + D)	1.1856							
	Distribution Revenue at Status Quo Rates	$4,752,741	$2,298,799	$690,388	$1,421,087	$49,144	$249,654	$6,525	$37,146
	Miscellaneous Revenue (mi)	$378,462	$214,877	$52,162	$78,040	$7,384	$21,666	$528	$3,805
	Total Revenue at Status Quo Rates	$5,131,204	$2,513,676	$742,550	$1,499,127	$56,528	$271,319	$7,053	$40,950
	Expenses								
di	Distribution Costs (di)	$1,045,524	$508,927	$131,568	$282,539	$38,435	$78,719	$1,769	$3,566
cu	Customer Related Costs (cu)	$725,956	$499,175	$135,303	$65,418	$1,473	$141	$340	$24,106
ad	General and Administration (ad)	$1,345,376	$761,819	$200,894	$269,027	$31,125	$60,885	$1,610	$20,016
dep	Depreciation and Amortization (dep)	$816,209	$448,451	$104,619	$192,282	$24,183	$43,516	$983	$2,175
INPUT	PILs (INPUT)	$35,198	$18,222	$4,446	$9,206	$1,205	$1,975	$45	$99
INT	Interest	$491,348	$254,375	$62,067	$128,518	$16,822	$27,567	$624	$1,376
	Total Expenses	$4,459,610	$2,490,970	$638,897	$946,991	$113,242	$212,803	$5,370	$51,337
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$671,593	$347,690	$84,835	$175,664	$22,992	$37,679	$853	$1,880
	Revenue Requirement (includes NI)	$5,131,204	$2,838,659	$723,733	$1,122,655	$136,235	$250,482	$6,222	$53,217
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$22,665,380	$11,706,492	$3,005,932	$5,811,691	$713,881	$1,330,154	$30,015	$67,214
gp	General Plant - Gross	$1,937,453	$1,017,987	$252,708	$484,334	$59,552	$114,586	$2,590	$5,696
accum dep	Accumulated Depreciation	($8,695,275)	($4,341,135)	($1,170,404)	($2,356,925)	($295,833)	($494,162)	($11,125)	($25,692)
co	Capital Contribution	($2,307,659)	($1,332,327)	($364,852)	($397,224)	($16,636)	($183,536)	($4,125)	($8,958)
	Total Net Plant	$13,599,899	$7,051,017	$1,723,384	$3,541,877	$460,964	$767,042	$17,355	$38,259
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$23,056,611	$6,738,664	$3,240,139	$11,114,409	$1,778,115	$112,018	$7,228	$66,039
	OM&A Expenses	$3,116,856	$1,769,921	$467,765	$616,985	$71,033	$139,745	$3,719	$47,688
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$26,173,467***	***$8,508,585***	***$3,707,905***	***$11,731,393***	***$1,849,147***	***$251,763***	***$10,946***	***$113,727***
	Working Capital	$3,926,020	$1,276,288	$556,186	$1,759,709	$277,372	$37,764	$1,642	$17,059
	Total Rate Base	$17,525,919	$8,327,305	$2,279,570	$5,301,586	$738,336	$804,807	$18,997	$55,318
		Rate Base Input equals Output							
	Equity Component of Rate Base	$7,010,367	$3,330,922	$911,828	$2,120,634	$295,335	$321,923	$7,599	$22,127
	Net Income on Allocated Assets	$671,593	$22,706	$103,653	$552,136	($56,714)	$58,516	$1,683	($10,387)
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$671,593	$22,706	$103,653	$552,136	($56,714)	$58,516	$1,683	($10,387)
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES STATUS QUO%	100.00%	88.55%	102.60%	133.53%	41.49%	108.32%	113.34%	76.95%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($743,939)	($684,811)	($89,248)	$154,032	($87,399)	($18,241)	($191)	($18,081)
		Deficiency Input equals Output							
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($324,983)	$18,818	$376,472	($79,707)	$20,837	$830	($12,267)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.58%	0.68%	11.37%	26.04%	-19.20%	18.18%	22.15%	-46.94%

2012 COST ALLOCATION
Lakefront Utilities Inc.
EB-2011-0250
Friday, August 26, 2011
Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Initial Application

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1 Residential	2 General Service Less Than 50 kW	3 General Service 50 to 2,999 kW	5 General Service 3,000 to 4,999 kW	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$5.28	$7.90	$19.08	$168.30	-$0.02	$0.28	$14.85
Customer Unit Cost per month - Directly Related	$8.36	$13.27	$41.21	$266.81	-$0.02	$0.51	$25.77
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$17.91	$27.55	$80.01	$305.79	$8.70	$9.59	$52.02
Existing Approved Fixed Charge	$9.29	$22.50	$183.85	$1,766.90	$3.84	$4.66	$11.22

Information to be Used to Allocate PILs, ROD, ROE and A&G

	Total	1 Residential	2 General Service Less Than 50 kW	3 General Service 50 to 2,999 kW	5 General Service 3,000 to 4,999 kW	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load
General Plant - Gross Assets	$1,937,453	$1,017,987	$252,708	$484,334	$59,552	$114,586	$2,590	$5,696
General Plant - Accumulated Depreciation	($611,873)	($321,494)	($79,809)	($152,959)	($18,807)	($36,188)	($818)	($1,799)
General Plant - Net Fixed Assets	$1,325,580	$696,493	$172,899	$331,375	$40,745	$78,398	$1,772	$3,897
General Plant - Depreciation	$264,064	$138,746	$34,443	$66,012	$8,117	$15,617	$353	$776
Total Net Fixed Assets Excluding General Plant	$12,274,319	$6,354,524	$1,550,485	$3,210,502	$420,219	$688,644	$15,583	$34,362
Total Administration and General Expense	$1,345,376	$761,819	$200,894	$269,027	$31,125	$60,885	$1,610	$20,016
Total O&M	$1,771,480	$1,008,102	$266,872	$347,958	$39,908	$78,860	$2,109	$27,672

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 General Service Less Than 50 kW	3 General Service 50 to 2,999 kW	5 General Service 3,000 to 4,999 kW	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load
	Distribution Plant								
1860	Meters	$2,072,905	$1,773,232	$227,120	$64,309	$8,244	$0	$0	$0
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant - Meters only	($467,580)	($399,983)	($51,231)	($14,506)	($1,860)	$0	$0	$0
	Meter Net Fixed Assets	**$1,605,326**	**$1,373,249**	**$175,889**	**$49,803**	**$6,385**	**$0**	**$0**	**$0**
	Misc Revenue								
4082	Retail Services Revenues	($9,985)	($5,670)	($1,499)	($1,977)	($228)	($448)	($12)	($153)
4084	Service Transaction Requests (STR) Revenues	($4,015)	($2,280)	($603)	($795)	($92)	($180)	($5)	($61)
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($63,140)	($36,080)	($9,020)	($18,040)	$0	$0	$0	$0
	Sub-total	*($77,140)*	*($44,030)*	*($11,121)*	*($20,811)*	*($319)*	*($628)*	*($17)*	*($214)*
	Operation								
5065	Meter Expense	$31,316	$26,789	$3,431	$972	$125	$0	$0	$0
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$77	$54	$7	$1	$0	$15	$0	$0
	Sub-total	*$31,393*	*$26,843*	*$3,438*	*$972*	*$125*	*$15*	*$0*	*$0*
	Maintenance								
5175	Maintenance of Meters	$194,264	$166,180	$21,285	$6,027	$773	$0	$0	$0
	Billing and Collection								
5310	Meter Reading Expense	$17,192	$12,230	$2,300	$2,526	$136	$0	$0	$0
5315	Customer Billing	$131,000	$78,472	$29,516	$15,898	$125	$36	$96	$6,856
5320	Collecting	$130,277	$78,039	$29,353	$15,810	$124	$36	$96	$6,819
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$4,172	$2,499	$940	$506	$4	$1	$3	$218
	Sub-total	$282,641	$171,240	$62,110	$34,740	$390	$72	$196	$13,893
	Total Operation, Maintenance and Billing	$508,299	$364,262	$86,833	$41,740	$1,287	$87	$196	$13,894
	Amortization Expense - Meters	$121,538	$103,967	$13,316	$3,771	$483	$0	$0	$0
	Allocated PILs	$4,149	$3,549	$454	$129	$17	$0	$0	$0
	Allocated Debt Return	$57,917	$49,542	$6,335	$1,807	$233	$0	$0	$0
	Allocated Equity Return	$79,163	$67,716	$8,658	$2,470	$318	$0	$0	$0
	Total	**$693,924**	**$545,006**	**$104,475**	**$29,105**	**$2,020**	**($540)**	**$179**	**$13,680**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

			1	2	3	5	7	8	9
USoA Account #	**Accounts**	**Total**	**Residential**	**General Service Less Than 50 kW**	**General Service 50 to 2,999 kW**	**General Service 3,000 to 4,999 kW**	**Street Lighting**	**Sentinel Lighting**	**Unmetered Scattered Load**
	Distribution Plant								
1860	Meters	$2,072,905	$1,773,232	$227,120	$64,309	$8,244	$0	$0	$0
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant - Meters only	($467,580)	($399,983)	($51,231)	($14,506)	($1,860)	$0	$0	$0
	Meter Net Fixed Assets	$1,605,326	$1,373,249	$175,889	$49,803	$6,385	$0	$0	$0
	Allocated General Plant Net Fixed Assets	$175,890	$150,516	$19,614	$5,140	$619	$0	$0	$0
	Meter Net Fixed Assets Including General Plant	$1,781,215	$1,523,765	$195,503	$54,943	$7,004	$0	$0	$0
	Misc Revenue								
4082	Retail Services Revenues	($9,985)	($5,670)	($1,499)	($1,977)	($228)	($448)	($12)	($153)
4084	Service Transaction Requests (STR) Revenues	($4,015)	($2,280)	($603)	($795)	($92)	($180)	($5)	($61)
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($63,140)	($36,080)	($9,020)	($18,040)	$0	$0	$0	$0
	Sub-total	*($77,140)*	*($44,030)*	*($11,121)*	*($20,811)*	*($319)*	*($628)*	*($17)*	*($214)*
	Operation								
5065	Meter Expense	$31,316	$26,789	$3,431	$972	$125	$0	$0	$0
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$77	$54	$7	$1	$0	$15	$0	$0
	Sub-total	*$31,393*	*$26,843*	*$3,438*	*$972*	*$125*	*$15*	*$0*	*$0*
	Maintenance								
5175	Maintenance of Meters	$194,264	$166,180	$21,285	$6,027	$773	$0	$0	$0
	Billing and Collection								
5310	Meter Reading Expense	$17,192	$12,230	$2,300	$2,526	$136	$0	$0	$0
5315	Customer Billing	$131,000	$78,472	$29,516	$15,898	$125	$36	$96	$6,856
5320	Collecting	$130,277	$78,039	$29,353	$15,810	$124	$36	$96	$6,819
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$4,172	$2,499	$940	$506	$4	$1	$3	$218
	Sub-total	*$282,641*	*$171,240*	*$62,110*	*$34,740*	*$390*	*$72*	*$196*	*$13,893*
	Total Operation, Maintenance and Billing	$508,299	$364,262	$86,833	$41,740	$1,287	$87	$196	$13,894
	Amortization Expense - Meters	$121,538	$103,967	$13,316	$3,771	$483	$0	$0	$0
	Amortization Expense - General Plant assigned to Meters	*$35,038*	*$29,984*	*$3,907*	*$1,024*	*$123*	*$0*	*$0*	*$0*
	Admin and General	$384,179	$275,272	$65,365	$32,271	$1,004	$67	$149	$10,050
	Allocated PILs	$4,603	$3,938	$504	$143	$18	$0	$0	$0
	Allocated Debt Return	$64,262	$54,972	$7,041	$1,994	$256	$0	$0	$0
	Allocated Equity Return	$87,836	$75,138	$9,624	$2,725	$349	$0	$0	$0
	Total	**$1,128,615**	**$863,503**	**$175,469**	**$62,855**	**$3,202**	**($473)**	**$329**	**$23,730**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

			1	2	3	5	7	8	9
USoA Account #	Accounts	Total	Residential	General Service Less Than 50 kW	General Service 50 to 2,999 kW	General Service 3,000 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
	Distribution Plant								
1565	Conservation and Demand Management Expenditures and Recoveries	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$554,251	$386,014	$49,446	$5,698	$45	$107,194	$2,409	$3,444
1830-5	Poles, Towers and Fixtures - Secondary	$116,674	$81,311	$10,416	$1,125	$9	$22,580	$508	$725
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$1,426,924	$993,797	$127,300	$14,671	$116	$275,971	$6,203	$8,866
1835-5	Overhead Conductors and Devices - Secondary	$300,378	$209,337	$26,815	$2,896	$24	$58,132	$1,307	$1,868
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$471,220	$328,186	$42,039	$4,845	$38	$91,135	$2,048	$2,928
1840-5	Underground Conduit - Secondary	$52,358	$36,489	$4,674	$505	$4	$10,133	$228	$326
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$490,585	$341,673	$43,767	$5,044	$40	$94,881	$2,133	$3,048
1845-5	Underground Conductors and Devices - Secondary	$735,877	$512,842	$65,692	$7,094	$60	$142,413	$3,201	$4,575
1850	Line Transformers	$2,178,820	$1,528,102	$195,742	$7,460	$0	$424,345	$9,538	$13,633
1855	Services	$611,529	$362,166	$92,783	$50,096	$421	$100,571	$2,261	$3,231
1860	Meters	$2,072,905	$1,773,232	$227,120	$64,309	$8,244	$0	$0	$0
1880	IFRS Placeholder Asset Account	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$9,011,519*	*$6,553,149*	*$885,795*	*$163,742*	*$9,001*	*$1,327,354*	*$29,835*	*$42,643*
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($3,802,988)	($2,708,997)	($362,982)	($52,668)	($2,130)	($641,199)	($14,412)	($20,599)
	Customer Related Net Fixed Assets	$5,208,531	$3,844,152	$522,813	$111,074	$6,872	$686,155	$15,423	$22,044
	Allocated General Plant Net Fixed Assets	$574,142	$421,342	$58,301	$11,465	$666	$78,115	$1,754	$2,500
	Customer Related NFA Including General Plant	$5,782,672	$4,265,493	$581,113	$122,538	$7,538	$764,269	$17,177	$24,544
	Misc Revenue								
4082	Retail Services Revenues	($9,985)	($5,670)	($1,499)	($1,977)	($228)	($448)	($12)	($153)
4084	Service Transaction Requests (STR) Revenues	($4,015)	($2,280)	($603)	($795)	($92)	($180)	($5)	($61)
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($63,140)	($36,080)	($9,020)	($18,040)	$0	$0	$0	$0
4235	Miscellaneous Service Revenues	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*($77,140)*	*($44,030)*	*($11,121)*	*($20,811)*	*($319)*	*($628)*	*($17)*	*($214)*
	Operating and Maintenance								
5005	Operation Supervision and Engineering	$129,471	$89,191	$12,291	$1,855	$14	$24,768	$557	$796
5010	Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	$123,990	$86,364	$11,063	$1,261	$10	$23,983	$539	$770
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$50,465	$35,151	$4,503	$513	$4	$9,761	$219	$314
5035	Overhead Distribution Transformers- Operation	$252	$177	$23	$1	$0	$49	$1	$2
5040	Underground Distribution Lines and Feeders - Operation Labour	$10,000	$6,967	$892	$100	$1	$1,935	$43	$62
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$7,973	$5,555	$712	$80	$1	$1,542	$35	$50
5055	Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0	$0
5065	Meter Expense	$31,316	$26,789	$3,431	$972	$125	$0	$0	$0
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$77	$54	$7	$1	$0	$15	$0	$0
5085	Miscellaneous Distribution Expense	$1,877	$1,293	$178	$27	$0	$359	$8	$12
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$20,925	$14,415	$1,986	$300	$2	$4,003	$90	$129
5120	Maintenance of Poles, Towers and Fixtures	$16,715	$11,642	$1,491	$170	$1	$3,233	$73	$104
5125	Maintenance of Overhead Conductors and Devices	$4,000	$2,786	$357	$41	$0	$774	$17	$25
5130	Maintenance of Overhead Services	$3,000	$1,777	$455	$246	$2	$493	$11	$16
5135	Overhead Distribution Lines and Feeders - Right of Way	$18,022	$12,553	$1,608	$183	$1	$3,486	$78	$112
5145	Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
5150	Maintenance of Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0
5155	Maintenance of Underground Services	$9,229	$5,466	$1,400	$756	$6	$1,518	$34	$49
5160	Maintenance of Line Transformers	$14,456	$10,138	$1,299	$49	$0	$2,815	$63	$90
5175	Maintenance of Meters	$194,264	$166,180	$21,285	$6,027	$773	$0	$0	$0
	Sub-total	*$636,033*	*$476,497*	*$62,980*	*$12,581*	*$941*	*$78,734*	*$1,770*	*$2,529*
	Billing and Collection								
5305	Supervision	$0	$0	$0	$0	$0	$0	$0	$0
5310	Meter Reading Expense	$17,192	$12,230	$2,300	$2,526	$136	$0	$0	$0
5315	Customer Billing	$131,000	$78,472	$29,516	$15,898	$125	$36	$96	$6,856
5320	Collecting	$130,277	$78,039	$29,353	$15,810	$124	$36	$96	$6,819
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$4,172	$2,499	$940	$506	$4	$1	$3	$218
5335	Bad Debt Expense	$22,545	$18,036	$4,509	$0	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$195,112	$116,877	$43,962	$23,679	$186	$53	$144	$10,212
	Sub-total	*$500,298*	*$306,152*	*$110,580*	*$58,419*	*$576*	*$126*	*$339*	*$24,106*
	Sub Total Operating, Maintenance and Biling	*$1,136,331*	*$782,649*	*$173,561*	*$71,000*	*$1,517*	*$78,860*	*$2,109*	*$26,635*
	Amortization Expense - Customer Related	$266,447	$204,212	$26,795	$5,586	$497	$27,837	$626	$894
	Amortization Expense - General Plant assigned to Meters	$114,373	$83,934	$11,614	$2,284	$133	$15,561	$349	$498
	Admin and General	$859,937	$591,446	$130,652	$54,895	$1,183	$60,885	$1,610	$19,266
	Allocated PILs	$14,936	$11,024	$1,499	$319	$20	$1,968	$44	$63
	Allocated Debt Return	$208,500	$153,884	$20,928	$4,446	$275	$27,467	$617	$882
	Allocated Equity Return	$284,986	$210,334	$28,606	$6,077	$376	$37,543	$844	$1,206
	PLCC Adjustment for Line Transformer	$38,507	$33,718	$4,324	$164	$0	$0	$0	$301
	PLCC Adjustment for Primary Costs	$88,814	$77,099	$9,880	$1,142	$9	$0	$0	$684
	PLCC Adjustment for Secondary Costs	$38,832	$34,066	$3,982	$442	$3	$0	$0	$338
	Total	$2,642,217	**$1,848,568**	**$364,348**	**$122,048**	**$3,669**	**$249,493**	**$6,183**	**$47,908**

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	General Service Less Than 50 kW	General Service 50 to 2,999 kW	General Service 3,000 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Distribution Plant								
CWMC	$ 2,072,905	$ 1,773,232	$ 227,120	$ 64,309	$ 8,244	$ -	$ -	$ -
Accumulated Amortization								
Accum. Amortization of Electric Utility Plant - Meters only	$ (467,580)	$ (399,983)	$ (51,231)	$ (14,506)	$ (1,860)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 1,605,326	$ 1,373,249	$ 175,889	$ 49,803	$ 6,385	$ -	$ -	$ -
Misc Revenue								
CWNB	$ (14,000)	$ (7,950)	$ (2,101)	$ (2,771)	$ (319)	$ (628)	$ (17)	$ (214)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (63,140)	$ (36,080)	$ (9,020)	$ (18,040)	$ -	$ -	$ -	$ -
Sub-total	$ (77,140)	$ (44,030)	$ (11,121)	$ (20,811)	$ (319)	$ (628)	$ (17)	$ (214)
Operation								
CWMC	$ 31,316	$ 26,789	$ 3,431	$ 972	$ 125	$ -	$ -	$ -
CCA	$ 77	$ 54	$ 7	$ 1	$ 0	$ 15	$ 0	$ 0
Sub-total	$ 31,393	$ 26,843	$ 3,438	$ 972	$ 125	$ 15	$ 0	$ 0
Maintenance								
1860	$ 194,264	$ 166,180	$ 21,285	$ 6,027	$ 773	$ -	$ -	$ -
Billing and Collection								
CWMR	$ 17,192	$ 12,230	$ 2,300	$ 2,526	$ 136	$ -	$ -	$ -
CWNB	$ 265,449	$ 159,010	$ 59,810	$ 32,215	$ 253	$ 72	$ 196	$ 13,893
Sub-total	$ 282,641	$ 171,240	$ 62,110	$ 34,740	$ 390	$ 72	$ 196	$ 13,893
Total Operation, Maintenance and Billing	$ 508,299	$ 364,262	$ 86,833	$ 41,740	$ 1,287	$ 87	$ 196	$ 13,894
Amortization Expense - Meters	$ 121,538	$ 103,967	$ 13,316	$ 3,771	$ 483	$ -	$ -	$ -
Allocated PILs	$ 4,149	$ 3,549	$ 454	$ 129	$ 17	$ -	$ -	$ -
Allocated Debt Return	$ 57,917	$ 49,542	$ 6,335	$ 1,807	$ 233	$ -	$ -	$ -
Allocated Equity Return	$ 79,163	$ 67,716	$ 8,658	$ 2,470	$ 318	$ -	$ -	$ -
Total	**$ 693,924**	**$ 545,006**	**$ 104,475**	**$ 29,105**	**$ 2,020**	**$ (540)**	**$ 179**	**$ 13,680**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	General Service Less Than 50 kW	General Service 50 to 2,999 kW	General Service 3,000 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Distribution Plant								
CWMC	$ 2,072,905	$ 1,773,232	$ 227,120	$ 64,309	$ 8,244	$ -	$ -	$ -
Accumulated Amortization								
Accum. Amortization of Electric Utility Plant - Meters only	$ (467,580)	$ (399,983)	$ (51,231)	$ (14,506)	$ (1,860)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 1,605,326	$ 1,373,249	$ 175,889	$ 49,803	$ 6,385	$ -	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 175,890	$ 150,516	$ 19,614	$ 5,140	$ 619	$ -	$ -	$ -
Meter Net Fixed Assets Including General Plant	$ 1,781,215	$ 1,523,765	$ 195,503	$ 54,943	$ 7,004	$ -	$ -	$ -
Misc Revenue								
CWNB	$ (14,000)	$ (7,950)	$ (2,101)	$ (2,771)	$ (319)	$ (628)	$ (17)	$ (214)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (63,140)	$ (36,080)	$ (9,020)	$ (18,040)	$ -	$ -	$ -	$ -
Sub-total	*$ (77,140)*	*$ (44,030)*	*$ (11,121)*	*$ (20,811)*	*$ (319)*	*$ (628)*	*$ (17)*	*$ (214)*
Operation								
CWMC	$ 31,316	$ 26,789	$ 3,431	$ 972	$ 125	$ -	$ -	$ -
CCA	$ 77	$ 54	$ 7	$ 1	$ 0	$ 15	$ 0	$ 0
Sub-total	*$ 31,393*	*$ 26,843*	*$ 3,438*	*$ 972*	*$ 125*	*$ 15*	*$ 0*	*$ 0*
Maintenance								
1860	$ 194,264	$ 166,180	$ 21,285	$ 6,027	$ 773	$ -	$ -	$ -
Billing and Collection								
CWMR	$ 17,192	$ 12,230	$ 2,300	$ 2,526	$ 136	$ -	$ -	$ -
CWNB	$ 265,449	$ 159,010	$ 59,810	$ 32,215	$ 253	$ 72	$ 196	$ 13,893
Sub-total	*$ 282,641*	*$ 171,240*	*$ 62,110*	*$ 34,740*	*$ 390*	*$ 72*	*$ 196*	*$ 13,893*
Total Operation, Maintenance and Billing	$ 508,299	$ 364,262	$ 86,833	$ 41,740	$ 1,287	$ 87	$ 196	$ 13,894
Amortization Expense - Meters	$ 121,538	$ 103,967	$ 13,316	$ 3,771	$ 483	$ -	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 35,038	$ 29,984	$ 3,907	$ 1,024	$ 123	$ -	$ -	$ -
Admin and General	$ 384,179	$ 275,272	$ 65,365	$ 32,271	$ 1,004	$ 67	$ 149	$ 10,050
Allocated PILs	$ 4,603	$ 3,938	$ 504	$ 143	$ 18	$ -	$ -	$ -
Allocated Debt Return	$ 64,262	$ 54,972	$ 7,041	$ 1,994	$ 256	$ -	$ -	$ -
Allocated Equity Return	$ 87,836	$ 75,138	$ 9,624	$ 2,725	$ 349	$ -	$ -	$ -
Total	**$ 1,128,615**	**$ 863,503**	**$ 175,469**	**$ 62,855**	**$ 3,202**	**$ (473)**	**$ 329**	**$ 23,730**

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Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	General Service Less Than 50 kW	General Service 50 to 2,999 kW	General Service 3,000 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
	Distribution Plant								
	CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 2,942,979	$ 2,049,670	$ 262,552	$ 30,258	$ 238	$ 569,181	$ 12,794	$ 18,286
	SNCP	$ 1,205,286	$ 839,979	$ 107,597	$ 11,619	$ 98	$ 233,257	$ 5,243	$ 7,494
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 2,178,820	$ 1,528,102	$ 195,742	$ 7,460	$ -	$ 424,345	$ 9,538	$ 13,633
	CWCS	$ 611,529	$ 362,166	$ 92,783	$ 50,096	$ 421	$ 100,571	$ 2,261	$ 3,231
	CWMC	$ 2,072,905	$ 1,773,232	$ 227,120	$ 64,309	$ 8,244	$ -	$ -	$ -
	Sub-total	*$ 9,011,519*	*$ 6,553,149*	*$ 885,795*	*$ 163,742*	*$ 9,001*	*$ 1,327,354*	*$ 29,835*	*$ 42,643*
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (3,802,988)	$ (2,708,997)	$ (362,982)	$ (52,668)	$ (2,130)	$ (641,199)	$ (14,412)	$ (20,599)
	Customer Related Net Fixed Assets	$ 5,208,531	$ 3,844,152	$ 522,813	$ 111,074	$ 6,872	$ 686,155	$ 15,423	$ 22,044
	Allocated General Plant Net Fixed Assets	$ 574,142	$ 421,342	$ 58,301	$ 11,465	$ 666	$ 78,115	$ 1,754	$ 2,500
	Customer Related NFA Including General Plant	$ 5,782,672	$ 4,265,493	$ 581,113	$ 122,538	$ 7,538	$ 764,269	$ 17,177	$ 24,544
	Misc Revenue								
	CWNB	$ (14,000)	$ (7,950)	$ (2,101)	$ (2,771)	$ (319)	$ (628)	$ (17)	$ (214)
	NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LPHA	$ (63,140)	$ (36,080)	$ (9,020)	$ (18,040)	$ -	$ -	$ -	$ -
	Sub-total	*$ (77,140)*	*$ (44,030)*	*$ (11,121)*	*$ (20,811)*	*$ (319)*	*$ (628)*	*$ (17)*	*$ (214)*
	Operating and Maintenance								
	1815-1855	$ 152,274	$ 104,899	$ 14,455	$ 2,182	$ 17	$ 29,130	$ 655	$ 936
	1830 & 1835	$ 192,477	$ 134,068	$ 17,173	$ 1,957	$ 16	$ 37,230	$ 837	$ 1,196
	1850	$ 14,708	$ 10,315	$ 1,321	$ 50	$ -	$ 2,864	$ 64	$ 92
	1840 & 1845	$ 17,973	$ 12,521	$ 1,604	$ 180	$ 1	$ 3,477	$ 78	$ 112
	CWMC	$ 31,316	$ 26,789	$ 3,431	$ 972	$ 125	$ -	$ -	$ -
	CCA	$ 77	$ 54	$ 7	$ 1	$ 0	$ 15	$ 0	$ 0
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1830	$ 16,715	$ 11,642	$ 1,491	$ 170	$ 1	$ 3,233	$ 73	$ 104
	1835	$ 4,000	$ 2,786	$ 357	$ 41	$ 0	$ 774	$ 17	$ 25
	1855	$ 12,229	$ 7,242	$ 1,855	$ 1,002	$ 8	$ 2,011	$ 45	$ 65
	1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1845	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1860	$ 194,264	$ 166,180	$ 21,285	$ 6,027	$ 773	$ -	$ -	$ -
	Sub-total	*$ 636,033*	*$ 476,497*	*$ 62,980*	*$ 12,581*	*$ 941*	*$ 78,734*	*$ 1,770*	*$ 2,529*
	Billing and Collection								
	CWNB	$ 460,561	$ 275,886	$ 103,771	$ 55,894	$ 440	$ 126	$ 339	$ 24,106
	CWMR	$ 17,192	$ 12,230	$ 2,300	$ 2,526	$ 136	$ -	$ -	$ -
	BDHA	$ 22,545	$ 18,036	$ 4,509	$ -	$ -	$ -	$ -	$ -
	Sub-total	*$ 500,298*	*$ 306,152*	*$ 110,580*	*$ 58,419*	*$ 576*	*$ 126*	*$ 339*	*$ 24,106*
	Sub Total Operating, Maintenance and Biling	*$ 1,136,331*	*$ 782,649*	*$ 173,561*	*$ 71,000*	*$ 1,517*	*$ 78,860*	*$ 2,109*	*$ 26,635*
	Amortization Expense - Customer Related	$ 266,447	$ 204,212	$ 26,795	$ 5,586	$ 497	$ 27,837	$ 626	$ 894
	Amortization Expense - General Plant assigned to Meters	$ 114,373	$ 83,934	$ 11,614	$ 2,284	$ 133	$ 15,561	$ 349	$ 498
	Admin and General	$ 859,937	$ 591,446	$ 130,652	$ 54,895	$ 1,183	$ 60,885	$ 1,610	$ 19,266
	Allocated PILs	$ 14,936	$ 11,024	$ 1,499	$ 319	$ 20	$ 1,968	$ 44	$ 63
	Allocated Debt Return	$ 208,500	$ 153,884	$ 20,928	$ 4,446	$ 275	$ 27,467	$ 617	$ 882
	Allocated Equity Return	$ 284,986	$ 210,334	$ 28,606	$ 6,077	$ 376	$ 37,543	$ 844	$ 1,206
	PLCC Adjustment for Line Transformer	$ 38,507	$ 33,718	$ 4,324	$ 164	$ -	$ -	$ -	$ 301
	PLCC Adjustment for Primary Costs	$ 88,814	$ 77,099	$ 9,880	$ 1,142	$ 9	$ -	$ -	$ 684
	PLCC Adjustment for Secondary Costs	$ 38,832	$ 34,066	$ 3,982	$ 442	$ 3	$ -	$ -	$ 338
	Total	**$ 2,642,217**	**$ 1,848,568**	**$ 364,348**	**$ 122,048**	**$ 3,669**	**$ 249,493**	**$ 6,183**	**$ 47,908**

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RATE DESIGN OVERVIEW

This Exhibit provides the calculation and rationale for LUI's proposed distribution rates, by rate class for the 2012 Test Year, based on the rate design as proposed in this Exhibit.

LUI's total 2012 service revenue requirement has been calculated to be $ 5,104,349 . The total revenue offsets of $ 378,462 will reduce LUI's total service revenue requirement to a net base revenue requirement of $ 4,725,887 . The base revenue requirement is used to determine the proposed distribution rates by rate class and is derived from LUI's 2012 capital and operating forecasts, weather normalized electricity consumption, forecasted customer counts, and regulated return on rate base. The revenue requirements are summarized below in Table 8-0:

Table 8-0 Calculation of Base Revenue Requirement

OM&A Expenses	3,116,856
Amortization Expenses	816,209
Total Distribution Expenses	**3,933,064**
Regulated Return On Capital	1,162,941
PILs	35,198
Service Revenue Requirement	**5,131,204**
Service Revenue Requirement	5,131,204
Less: Revenue Offsets	378,462
Base Revenue Requirement	**4,752,741**

Service Revenue Requirement	**$**	**5,131,204**
Less: Revenue Offsets	**$**	**378,462**
Total Base Revenue Requirement	**$**	**4,752,741**
Addback LV Charges	**$**	**313,691**
Addback Transformer Allowances	**$**	**148,703**
Gross Revenues For Rates	**$**	**5,215,135**

ALLOCATION OF BASE REVENUE REQUIREMENT

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 Table 8-1 shows how the based revenue requirement has been allocated to the rate classes.

Table 8-1 Proposed Apportionment of Base Revenue Requirement

Class	Revenue Requirement - 2012 Cost Allocation Model Line 35 from O1 in CA	2012 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2012 Cost Allocation Model - Line 19 from O1 in CA	Total Revenue	Revenue Cost Ratio	Check Revenue Cost Ratios from 2012 Cost Allocation Model Line 70 from O1 in CA	Proposed Revenue to Cost Ratio	Proposed Revenue	Miscellaneous Revenue	Proposed Base Revenue
Residential	2,838,659	2,298,800	214,877	2,513,677	88.6%	88.6%	97.6%	2,771,667	214,877	2,556,790
GS < 50 kW	723,733	690,388	52,162	742,551	102.6%	102.6%	107.4%	777,471	52,162	725,309
GS 50-2999	1,122,655	1,421,087	78,040	1,499,128	133.5%	133.5%	112.2%	1,259,385	78,040	1,181,345
GS 3000 - 4999	136,235	49,144	7,384	56,528	41.5%	41.5%	50.5%	68,799	7,384	61,414
Sentinel Lights	6,222	6,524	528	7,052	113.3%	113.3%	90.0%	5,600	528	5,072
Street Lighting	250,482	249,654	21,666	271,320	108.3%	108.3%	80.0%	200,386	21,666	178,720
USL	53,217	37,145	3,805	40,950	76.9%	76.9%	90.0%	47,896	3,805	44,091
		0	0	0	0.0%	0.0%	0.0%	0	0	0
	0	0	0	0	0.0%	0.00%	0.0%	0	0	0
TOTAL	5,131,204	4,752,741	378,462	5,131,204	100.0%	100.0%		5,131,204	378,462	4,752,742

Table 8-3 below summarizes the movement of revenue at 2012 rates for the base revenue requirement to the proposed base revenue requirement.

Table 8-2 Existing and Proposed Rate Base Revenue

Class	2012 Base Revenues At Existing Rates	2012 Proposed Base Revenue Allocated at Existing Rates Proportion	2012 Proposed Base Revenue Requirement
Residential	1,938,972	2,298,799	2,556,790
GS < 50 kW	582,323	690,388	725,309
GS 50-2999	1,198,646	1,421,087	1,181,345
GS 3000 - 4999	41,451	49,144	61,414
Sentinel Lights	5,503	6,524	5,072
Street Lighting	210,576	249,654	178,720
USL	31,331	37,145	44,091
	4,008,801	**4,752,740**	**4,752,740**

FIXED/VARIABLE PROPORTION

The purpose of this section is to describe the determination of the fixed and variable proportion by rate class, and the calculation of the proposed fixed and variable distribution rates for the 2012 Test year.

Based on applying the existing approved monthly services charges to the forecasted number of customers for 2012 and applying the existing approved distribution volumetric charge excluding the adjustment for transformation allowance, to the 2012 forecasted volumes, the following table outlines the LUI current split between fixed and variable distribution revenue.

Table 8-3 Current Fixed/Variable Split

Customer Class	Total Net Rev. Requirement	Rev Requirement %	Proposed Fixed Rate	Resulting Variable Rate	Total Fixed Revenue	Total Variable Revenue	Transformer Allowance	Gross Distribution Revenue	LV & Wheeling Charges	Total
Residential	2,556,790	53.80%	12.25	$0.0177	$ 1,264,693	$ 1,292,097		2,556,790	97,140	2,653,931
GS < 50 kW	725,309	15.26%	28.02	$0.0101	$ 370,576	$ 354,733		725,309	42,363	767,672
GS 50-2999	1,181,345	24.86%	181.20	$3.3764	$ 276,393	$ 904,951	$ 120,237	1,301,582	145,073	1,446,655
GS 3000 - 4999	61,414	1.29%	2,617.84	$1.2323	$ 31,414	$ 30,000	$ 28,465	89,880	26,735	116,614
Sentinel Lights	5,072	0.11%	4.30	$10.5767	$ 2,768	$ 2,304		5,072	82	5,154
Street Lighting	178,720	3.76%	3.26	$20.6590	$ 109,650	$ 69,070		178,720	1,235	179,955
USL	44,091	0.93%	15.79	$0.0412	$ 14,542	$ 29,549		44,091	1,063	45,154
0	0	0.00%		$0.0000	$ -	$ -		0	0	0
0	0	0.00%		$0.0000	$ -	$ -		0	0	0
TOTAL	4,752,742	100%			$ 2,070,037	$ 2,682,704	$ 148,703	$ 4,901,444	$ 313,691	$ 5,215,135
			Forecast Fixed/Variable Ratios		42.233%	54.733%	3.034%	100.000%		

LUI submits that it is appropriate for 2012 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”. Atikokan Hydro’s MSCs exceed that floor amount by rate class. With respect to the upper bound for the MSC, the OEB considered it to be inappropriate to make changes to the MSC ceiling at this time, given the number of issues that remain to be examined within the scope of the OEB’s Rate Review proceeding (EB-2008-0031). The OEB indicated that for the time being, it does not

expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the MSC; and that distributors that are currently above that value are not required to make changes to their current MSC to bring it to or below that level at this time. In accordance with the filing requirements the following information has been provided with regards to the MSC. The following tables provides the current monthly service charges compared to the floor and ceiling as calculated in the cost allocation study.

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 in the design of the proposed distribution rates. The following table provides the calculation of monthly fixed charge assuming the fixed/variable split is maintained.

Proposed Volumetric Charges:

The volumetric distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate 2012 Test Year usage, kWh or kW, as the class charge determinant.

The following Table provides LUI's calculations of its proposed volumetric distribution charges for the 2012 Test Year which maintains the same fixed/variable split used in designing the current approved rates.

Table 8-4 Current and Proposed Fixed/Variable Proportion

Customer Class	Current Volumetric Split	Current Fixed Charge Spilt	Total	Fixed Rate Based on Current Fixed/Variable Revenue Proportions	2011 Rates From OEB Approved Tariff	Minimum System with PLCC Adustment (Ceiling Fixed Charge From Cost Allocation Model)	Target Fixed Charge Split	Fixed Charge with Target Split
Residential	50.54%	49.46%	100.00%	12.25	9.29	16.32	49.46%	12.25
GS < 50 kW	48.91%	51.09%	100.00%	28.02	22.50	35.11	51.09%	28.02
GS 50-2999	76.60%	23.40%	100.00%	181.20	183.85	76.85	23.40%	181.20
GS 3000 - 4999	48.85%	51.15%	100.00%	2,617.84	1,766.90	618.08	51.15%	2,617.84
Sentinel Lights	45.43%	54.57%	100.00%	4.30	4.66	9.93	54.57%	4.30
Street Lighting	38.65%	61.35%	100.00%	3.26	3.84	9.25	61.35%	3.26
USL	67.02%	32.98%	100.00%	15.79	11.22	42.31	32.98%	15.79
			0.00%	0.00		0.00	0.00%	0.00
TOTAL								

Adjustment to Transformer Allowance:

Currently, LUI provides a Transformer Allowance to those customers that own their transformation facilities. LUI 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. Table 8-5 summarizes the eligible forecasted kW and transformer allowance by rate class. "Eligible forecasted kW" refers to kW demand for those customers who own their transformation facilities within each rate class.

The amount of Transformer Allowance expected to be provided to those General Service > 50 – 2999 kW and General Service > 3000 - 4999 kW customers who own their transformers has been included in the volumetric charge for these classes. As a result, the General Service > 50 – 2,999 kW volumetric charge of $ $ 2.98045 per kW will increase by a rounded figure of $ $ 0.40 , (unrounded $ 0.396) per kW to a total of $$3.3764 per kW to recover the amount of the Transformer Allowance over all kWs in the General Service > 50 – 2,999 kW customer class. The General Service >3,000 – 4,999 kW volumetric charge of $ $ 0.63235 per kW will increase by $

$ 0.600 per kW to a total of $ $1.2323 per kW to recover the amount of the Transformer Allowance over all kWs in the General Service > 3,000 – 4,999 kW customer class.

Table 8-5 Transformer Allowance

Description	2012 Test	
	kW	$
General Service:		
GS 50-2999	200,395	($120,237)
GS 3000 - 4999	47,442	($28,465)
	0	$0
Total	**247,838**	($148,703)
Transformer Allowance rate	($0.60)	

RETAIL TRANSMISSION SERVICE RATES (RTSR):

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.

LUI has completed the Board model and has included the results in the customer class bill impact. LUI understand that the RTSR values may change should the UTR's be revised during the process of the Application. Note the RTS Rates in Table 8-6 below. Attached in Appendix B to this Exhibit is the Board's RTSR model.

Table 8-6 Final 2012 RTS Rates

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0055	$ 0.0044
General Service Less Than 50 kW	kWh	$ 0.0050	$ 0.0040
General Service 50 to 2,999 kW	kW	$ 2.0534	$ 1.5822
General Service 3,000 to 4,999 kW	kW	$ 2.2965	$ 1.8660
Unmetered Scattered Load	kWh	$ 0.0059	$ 0.0049
Sentinel Lighting	kW	$ 1.5563	$ 1.2486
Street Lighting	kW	$ 1.5487	$ 1.2231

LOW VOLTAGE CHARGES

Recovery of Low Voltage (LV) Costs

Consistent with the approach in the Board's 2006 EDR model, LV costs of $ 313,690.80 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 2012 is based on calculations shown in Table 8-7. These calculations are based on applying the appropriate Hydro One Sub Transmission charges to the forecasted units for 2012. The Hydro One Sub Transmission charges used in the calculations are from the Hydro One Approved Rate Schedule.

Table 8-7 Low Voltage Costs

Customer Class	Retail Transmission Connection Rate ($)		Basis for Allocation ($)	Allocation Percentages	Allocated $
	per KWh	per kW			
Residential	0.0044		321,669	30.97%	97,140.40
GS < 50 kW	0.0040		140,280	13.50%	42,362.93
GS 50-2999		1.5822	480,392	46.25%	145,072.83
GS 3000 - 4999		1.8660	88,530	8.52%	26,734.93
Sentinel Lights		1.2486	272	0.03%	82.15
Street Lighting		1.2231	4,089	0.39%	1,234.90
USL	0.0049		3,519	0.34%	1,062.67
0				0.00%	0.00
0			0	0.00%	0.00
TOTALS			1,038,751	100%	313,690.80

The calculation to recover the 2012 LV amount is outlined in the following Table 8-8.

Table 8-8 Low Voltage Adjustment

RATES - Low Voltage Adjustment

Customer Class	LV Adj. Allocated	Calculated kWh	Calculated kW	Volumetric Rate Type	LV/ Adj. Rates/kWh	LV Adj. Rates/ kW
Residential	97,140.40	73,125,152	0	kWh	0.0013	
GS < 50 kW	42,362.93	35,160,634	0	kWh	0.0012	
GS 50-2999	145,072.83	120,608,902	303,629	kW		0.4778
GS 3000 - 4999	26,734.93	19,295,356	47,442	kW		0.5635
Sentinel Lights	82.15	78,431	218	kW		0.3771
Street Lighting	1,234.90	1,215,575	3,343	kW		0.3694
USL	1,062.67	716,623	0	kWh	0.0015	
0	0.00		0	kW		
0	0.00	0	0	kW		0.0000
TOTALS	313,690.80	250,200,673.65	354,632.64			

LOSS ADJUSTMENT FACTORS

Total Loss Factor

LUI is an embedded distributor. LUI has not been required to complete any loss studies as a result of previous decisions.

LUI has calculated the total loss factor to be applied to customer's consumption based on the average wholesale and retail kWh for the five historical years 2005 to 2010. As a result of this analysis, LUI is proposed to set the 2012 Total Loss Factor at 1.0565. This appears to be an increase of 0.0024 from the current approved Total Loss Factor of 1.0541. However as discussed in Exhibit 4, due to an erroneous calculation in the 2008 Cost of Service Application, this is actually an improvement in our Total Loss Factor. Table 8- 9 summarizes the total loss factor calculations.

Supply Facility Loss Factor

The supply facility loss factor (SFLF) calculation represents the loss on supply to LUI and is calculated on the measured quantities between the transformer stations and the wholesale meter points. The SFLF is used to calculate the total loss factor and is an average of 1.0099 as shown in Table 8-10.

Materiality Analysis on Distribution Losses

LUI's Loss Adjustment factor is 5.65% . Pursuant to the OEB Filing Requirements, LUI is not required to provide an explanation of, or justification for its distribution loss factor as it is below the threshold.

Table 8-9 Total Loss Factor

	Lakefront Utilities Inc.								
	Losses in Distributor System		**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**6 Year Average**
A	"Wholesale" kWh (IESO) **Qty at the Meter**		292,286,452	293,670,333	295,056,126	281,805,823	258,040,717	261,165,589	280,337,506.47
B	"Wholesale" kWh (GEN)								-
C	Net "Wholesale" kWh (A)-(B)		292,286,452	293,670,333	295,056,126	281,805,823	258,040,717	261,165,589	280,337,506.47
									-
D	Retail kWh (Distributor) **Qty at the Meter**		277,862,274	283,065,421	281,755,268	271,486,078	245,046,862	248,913,436	268,021,556.72
E	Portion of Retail kWh delivered by distributor for Large Use Customers		-	-	-	-	-	-	-
F	Net "Retail" kWh (D)-(E)		277,862,274	283,065,421	281,755,268	271,486,078	245,046,862	248,913,436	268,021,556.72
G	Distribution Loss Factor [(C)/(F)]		1.0519	1.0375	1.0472	1.0380	1.0530	1.0492	1.0461
	Losses Upstream of Distributor's System								
H	Supply Facility Loss Factor		1.00740	1.00736	1.01003	1.01136	1.01169	1.01173	1.0099
	Three Year Average								1.0116
	Total Utility Loss Adjustment Factor								**LAF**
	Supply Facility Loss Factor								1.0099
I	**Total Loss Factor**								
	Secondary Metered Customer								
	Total Loss Factor - Secondary Metered Customer < 5,000kW								1.0565
	Total Loss Factor - Secondary Metered Customer > 5,000kW								n/a
	Primary Metered Customer								
	Total Loss Factor - Primary Metered Customer < 5,000kW								1.0460
	Total Loss Factor - Primary Metered Customer > 5,000kW								n/a

Table 8-10 Supply Facility Loss Factor

2005	2006	2007	2008	2009	2010	TOTALS
1.0074	1.007357	1.010027	1.011364	1.011686	1.011735	1.009928

Table 8-11 Proposed Loss Factor Summary

Total Utility Loss Adjustment Factor		LAF
Supply Facility Loss Factor		1.0099
Distibution Loss Factor		1.0461
Distribution Loss Factor - Secondary Metered Customer < 5000kW		1.0565
Distribution Loss Factor - Primary Metered Customer < 5000 kW		1.0357
Total Loss Factor		
Total Loss Factor - Secondary Metered Customer < 5000kW		1.0565
Total Loss Factor - Primary Metered Customer < 5000kW		1.0460

LOST REVENUE ADJUSTMENT MECHANISM / SHARED SAVINGS MECHANISM (LRAM/SSM)

LUI is requesting an LRAM amount of $**26,696.67** and no SSM amount. Supporting details for these amounts are included in Exhibit 10, as well as the "The Burman Energy Group Report" attached as Appendix A of Exhibit 10. In the Table below, is the breakdown of LUI's LRAM rate riders.

Table 8-12 LRAM Rate Riders

2012 Test Year - LRAM and SSM Rider

Rate Class	Amounts		Billing Units (2012)		Rate Riders			Two Year Rate Rider	Three Year Rate Rider	Number of Years to Use	Rate Rider to Use
	LRAM	SSM			LRAM	SSM	Total	Total	Total	(2 or 3)	Total
	$	$		Metrics	$/unit (kWh or kW)	$/unit (kWh or kW)	$/unit (kWh or kW)	$/unit (kWh or kW)	$/unit (kWh or kW)		$/unit (kWh or kW)
Residential	17,097.66		73,125,152	kWh	0.0002	0.0000	0.0002	0.0001	0.0001		0.0002
GS < 50 kW	6,796.82		35,160,634	kWh	0.0002	0.0000	0.0002	0.0001	0.0001		0.0002
GS 50-2999	2,093.67		303,629	kW	0.0069	0.0000	0.0069	0.0034	0.0023		0.0069
GS 3000 - 4999	708.53		47,442	kW	0.0149	0.0000	0.0149	0.0075	0.0050		0.0149
Sentinel Lights			218	kW	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000
Street Lighting			3,343	kW	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000
USL			716,623	kWh	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000
0			0	kW	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000
0			0	kW	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000
Total	26,696.67	0.00									

SPECIFIC SERVICE CHARGES

LUI is not seeking any changes or additions to the current Board Approved Specific Service Charges as detailed in the Tariff of Rates and Charges in LUI's 2011 IRM Decision and Order.

SUMMARY OF EXISTING AND PROPOSED SPECIFIC SERVICE CHARGES

Table 8-13 summarizes the existing Specific Service Charges for LUI.

Table 8-13 Specific Service Charges

Item Description	Calculation Basis	Rate ($)
Arrears certificate	Standard	15.00
Statement of account	Standard	15.00
Pulling post dated cheques	Standard	15.00
Request for other billing information	Standard	15.00
Easement letter	Standard	15.00
Income tax letter	Standard	15.00
Credit reference/credit check (plus credit agency costs)	Standard	15.00
Returned cheque charge (plus bank charges)	Standard	15.00
Legal letter charge	Standard	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	Standard	30.00
Special meter reads	Standard	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	Standard	30.00
Collection of account charge - no disconnection	Standard	30.00
Collection of account charge - no disconnection - after regular hours	Standard	165.00
Disconnect/Reconnect at meter - during regular hours	Standard	65.00
Disconnect/Reconnect at meter - after regular hours	Standard	185.00
Disconnect/Reconnect at pole - during regular hours	Standard	185.00
Disconnect/Reconnect at pole - after regular hours	Standard	415.00
Install/Remove load control device - during regular hours	Standard	65.00
Install/Remove load control device - after regular hours	Standard	185.00
Service call - customer-owned equipment	Standard	30.00
Service call - after regular hours	Standard	165.00
Temporary service install & remove - overhead - no transformer	Standard	500.00
Temporary service install & remove - underground - no transformer	Standard	300.00
Temporary service install & remove - overhead - with transformer	Standard	1,000.00
Specific Charge for Access to the Power Poles $/pole/year	Standard	22.35
Interval Meter Load Management Tool Charge $/month	Standard	110.00
Service charge for onsite interrogation of interval meter due to customer phone line failure -required weekly until line repaired	Standard	60.00

EXISTING AND PROPOSED RATE CLASSES

Residential (Existing)

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separated metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex, or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

General Service Less than 50 kW (Existing)

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

General Service 50 to 2,999 kW (Existing)

This classification applies to a non residential account whose average monthly maximum demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 2,000 kW.

General Service Greater than 3,000 kW (Existing)

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than 3,000 kW.

Unmetered Scattered Load (Existing)

This classification refers to an account taking electricity at 750 volts or less whose monthly average maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be

agreed to by the distributor and the customer, based on detailer manufacturer information/documentation with regard to electrical consumption of the unmetered lad or periodic monitoring of actual consumption.

Sentinel Lighting Service (Existing)

This classification refers to accounts that are an unmetered lighting load supplies to a sentinel light.

Street Lighting Service (Existing)

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

microFIT Generator Service (Existing)

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.

EXISTING RATE SCHEDULE

Lakefront Utilities Inc. - May 1 2011

Residential

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	9.29
Smart Meter Funding Adder - effective until April 30, 2012	$	2.50
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.18
Distribution Volumetric Rate	$/kWh	0.0134
Low Voltage Service Rate	$/kWh	0.0013
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kWh	0.0016
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery – effective until April 30, 2012	$/kWh	0.0011
Rate Rider for Tax Change – effective until April 30, 2012	$/kWh	(0.0002)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	22.20
Smart Meter Funding Adder - effective until April 30, 2012	$	2.50
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.44
Distribution Volumetric Rate	$/kWh	0.0081
Low Voltage Service Rate	$/kWh	0.0012
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kWh	0.0016
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery – effective until April 30, 2012	$/kWh	0.0002
Rate Rider for Tax Change – effective until April 30, 2012	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 2,999 kW

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	183.85
Smart Meter Funding Adder - effective until April 30, 2012	$	2.50
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	7.16
Distribution Volumetric Rate	$/kW	3.4201
Low Voltage Service Rate	$/kW	0.4864
Rate Rider for Global Adjustment Sub-Account Disposition (2011) – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kW	0.1398
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kW	0.6360
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery – effective until April 30, 2012	$/kW	0.2507
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.0408)
Retail Transmission Rate – Network Service Rate	$/kW	1.9987
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5466

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 3,000 to 4,999 kW

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	1,766.90
Smart Meter Funding Adder - effective until April 30, 2012	$	2.50
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	47.39
Distribution Volumetric Rate	$/kW	1.0268
Low Voltage Service Rate	$/kW	0.5570
Rate Rider for Global Adjustment Sub-Account Disposition (2011) – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kW	0.1807
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kW	0.6879
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery – effective until April 30, 2012	$/kW	0.6467
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.0122)
Retail Transmission Rate – Network Service Rate	$/kW	2.2353
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.8241

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per customer)	$	11.22
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.28
Distribution Volumetric Rate	$/kWh	0.0293
Low Voltage Service Rate	$/kWh	0.0014
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kWh	0.0015
Rate Rider for Tax Change – effective until April 30, 2012	$/kWh	(0.0004)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	4.66
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.06
Distribution Volumetric Rate	$/kW	11.4737
Low Voltage Service Rate	$/kW	0.3754
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kW	0.7039
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.3968)
Retail Transmission Rate – Network Service Rate	$/kW	1.5148
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2205

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	3.84
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.03
Distribution Volumetric Rate	$/kW	24.3414
Low Voltage Service Rate	$/kW	0.3708
Rate Rider for Global Adjustment Sub-Account Disposition (2011) – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kW	0.1660
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kW	0.6048
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.3250)
Retail Transmission Rate – Network Service Rate	$/kW	1.5074
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1956

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

MicroFIT Generator

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

Allowances

EB-2010-0095

ALLOWANCES

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

Specific Service Charges

Customer Administration		
Arrears certificate	$	15.00
Statement of Account	$	15.00
Pulling post dated cheques	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Collection of account charge - no disconnection – after regular hours	$	165.00
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00
Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Service call - customer-owned equipment	$	30.00
Service call - after regular hours	$	165.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Temporary service install & remove - overhead - with transformer	$	1,000.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Interval Meter Load Management Tool Charge $/month	$	110.00

Retail Service Charges (if applicable)

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

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

LOSS FACTORS

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	1.0541
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0456
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

SCHEDULE OF PROPOSED RATES AND CHARGES

RECONCILIATION OF RATE CLASS REVENUE

2012 Test Year Distribution Revenue Reconciliation

Customer Class	Fixed Distribution Revenue	Variable Distribution Revenue	Transformer Allowance Credit	Total Distribution Revenue	Expected
Residential	$ 1,264,683	$ 1,294,315		$ 2,558,998	$ 2,556,790
GS < 50 kW	$ 370,513	$ 355,122		$ 725,636	$ 725,309
GS 50-2999	$ 276,399	$ 1,025,173	($120,237)	$ 1,181,335	$ 1,181,345
GS 3000 - 4999	$ 31,414	$ 58,463	($28,465)	$ 61,412	$ 61,414
Sentinel Lights	$ 2,768	$ 2,304		$ 5,072	$ 5,072
Street Lighting	$ 109,651	$ 69,070		$ 178,720	$ 178,720
USL	$ 14,542	$ 29,525		$ 44,067	$ 44,091
0	$ -	$ -		$ -	$ -
0	$ -			$ -	$ -
Total	**$ 2,069,971**	**$ 2,833,973**	**($148,703)**	**$ 4,755,241**	**$ 4,752,742**

Difference Due to Rate Rounding
-$ 2,500

RATE AND BILL IMPACTS

Appendix A to this Schedule presents the results of the assessment of customer total bill impacts by customer rate class. Impacts are shown using the applicable current approved rates and the proposed 2012 distribution rates, including rate riders for the disposition of Deferral and Variance Account, for Smart Meters, for Stranded Assets, as discussed in Exhibit 9.

RATE MITIGATION

A significant increase in capital expenditures, adjustments to OM&A costs from 2008 levels to 2012 levels, and reduced consumption resulting from conservation programs have contributed to a revenue deficiency of $ 717,086 for the 2012 cost of service rate application. LUI recognizes that this represents an increase in distribution rates and has taken measures to mitigate these costs to the fairest and most reasonable extent possible in an effort to balance the customer needs with the regulatory and corporate requirements to operate a safe, reliable distribution system.

LUI recognizes that this represents an increase in distribution rates but believes that the proposed rates balance the consumer interest in the price of delivery with the regulatory and corporate requirements to operate a safe, reliable distribution system.

LUI submits that the bill impacts associated with its proposed 2012 electricity rates including rate riders are reasonable and are not significant enough to warrant any mitigation measures.

APPENDIX A TABLE OF RATE AND BILL IMPACTS

RESIDENTIAL

Consumption 100 kWh		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
	Monthly Service Charge			9.29			12.25	2.96	31.86%	41.94%
	Distribution (kWh)	100	0.0134	1.34	100	0.0177	1.77	0.43	32.09%	6.06%
	Low Voltage Rider (kWh)	100	0.0013	0.13	100	0.0013	0.13	0.00	0.00%	0.45%
	Stranded Meters Rate Rider ($/Customer)						2.37	2.37		8.11%
	LRAM & SSM Rider (kWh)	100	0.0011	0.11	100	0.0002	0.02	(0.09)	(78.74%)	0.08%
	Smart Meter Rate Rider ($/Customer)			2.50			0.05	(2.45)	(98.00%)	0.17%
	Late Payment (kWh)	1	0.1800	0.18	1	0.0000	0.00	(0.18)	(100.00%)	0.00%
	Deferrral & Variance Acct (kWh)	100	0.0014	0.14	100	(0.0005)	(0.05)	(0.19)	(134.48%)	(0.17%)
	Distribution Sub-Total			**13.69**			**16.55**	**2.86**	**20.85%**	**56.64%**
	Retail Transmisssion (kWh)	105	0.0097	1.02	106	0.009946716	1.05	0.03	2.78%	3.60%
	Delivery Sub-Total			**14.71**			**17.60**	**2.88**	**19.60%**	**60.24%**
	Other Charges (kWh)	105	0.0131	1.38	106	0.0131	1.39	0.00	0.23%	4.75%
	Cost of Power Commodity (kWh)	105	0.0650	6.85	106	0.0650	6.87	0.02	0.23%	23.51%
	SPC (kWh)	105	0.0000	0.00	105	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**22.95**			**25.85**	**2.90**	**12.65%**	**88.50%**
	GST		13.00%	2.98		13.00%	3.36	0.38	12.65%	11.50%
	Total Bill			**25.93**			**29.21**	**3.28**	**12.65%**	**100.00%**

RESIDENTIAL

Consumption 250 kWh		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
	Monthly Service Charge			9.29			12.25	2.96	31.86%	25.44%
	Distribution (kWh)	250	0.0134	3.35	250	0.0177	4.43	1.08	32.09%	9.19%
	Low Voltage Rider (kWh)	250	0.0013	0.33	250	0.0013	0.33	0.00	0.00%	0.67%
	Stranded Meters Rate Rider ($/Customer)			0.00			2.37	2.37		4.92%
	LRAM & SSM Rider (kWh)	250	0.0011	0.28	250	0.0002	0.06	(0.22)	(78.74%)	0.12%
	Smart Meter Rate Rider ($/Customer)			2.50			0.05	(2.45)	(98.00%)	0.10%
	Late Payment (kWh)	1	0.1800	0.18	1	0.0000	0.00	(0.18)	(100.00%)	0.00%
	Deferrral & Variance Acct (kWh)	250	0.0014	0.35	250	(0.0005)	(0.12)	(0.47)	(134.48%)	(0.25%)
	Distribution Sub-Total			**16.27**			**19.36**	**3.09**	**18.98%**	**40.19%**
	Retail Transmisssion (kWh)	264	0.0097	2.56	264	0.009946716	2.63	0.07	2.78%	5.46%
	Delivery Sub-Total			**18.83**			**21.98**	**3.16**	**16.78%**	**45.65%**
	Other Charges (kWh)	264	0.0131	3.46	264	0.0131	3.47	0.01	0.23%	7.20%
	Cost of Power Commodity (kWh)	264	0.0650	17.13	264	0.0650	17.17	0.04	0.23%	35.65%
	SPC (kWh)	264	0.0000	0.00	264	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**39.41**			**42.62**	**3.21**	**8.13%**	**88.50%**
	GST		13.00%	5.12		13.00%	5.54	0.42	8.13%	11.50%
	Total Bill			**44.54**			**48.16**	**3.62**	**8.13%**	**100.00%**

RESIDENTIAL

Consumption 500 kWh	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			9.29			12.25	2.96	31.86%	15.36%
Distribution (kWh)	500	0.0134	6.70	500	0.0177	8.85	2.15	32.09%	11.10%
Low Voltage Rider (kWh)	500	0.0013	0.65	500	0.0013	0.65	0.00	0.00%	0.82%
Stranded Meters Rate Rider ($/Customer)			0.00			2.37	2.37		2.97%
LRAM & SSM Rider (kWh)	500	0.0011	0.55	500	0.0002	0.12	(0.43)	(78.74%)	0.15%
Smart Meter Rate Rider ($/Customer)			2.50			0.05	(2.45)	(98.00%)	0.06%
Late Payment (kWh)	1	0.1800	0.18	1	0.0000	0.00	(0.18)	(100.00%)	0.00%
Deferrral & Variance Acct (kWh)	500	0.0014	0.70	500	(0.0005)	(0.24)	(0.94)	(134.48%)	(0.30%)
Distribution Sub-Total			**20.57**			**24.05**	**3.48**	**16.90%**	**30.15%**
Retail Transmisssion (kWh)	527	0.0097	5.11	528	0.009946716	5.25	0.14	2.78%	6.59%
Delivery Sub-Total			**25.68**			**29.30**	**3.62**	**14.09%**	**36.74%**
Other Charges (kWh)	527	0.0131	6.92	528	0.0131	6.93	0.02	0.23%	8.69%
Cost of Power Commodity (kWh)	527	0.0650	34.26	528	0.0650	34.34	0.08	0.23%	43.06%
SPC (kWh)	527	0.0000	0.00	527	0.0000	0.00	0.00		0.00%
Total Bill Before Taxes			**66.86**			**70.57**	**3.71**	**5.55%**	**88.50%**
GST		13.00%	8.69		13.00%	9.17	0.48	5.55%	11.50%
Total Bill			**75.55**			**79.74**	**4.19**	**5.55%**	**100.00%**

RESIDENTIAL

Consumption 680 kWh	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			9.29			12.25	2.96	31.86%	11.80%
Distribution (kWh)	680	0.0134	9.11	680	0.0177	12.04	2.92	32.09%	11.59%
Low Voltage Rider (kWh)	680	0.0013	0.88	680	0.0013	0.88	0.00	0.00%	0.85%
Stranded Meters Rate Rider ($/Customer)			0.00			2.37	2.37		2.28%
LRAM & SSM Rider (kWh)	680	0.0011	0.75	680	0.0002	0.16	(0.59)	(78.74%)	0.15%
Smart Meter Rate Rider ($/Customer)			2.50			0.05	(2.45)	(98.00%)	0.05%
Late Payment (kWh)	1	0.1800	0.18	1	0.0000	0.00	(0.18)	(100.00%)	0.00%
Deferrral & Variance Acct (kWh)	680	0.0014	0.95	680	(0.0005)	(0.33)	(1.28)	(134.48%)	(0.32%)
Distribution Sub-Total			**23.67**			**27.42**	**3.75**	**15.87%**	**26.41%**
Retail Transmisssion (kWh)	717	0.0097	6.95	718	0.009946716	7.15	0.19	2.78%	6.88%
Delivery Sub-Total			**30.62**			**34.57**	**3.95**	**12.89%**	**33.29%**
Other Charges (kWh)	717	0.0131	9.41	718	0.0131	9.43	0.02	0.23%	9.08%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	37.56%
Cost of Power Commodity (kWh)	117	0.0750	8.76	118	0.0750	8.88	0.12	1.41%	8.56%
SPC (kWh)	717	0.0000	0.00	717	0.0000	0.00	0.00		0.00%
Total Bill Before Taxes			**87.79**			**91.88**	**4.09**	**4.66%**	**88.50%**
GST		13.00%	11.41		13.00%	11.94	0.53	4.66%	11.50%
Total Bill			**99.20**			**103.82**	**4.63**	**4.66%**	**100.00%**

RESIDENTIAL

Consumption 800 kWh	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			9.29			12.25	2.96	31.86%	10.17%
Distribution (kWh)	800	0.0134	10.72	800	0.0177	14.16	3.44	32.09%	11.76%
Low Voltage Rider (kWh)	800	0.0013	1.04	800	0.0013	1.04	0.00	0.00%	0.86%
Stranded Meters Rate Rider ($/Customer)			0.00			2.37	2.37		1.97%
LRAM & SSM Rider (kWh)	800	0.0011	0.88	800	0.0002	0.19	(0.69)	(78.74%)	0.16%
Smart Meter Rate Rider ($/Customer)			2.50			0.05	(2.45)	(98.00%)	0.04%
Late Payment (kWh)	1	0.1800	0.18	1	0.0000	0.00	(0.18)	(100.00%)	0.00%
Deferrral & Variance Acct (kWh)	800	0.0014	1.12	800	(0.0005)	(0.39)	(1.51)	(134.48%)	(0.32%)
Distribution Sub-Total			**25.73**			**29.67**	**3.94**	**15.32%**	**24.64%**
Retail Transmisssion (kWh)	843	0.0097	8.18	845.22	0.009946716	8.41	0.23	2.78%	6.98%
Delivery Sub-Total			**33.91**			**38.08**	**4.17**	**12.29%**	**31.62%**
Other Charges (kWh)	843	0.0131	11.07	845.22	0.0131	11.09	0.03	0.23%	9.21%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600.00	0.0650	39.00	0.00	0.00%	32.39%
Cost of Power Commodity (kWh)	243.28	0.075000	18.246000	245.22	0.0750	18.39	0.15	0.80%	15.27%
SPC (kWh)	843	0.0000	0.00	843.28	0.0000	0.00	0.00		0.00%
Total Bill Before Taxes			**102.22**			**106.56**	**4.35**	**4.25%**	**88.50%**
GST		13.00%	13.29		13.00%	13.85	0.56	4.24%	11.50%
Total Bill			**115.51**			**120.42**	**4.92**	**4.26%**	**100.00%**

RESIDENTIAL

Consumption 1,000 kWh		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
	Monthly Service Charge			9.29			12.25	2.96	31.86%	4.04%
	Distribution (kWh)	1,000	0.0134	13.40	1,000	0.0177	17.70	4.30	32.09%	5.84%
	Low Voltage Rider (kWh)	1,000	0.0013	1.30	1,000	0.0013	1.30	0.00	0.00%	0.43%
	Stranded Meters Rate Rider ($/Customer)			0.00			2.37	2.37		0.78%
	LRAM & SSM Rider (kWh)	1,000	0.0011	1.10	1,000	0.0002	0.23	(0.87)	(78.74%)	0.08%
	Smart Meter Rate Rider ($/Customer)			2.50			0.05	(2.45)	(98.00%)	0.02%
	Late Payment (kWh)	1	0.1800	0.18	1	0.0000	0.00	(0.18)	(100.00%)	0.00%
	Deferrral & Variance Acct (kWh)	1,000	0.0014	1.40	1,000	(0.0005)	(0.48)	(1.88)	(134.48%)	(0.16%)
	Distribution Sub-Total			**29.17**			**33.42**	**4.25**	**14.57%**	**11.03%**
	Retail Transmisssion (kWh)	1,054	0.0097	10.22	1,057	0.009946716	10.51	0.28	2.78%	3.47%
	Delivery Sub-Total			**39.39**			**43.93**	**4.54**	**11.51%**	**14.50%**
	Other Charges (kWh)	1,054	0.0131	13.84	1,057	0.0131	13.87	0.03	0.23%	4.58%
	Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	12.87%
	Cost of Power Commodity (kWh)	454	0.0750	34.06	457	0.0750	34.24	0.18	0.53%	11.30%
	SPC (kWh)	1,054	0.1300	137.03	1,054	0.1300	137.03	0.00	0.00%	45.24%
	Total Bill Before Taxes			**263.32**			**268.07**	**4.75**	**1.80%**	**88.50%**
	GST		13.00%	34.23		13.00%	34.85	0.62	1.80%	11.50%
	Total Bill			**297.55**			**302.92**	**5.37**	**1.80%**	**100.00%**

RESIDENTIAL

Consumption 1,500 kWh		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
	Monthly Service Charge			9.29			12.25	2.96	31.86%	2.73%
	Distribution (kWh)	1,500	0.0134	20.10	1,500	0.0177	26.55	6.45	32.09%	5.91%
	Low Voltage Rider (kWh)	1,500	0.0013	1.95	1,500	0.0013	1.95	0.00	0.00%	0.43%
	Stranded Meters Rate Rider ($/Customer)			0.00			2.37	2.37		0.53%
	LRAM & SSM Rider (kWh)	1,500	0.0011	1.65	1,500	0.0002	0.35	(1.30)	(78.74%)	0.08%
	Smart Meter Rate Rider ($/Customer)			2.50			0.05	(2.45)	(98.00%)	0.01%
	Late Payment (kWh)	1	0.1800	0.18	1	0.0000	0.00	(0.18)	(100.00%)	0.00%
	Deferrral & Variance Acct (kWh)	1,500	0.0014	2.10	1,500	(0.0005)	(0.72)	(2.82)	(134.48%)	(0.16%)
	Distribution Sub-Total			**37.77**			**42.80**	**5.03**	**13.31%**	**9.52%**
	Retail Transmisssion (kWh)	1,581	0.0097	15.34	1,585	0.009946716	15.76	0.43	2.78%	3.51%
	Delivery Sub-Total			**53.11**			**58.56**	**5.45**	**10.27%**	**13.03%**
	Other Charges (kWh)	1,581	0.0131	20.75	1,585	0.0131	20.80	0.05	0.23%	4.63%
	Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	8.68%
	Cost of Power Commodity (kWh)	981	0.0750	73.59	985	0.0750	73.86	0.27	0.37%	16.43%
	SPC (kWh)	1,581	0.1300	205.55	1,581	0.1300	205.55	0.00	0.00%	45.73%
	Total Bill Before Taxes			**392.00**			**397.77**	**5.77**	**1.47%**	**88.50%**
	GST		13.00%	50.96		13.00%	51.71	0.75	1.47%	11.50%
	Total Bill			**442.96**			**449.48**	**6.52**	**1.47%**	**100.00%**

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GENERAL SERVICE < 50 kW

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			22.50			28.02	5.52	24.53%	9.86%
2,000 kWh	Distribution (kWh)	2,000	0.0081	16.20	2,000	0.0101	20.20	4.00	24.69%	7.11%
	Low Voltage Rider (kWh)	2,000	0.0012	2.40	2,000	0.0012	2.40	0.00	0.00%	0.84%
	Stranded Meters Rate Rider ($/Customer)			2.50			2.37	(0.13)	(5.20%)	0.83%
	LRAM & SSM Rider (kWh)	2,000	0.0002	0.40	2,000	0.0002	0.39	(0.01)	(3.35%)	0.14%
	Smart Meter Rate Rider ($/Customer)			2.50			0.05	(2.45)	(98.00%)	0.02%
	Late Payment (kWh)	1	0.4400	0.44	1	0.0000	0.00	(0.44)	(100.00%)	0.00%
	Deferrral & Variance Acct (kWh)	2,000	0.0015	3.00	2,000	(0.0006)	(1.27)	(4.27)	(142.38%)	(0.45%)
	Distribution Sub-Total			**49.94**			**52.16**	**2.22**	**4.44%**	**18.36%**
	Retail Transmisssion (kWh)	2,108	0.0088	18.55	2,113.05	0.00902383	19.07	0.52	2.78%	6.71%
	Delivery Sub-Total			**68.49**			**71.22**	**2.73**	**3.99%**	**25.07%**
	Other Charges (kWh)	2,108.20	0.013125	27.67	2,113	0.0131	27.73	0.06	0.23%	9.76%
	Cost of Power Commodity (kWh)	600.00	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	13.73%
	Cost of Power Commodity (kWh)	1,508.20	0.0750	113.12	1,513	0.0750	113.48	0.36	0.32%	39.94%
	SPC (kWh)	2,108.20	0.0000	0.00	2,108	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**248.28**			**251.43**	**$3.16**	**1.27%**	**88.49%**
	GST		13.00%	32.28		13.00%	32.69	0.41	1.27%	11.50%
	Total Bill			**280.55**			**284.12**	**$3.57**	**1.27%**	**100.00%**

GENERAL SERVICE < 50 kW

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			22.50			28.02	5.52	24.53%	4.19%
5,000 kWh	Distribution (kWh)	5,000	0.0081	40.50	5,000	0.0101	50.50	10.00	24.69%	7.55%
	Low Voltage Rider (kWh)	5,000	0.0012	6.00	5,000	0.0012	6.00	0.00	0.00%	0.90%
	Stranded Meters Rate Rider ($/Customer)			2.50			2.37	(0.13)	(5.20%)	0.35%
	LRAM & SSM Rider (kWh)	5,000	0.0002	1.00	5,000	0.0002	0.97	(0.03)	(3.35%)	0.14%
	Smart Meter Rate Rider ($/Customer)			2.50			0.05	(2.45)	(98.00%)	0.01%
	Late Payment (kWh)	1	0.4400	0.44	1	0.0000	0.00	(0.44)	(100.00%)	0.00%
	Deferrral & Variance Acct (kWh)	5,000	0.0015	7.50	5,000	(0.0006)	(3.18)	(10.68)	(142.38%)	(0.48%)
	Distribution Sub-Total			**82.94**			**84.73**	**1.79**	**2.16%**	**12.67%**
	Retail Transmisssion (kWh)	5,271	0.0088	46.38	5,283	0.00902383	47.67	1.29	2.78%	7.13%
	Delivery Sub-Total			**129.32**			**132.40**	**3.08**	**2.38%**	**19.79%**
	Other Charges (kWh)	5,271	0.0131	69.18	5,283	0.0131	69.34	0.16	0.23%	10.37%
	Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	5.83%
	Cost of Power Commodity (kWh)	4,671	0.0750	350.29	4,683	0.0750	351.20	0.91	0.26%	52.51%
	SPC (kWh)	5,271	0.0000	0.00	5,271	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**587.79**			**591.93**	**$4.15**	**0.71%**	**88.50%**
	GST		13.00%	76.41		13.00%	76.95	0.54	0.71%	11.50%
	Total Bill			**664.20**			**668.88**	**$4.69**	**0.71%**	**100.00%**

GENERAL SERVICE < 50 kW

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			22.50			28.02	5.52	24.53%	2.14%
10,000 kWh	Distribution (kWh)	10,000	0.0081	81.00	10,000	0.0101	101.00	20.00	24.69%	7.71%
	Low Voltage Rider (kWh)	10,000	0.0012	12.00	10,000	0.0012	12.00	0.00	0.00%	0.92%
	Stranded Meters Rate Rider ($/Customer)			2.50			2.37	(0.13)	(5.20%)	0.18%
	LRAM & SSM Rider (kWh)	10,000	0.0002	2.00	10,000	0.0002	1.93	(0.07)	(3.35%)	0.15%
	Smart Meter Rate Rider ($/Customer)			2.50			0.05	(2.45)	(98.00%)	0.00%
	Late Payment (kWh)	1	0.4400	0.44	1	0.0000	0.00	(0.44)	(100.00%)	0.00%
	Deferrral & Variance Acct (kWh)	10,000	0.0015	15.00	10,000	(0.0006)	(6.36)	(21.36)	(142.38%)	(0.49%)
	Distribution Sub-Total			**137.94**			**139.02**	**1.08**	**0.78%**	**10.61%**
	Retail Transmisssion (kWh)	10,541	0.0088	92.76	10,565	0.00902383	95.34	2.58	2.78%	7.28%
	Delivery Sub-Total			**230.70**			**234.36**	**3.65**	**1.58%**	**17.89%**
	Other Charges (kWh)	10,541	0.0131	138.36	10,565	0.0131	138.67	0.32	0.23%	10.58%
	Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	2.98%
	Cost of Power Commodity (kWh)	9,941	0.0750	745.58	9,965	0.0750	747.40	1.82	0.24%	57.05%
	SPC (kWh)	10,541	0.0000	0.00	10,541	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**1,153.63**			**1,159.42**	**$5.79**	**0.50%**	**88.50%**
	GST		13.00%	149.97		13.00%	150.73	0.75	0.50%	11.50%
	Total Bill			**1,303.60**			**1,310.15**	**$6.55**	**0.50%**	**100.00%**

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GENERAL SERVICE < 50 kW

Consumption 12,500 kWh		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
	Monthly Service Charge			22.50			28.02	5.52	24.53%	1.72%
	Distribution (kWh)	12,500	0.0081	101.25	12,500	0.0101	126.25	25.00	24.69%	7.74%
	Low Voltage Rider (kWh)	12,500	0.0012	15.00	12,500	0.0012	15.00	0.00	0.00%	0.92%
	Stranded Meters Rate Rider ($/Customer)			2.50			2.37	(0.13)	(5.20%)	0.15%
	LRAM & SSM Rider (kWh)	12,500	0.0002	2.50	12,500	0.0002	2.42	(0.08)	(3.35%)	0.15%
	Smart Meter Rate Rider ($/Customer)			2.50			0.05	(2.45)	(98.00%)	0.00%
	Late Payment (kWh)	1	0.4400	0.44	1	0.0000	0.00	(0.44)	(100.00%)	0.00%
	Deferrral & Variance Acct (kWh)	12,500	0.0015	18.75	12,500	(0.0006)	(7.95)	(26.70)	(142.38%)	(0.49%)
	Distribution Sub-Total			**165.44**			**166.16**	**0.72**	**0.44%**	**10.19%**
	Retail Transmisssion (kWh)	13,176	0.0088	115.95	13,207	0.00902383	119.17	3.22	2.78%	7.31%
	Delivery Sub-Total			**281.39**			**285.33**	**3.94**	**1.40%**	**17.50%**
	Other Charges (kWh)	13,176	0.0131	172.94	13,207	0.0131	173.34	0.40	0.23%	10.63%
	Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	2.39%
	Cost of Power Commodity (kWh)	12,576	0.0750	943.22	12,607	0.0750	945.49	2.28	0.24%	57.98%
	SPC (kWh)	13,176	0.0000	0.00	13,176	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**1,436.55**			**1,443.17**	**$6.62**	**0.46%**	**88.50%**
	GST		13.00%	186.75		13.00%	187.61	0.86	0.46%	11.50%
	Total Bill			**1,623.31**			**1,630.78**	**$7.48**	**0.46%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption 15,000 kWh		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
	Monthly Service Charge			22.50			28.02	5.52	24.53%	1.44%
	Distribution (kWh)	15,000	0.0081	121.50	15,000	0.0101	151.50	30.00	24.69%	7.76%
	Low Voltage Rider (kWh)	15,000	0.0012	18.00	15,000	0.0012	18.00	0.00	0.00%	0.92%
	Stranded Meters Rate Rider ($/Customer)			2.50			2.37	(0.13)	(5.20%)	0.12%
	LRAM & SSM Rider (kWh)	15,000	0.0002	3.00	15,000	0.0002	2.90	(0.10)	(3.35%)	0.15%
	Smart Meter Rate Rider ($/Customer)			2.50			0.05	(2.45)	(98.00%)	0.00%
	Late Payment (kWh)	1	0.4400	0.44	1	0.0000	0.00	(0.44)	(100.00%)	0.00%
	Deferrral & Variance Acct (kWh)	15,000	0.0015	22.50	15,000	(0.0006)	(9.54)	(32.04)	(142.38%)	(0.49%)
	Distribution Sub-Total			**192.94**			**193.30**	**0.36**	**0.19%**	**9.91%**
	Retail Transmisssion (kWh)	15,812	0.0088	139.14	15,848	0.00902383	143.01	3.87	2.78%	7.33%
	Delivery Sub-Total			**332.08**			**336.31**	**4.23**	**1.27%**	**17.23%**
	Other Charges (kWh)	15,812	0.0131	207.53	15,848	0.0131	208.01	0.48	0.23%	10.66%
	Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	2.00%
	Cost of Power Commodity (kWh)	15,212	0.0750	1,140.86	15,248	0.0750	1,143.59	2.73	0.24%	58.60%
	SPC (kWh)	15,812	0.0000	0.00	15,812	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**1,719.48**			**1,726.92**	**$7.44**	**0.43%**	**88.50%**
	GST		13.00%	223.53		13.00%	224.50	0.97	0.43%	11.50%
	Total Bill			**1,943.01**			**1,951.42**	**$8.41**	**0.43%**	**100.00%**

GENERAL SERVICE > 50 - 2999 kW

Consumption		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
30,000 kWh	Monthly Service Charge			183.85			181.20	(2.65)	(1.44%)	4.74%
100 kW	Distribution (kW)	100	3.4201	342.01	100	3.3764	337.64	(4.37)	(1.28%)	8.83%
	Low Voltage Rider (kW)	100	0.4864	48.64	100	0.4778	47.78	(0.86)	(1.77%)	1.25%
	Stranded Meters Rate Rider ($/Customer)			2.50			2.50	0.00	0.00%	0.07%
	LRAM & SSM Rider (kW)	100		0.00	100	0.0069	0.69	0.69		0.02%
	Smart Meter Rate Rider ($/Customer)			0.00			0.05	0.05		0.00%
	Late Payment (kWh)	1	7.1600	7.16	1	0.0000	0.00	(7.16)	(100.00%)	0.00%
	Deferrral & Variance Acct (kW)	100	0.5952	59.52	100	(0.2750)	(27.50)	(87.02)	(146.20%)	(0.72%)
	Distribution Sub-Total			**643.68**			**542.36**	**(101.32)**	**(15.74%)**	**14.19%**
	Retail Transmisssion (kW)	100	3.5453	354.53	100	3.635583156	363.56	9.03	2.55%	9.51%
	Delivery Sub-Total			**998.21**			**905.92**	**(92.29)**	**(9.25%)**	**23.70%**
	Other Charges (kWh)	31,623	0.0131	415.07	31,696	0.0131	416.02	0.96	0.23%	10.89%
	Cost of Power Commodity (kWh)	31,623	0.0650	2,055.50	31,696	0.0650	2,060.23	4.73	0.23%	53.91%
	SPC (kWh)	31,623	0.0000	0.00	31,623	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**3,468.77**			**3,382.17**	**(86.60)**	**(2.50%)**	**88.50%**
	GST		13.00%	450.94		13.00%	439.68	(11.26)	(2.50%)	11.50%
	Total Bill			**3,919.71**			**3,821.85**	**(97.86)**	**(2.50%)**	**100.00%**

GENERAL SERVICE > 50 - 2999 kW

Consumption		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
75,000 kWh	Monthly Service Charge			183.85			181.20	(2.65)	(1.44%)	1.96%
250 kW	Distribution (kW)	250	3.4201	855.03	250	3.3764	844.10	(10.93)	(1.28%)	9.13%
	Low Voltage Rider (kW)	250	0.4864	121.60	250	0.4778	119.45	(2.15)	(1.77%)	1.29%
	Stranded Meters Rate Rider ($/Customer)			2.50			2.50	0.00	0.00%	0.03%
	LRAM & SSM Rider (kW)	250		0.00	250	0.0069	1.72	1.72		0.02%
	Smart Meter Rate Rider ($/Customer)			0.00			0.05	0.05		0.00%
	Late Payment (kWh)	1	7.1600	7.16	1	0.0000	0.00	(7.16)	(100.00%)	0.00%
	Deferrral & Variance Acct (kW)	250	0.5952	148.80	250	(0.2750)	(68.74)	(217.54)	(146.20%)	(0.74%)
	Distribution Sub-Total			**1,318.94**			**1,080.28**	**(238.65)**	**(18.09%)**	**11.69%**
	Retail Transmisssion (kW)	250	3.5453	886.33	250	3.635583156	908.90	22.57	2.55%	9.83%
	Delivery Sub-Total			**2,205.26**			**1,989.18**	**(216.08)**	**(9.80%)**	**21.52%**
	Other Charges (kWh)	79,058	0.0131	1,037.67	79,240	0.0131	1,040.06	2.39	0.23%	11.25%
	Cost of Power Commodity (kWh)	79,058	0.0650	5,138.74	79,240	0.0650	5,150.57	11.83	0.23%	55.72%
	SPC (kWh)	79,058	0.0000	0.00	79,058	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**8,381.67**			**8,179.80**	**(201.86)**	**(2.41%)**	**88.50%**
	GST		13.00%	1,089.62		13.00%	1,063.37	(26.24)	(2.41%)	11.50%
	Total Bill			**9,471.28**			**9,243.18**	**(228.10)**	**(2.41%)**	**100.00%**

GENERAL SERVICE > 50 - 2999 kW

Consumption		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
100,000 kWh	Monthly Service Charge			183.85			181.20	(2.65)	(1.44%)	1.46%
350 kW	Distribution (kW)	350	3.4201	1,197.04	350	3.3764	1,181.74	(15.30)	(1.28%)	9.54%
	Low Voltage Rider (kW)	350	0.4864	170.24	350	0.4778	167.23	(3.01)	(1.77%)	1.35%
	Stranded Meters Rate Rider ($/Customer)			2.50			2.50	0.00	0.00%	0.02%
	LRAM & SSM Rider (kW)	350		0.00	350	0.0069	2.41	2.41		0.02%
	Smart Meter Rate Rider ($/Customer)			0.00			0.05	0.05		0.00%
	Late Payment (kWh)	1	7.1600	7.16	1	0.0000	0.00	(7.16)	(100.00%)	0.00%
	Deferrral & Variance Acct (kW)	350	0.5952	208.32	350	(0.2750)	(96.24)	(304.56)	(146.20%)	(0.78%)
	Distribution Sub-Total			**1,769.11**			**1,438.90**	**(330.21)**	**(18.67%)**	**11.61%**
	Retail Transmisssion (kW)	350	3.5453	1,240.86	350	3.635583156	1,272.45	31.60	2.55%	10.27%
	Delivery Sub-Total			**3,009.96**			**2,711.35**	**(298.61)**	**(9.92%)**	**21.88%**
	Other Charges (kWh)	105,410	0.0131	1,383.56	105,653	0.0131	1,386.74	3.19	0.23%	11.19%
	Cost of Power Commodity (kWh)	105,410	0.0650	6,851.65	105,653	0.0650	6,867.42	15.77	0.23%	55.42%
	SPC (kWh)	105,410	0.0000	0.00	105,410	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**11,245.17**			**10,965.52**	**(279.65)**	**(2.49%)**	**88.50%**
	GST		13.00%	1,461.87		13.00%	1,425.52	(36.35)	(2.49%)	11.50%
	Total Bill			**12,707.04**			**12,391.03**	**(316.00)**	**(2.49%)**	**100.00%**

GENERAL SERVICE > 50 - 2999 kW

Consumption		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
800,000 kWh	Monthly Service Charge			183.85			181.20	(2.65)	(1.44%)	0.20%
2,000 kW	Distribution (kW)	2,000	3.4201	6,840.20	2,000	3.3764	6,752.80	(87.40)	(1.28%)	7.41%
	Low Voltage Rider (kW)	2,000	0.4864	972.80	2,000	0.4778	955.60	(17.20)	(1.77%)	1.05%
	Stranded Meters Rate Rider ($/Customer)			2.50			2.50	0.00	0.00%	0.00%
	LRAM & SSM Rider (kW)	2,000		0.00	2,000	0.0069	13.79	13.79		0.02%
	Smart Meter Rate Rider ($/Customer)			0.00			0.05	0.05		0.00%
	Late Payment (kWh)	1	7.1600	7.16	1	0.0000	0.00	(7.16)	(100.00%)	0.00%
	Deferrral & Variance Acct (kW)	2,000	0.5952	1,190.40	2,000	(0.2750)	(549.92)	(1,740.32)	(146.20%)	(0.60%)
	Distribution Sub-Total			**9,196.91**			**7,356.02**	**(1,840.89)**	**(20.02%)**	**8.07%**
	Retail Transmisssion (kW)	2,000	3.5453	7,090.60	2,000	3.635583156	7,271.17	180.57	2.55%	7.98%
	Delivery Sub-Total			**16,287.51**			**14,627.19**	**(1,660.32)**	**(10.19%)**	**16.05%**
	Other Charges (kWh)	843,280	0.0131	11,068.46	845,221	0.0131	11,093.94	25.48	0.23%	12.17%
	Cost of Power Commodity (kWh)	843,280	0.0650	54,813.20	845,221	0.0650	54,939.39	126.19	0.23%	60.28%
	SPC (kWh)	843,280	0.0000	0.00	843,280	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**82,169.17**			**80,660.52**	**(1,508.65)**	**(1.84%)**	**88.50%**
	GST		13.00%	10,681.99		13.00%	10,485.87	(196.12)	(1.84%)	11.50%
	Total Bill			**92,851.16**			**91,146.38**	**(1,704.78)**	**(1.84%)**	**100.00%**

GENERAL SERVICE > 50 - 2999 kW

Consumption		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
1,600,000 kWh	Monthly Service Charge			183.85			181.20	(2.65)	(1.44%)	0.10%
4,000 kW	Distribution (kW)	4,000	3.4201	13,680.40	4,000	3.3764	13,505.60	(174.80)	(1.28%)	7.42%
	Low Voltage Rider (kW)	4,000	0.4864	1,945.60	4,000	0.4778	1,911.20	(34.40)	(1.77%)	1.05%
	Stranded Meters Rate Rider ($/Customer)			2.50			2.50	0.00	0.00%	0.00%
	LRAM & SSM Rider (kW)	4,000		0.00	4,000	0.0069	27.58	27.58		0.02%
	Smart Meter Rate Rider ($/Customer)			0.00			0.05	0.05		0.00%
	Late Payment (kWh)	1	7.1600	7.16	1	0.0000	0.00	(7.16)	(100.00%)	0.00%
	Deferrral & Variance Acct (kW)	4,000	0.5952	2,380.80	4,000	(0.2750)	(1,099.84)	(3,480.64)	(146.20%)	(0.60%)
	Distribution Sub-Total			**18,200.31**			**14,528.29**	**(3,672.02)**	**(20.18%)**	**7.98%**
	Retail Transmisssion (kW)	4,000	3.5453	14,181.20	4,000	3.635583156	14,542.33	361.13	2.55%	7.99%
	Delivery Sub-Total			**32,381.51**			**29,070.62**	**(3,310.89)**	**(10.22%)**	**15.97%**
	Other Charges (kWh)	1,686,560	0.0131	22,136.91	1,690,443	0.0131	22,187.88	50.96	0.23%	12.19%
	Cost of Power Commodity (kWh)	1,686,560	0.0650	109,626.40	1,690,443	0.0650	109,878.78	252.38	0.23%	60.34%
	SPC (kWh)	1,686,560	0.0000	0.00	1,686,560	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**164,144.82**			**161,137.28**	**(3,007.54)**	**(1.83%)**	**88.50%**
	GST		13.00%	21,338.83		13.00%	20,947.85	(390.98)	(1.83%)	11.50%
	Total Bill			**185,483.65**			**182,085.13**	**(3,398.52)**	**(1.83%)**	**100.00%**

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Consumption		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
1,607,946 kWh	Monthly Service Charge			1,766.90			2,617.84	850.94	48.16%	1.47%
3,954 kW	Distribution (kW)	3,954	1.0268	4,059.48	3,954	1.2323	4,871.93	812.45	20.01%	2.73%
	Low Voltage Rider (kW)	3,954	0.557	2,202.11	3,954	0.5635	2,227.81	25.70	1.17%	1.25%
	Stranded Meters Rate Rider ($/Customer)			2.50			2.37	(0.13)	(5.20%)	0.00%
	LRAM & SSM Rider (kW)	3,954		0.00	3,954	0.0149	59.04	59.04		0.03%
	Smart Meter Rate Rider ($/Customer)			0.00			0.05	0.05		0.00%
	Late Payment (kWh)	1	47.3900	47.39	1	0.0000	0.00	(47.39)	(100.00%)	0.00%
	Deferrral & Variance Acct (kW)	3,954	0.6757	2,671.40	3,954	(0.2836)	(1,121.04)	(3,792.44)	(141.96%)	(0.63%)
	Distribution Sub-Total			**10,749.78**			**8,658.01**	**(2,091.78)**	**(19.46%)**	**4.85%**
	Retail Transmisssion (kW)	3,954	4.0594	16,048.94	3,954	4.16254195	16,456.72	407.77	2.54%	9.23%
	Delivery Sub-Total			**26,798.72**			**25,114.72**	**(1,684.00)**	(6.28%)	**14.08%**
	Other Charges (kWh)	1,694,936	0.0131	22,246.86	1,698,838	0.0131	22,298.07	51.22	0.23%	12.50%
	Cost of Power Commodity (kWh)	1,694,936	0.0650	110,170.85	1,698,838	0.0650	110,424.49	253.64	**0.23%**	61.91%
	SPC (kWh)	1,694,936	0.0000	0.00	1,694,936	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**159,216.43**			**157,837.29**	**(1,379.15)**	**(0.87%)**	**88.50%**
	GST		13.00%	20,698.14		13.00%	20,518.85	(179.29)	(0.87%)	11.50%
	Total Bill			**179,914.57**			**178,356.13**	**(1,558.44)**	**(0.87%)**	**100.00%**

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Consumption		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
3,100,000 kWh	Monthly Service Charge			1,766.90			2,617.84	850.94	48.16%	0.77%
7,500 kW	Distribution (kW)	7,500	1.0268	7,701.00	7,500	1.2323	9,242.25	1,541.25	20.01%	2.72%
	Low Voltage Rider (kW)	7,500	0.557	4,177.50	7,500	0.5635	4,226.25	48.75	1.17%	1.24%
	Stranded Meters Rate Rider ($/Customer)			2.50			2.37	(0.13)	(5.20%)	0.00%
	LRAM & SSM Rider (kW)	7,500		0.00	7,500	0.0149	112.01	112.01		0.03%
	Smart Meter Rate Rider ($/Customer)			0.00			0.05	0.05		0.00%
	Late Payment (kWh)	1	47.3900	47.39	1	0.0000	0.00	(47.39)	(100.00%)	0.00%
	Deferrral & Variance Acct (kW)	7,500	0.6757	5,067.75	7,500	(0.2836)	(2,126.66)	(7,194.41)	(141.96%)	(0.62%)
	Distribution Sub-Total			**18,763.04**			**14,074.11**	**(4,688.93)**	**(24.99%)**	**4.14%**
	Retail Transmisssion (kW)	7,500	4.0594	30,445.50	7,500	4.16254195	31,219.06	773.56	2.54%	9.17%
	Delivery Sub-Total			**49,208.54**			**45,293.17**	**(3,915.37)**	**(7.96%)**	**13.31%**
	Other Charges (kWh)	3,267,710	0.0131	42,890.27	3,275,233	0.0131	42,989.01	98.74	0.23%	12.63%
	Cost of Power Commodity (kWh)	3,267,710	0.0650	212,401.15	3,275,233	0.0650	212,890.14	488.99	0.23%	62.56%
	SPC (kWh)	3,267,710	0.0000	0.00	3,267,710	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**304,499.96**			**301,172.33**	**(3,327.63)**	**(1.09%)**	**88.50%**
	GST		13.00%	39,585.00		13.00%	39,152.40	(432.59)	(1.09%)	11.50%
	Total Bill			**344,084.96**			**340,324.74**	**(3,760.22)**	**(1.09%)**	**100.00%**

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Consumption		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
4,200,000 kWh	Monthly Service Charge			1,766.90			2,617.84	850.94	48.16%	0.57%
10,000 kW	Distribution (kW)	10,000	1.0268	10,268.00	10,000	1.2323	12,323.00	2,055.00	20.01%	2.68%
	Low Voltage Rider (kW)	10,000	0.557	5,570.00	10,000	0.5635	5,635.00	65.00	1.17%	1.23%
	Stranded Meters Rate Rider ($/Customer)			2.50			2.37	(0.13)	(5.20%)	0.00%
	LRAM & SSM Rider (kW)	10,000		0.00	10,000	0.0149	149.35	149.35		0.03%
	Smart Meter Rate Rider ($/Customer)			0.00			0.05	0.05		0.00%
	Late Payment (kWh)	1	47.3900	47.39	1	0.0000	0.00	(47.39)	(100.00%)	0.00%
	Deferrral & Variance Acct (kW)	10,000	0.6757	6,757.00	10,000	(0.2836)	(2,835.55)	(9,592.55)	(141.96%)	(0.62%)
	Distribution Sub-Total			**24,411.79**			**17,892.06**	**(6,519.73)**	**(26.71%)**	**3.90%**
	Retail Transmisssion (kW)	10,000	4.0594	40,594.00	10,000	4.16254195	41,625.42	1,031.42	2.54%	9.07%
	Delivery Sub-Total			**65,005.79**			**59,517.48**	**(5,488.31)**	**(8.44%)**	**12.97%**
	Other Charges (kWh)	4,427,220	0.0131	58,109.40	4,437,412	0.0131	58,243.18	133.78	0.23%	12.69%
	Cost of Power Commodity (kWh)	4,427,220	0.0650	287,769.30	4,437,412	0.0650	288,431.81	662.51	0.23%	62.84%
	SPC (kWh)	4,427,220	0.0000	0.00	4,427,220	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**410,884.49**			**406,192.47**	**(4,692.02)**	**(1.14%)**	**88.50%**
	GST		13.00%	53,414.98		13.00%	52,805.02	(609.96)	(1.14%)	11.50%
	Total Bill			**464,299.47**			**458,997.49**	**(5,301.98)**	**(1.14%)**	**100.00%**

GS 3000 - 4999

Consumption
4,700,000 kWh
13,900 kW

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			1,766.90			2,617.84	850.94	48.16%	0.49%
Distribution (kW)	13,900	1.0268	14,272.52	13,900	1.2323	17,128.97	2,856.45	20.01%	3.23%
Low Voltage Rider (kW)	13,900	0.557	7,742.30	13,900	0.5635	7,832.65	90.35	1.17%	1.48%
Stranded Meters Rate Rider ($/Customer)			2.50			2.37	(0.13)	(5.20%)	0.00%
LRAM & SSM Rider (kW)	13,900		0.00	13,900	0.0149	207.59	207.59		0.04%
Smart Meter Rate Rider ($/Customer)			0.00			0.05	0.05		0.00%
Late Payment (kWh)	1	47.3900	47.39	1	0.0000	0.00	(47.39)	(100.00%)	0.00%
Deferrral & Variance Acct (kW)	13,900	0.6757	9,392.23	13,900	(0.2836)	(3,941.41)	(13,333.64)	(141.96%)	(0.74%)
Distribution Sub-Total			**33,223.84**			**23,848.06**	**(9,375.78)**	**(28.22%)**	**4.49%**
Retail Transmisssion (kW)	13,900	4.0594	56,425.66	13,900	4.16254195	57,859.33	1,433.67	2.54%	10.90%
Delivery Sub-Total			**89,649.50**			**81,707.39**	**(7,942.11)**	**(8.86%)**	**15.40%**
Other Charges (kWh)	4,954,270	0.0131	65,027.19	4,965,676	0.0131	65,176.89	149.71	0.23%	12.28%
Cost of Power Commodity (kWh)	4,954,270	0.0650	322,027.55	4,965,676	0.0650	322,768.93	741.38	0.23%	60.82%
SPC (kWh)	4,954,270	0.0000	0.00	4,954,270	0.0000	0.00	0.00		0.00%
Total Bill Before Taxes			**476,704.24**			**469,653.22**	**(7,051.02)**	**(1.48%)**	**88.50%**
GST		13.00%	61,971.55		13.00%	61,054.92	(916.63)	(1.48%)	11.50%
Total Bill			**538,675.79**			**530,708.13**	**(7,967.65)**	**(1.48%)**	**100.00%**

Street Lighting

Billing Determinants
2,804 Connections
101,298 kWh
279 kW

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge	2,804	3.8400	10,766.21	2,804	3.2591	9,137.54	(1,628.67)	(15.13%)	33.06%
Distribution (kW)	279	24.3414	6,781.79	279	20.6590	5,755.83	(1,025.96)	(15.13%)	20.82%
Low Voltage Rider (kW)	279	0.3708	103.31	279	0.3694	102.92	(0.39)	(0.38%)	0.37%
LRAM & SSM Rider (kW)	279		0.00	279	0.0000	0.00	0.00		0.00%
Late Payment (kWh)	1	0.0300	0.03	1	0.0000	0.00	(0.03)	(100.00%)	0.00%
Deferrral & Variance Acct (kW)	279	0.2798	77.96	279	1.1889	331.24	253.28	324.91%	1.20%
Distribution Sub-Total			**17,729.29**			**15,327.53**	**(2,401.77)**	**(13.55%)**	**55.45%**
Retail Transmisssion (kW)	279	2.703	753.09	279	2.771761487	772.24	19.16	2.54%	2.79%
Delivery Sub-Total			**18,482.38**			**16,099.77**	**(2,382.61)**	**(12.89%)**	**58.25%**
Other Charges (kWh)	106,778	0.0131	1,401.52	107,024	0.0131	1,404.74	3.23	0.23%	5.08%
Cost of Power Commodity (kWh)	106,778	0.0650	6,940.58	107,024	0.0650	6,956.56	15.98	0.23%	25.17%
SPC (kWh)	106,778	0.0000	0.00	106,778	0.0000	0.00	0.00		0.00%
Total Bill Before Taxes			**26,824.47**			**24,461.07**	**(2,363.40)**	**(8.81%)**	**88.50%**
GST		13.00%	3,487.18		13.00%	3,179.94	(307.24)	(8.81%)	11.50%
Total Bill			**30,311.66**			**27,641.01**	**(2,670.64)**	**(8.81%)**	**100.00%**

Street Lighting

Billing Determinants		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
1 Connections	Monthly Service Charge	1	3.8400	3.84	1	3.2591	3.26	(0.58)	(15.13%)	22.78%
62.47 kWh	Distribution (kW)	0	24.3414	4.14	0	20.6590	3.51	(0.63)	(15.13%)	24.54%
0.17 kW	Low Voltage Rider (kW)	0	0.3708	0.06	0	0.3694	0.06	(0.00)	(0.38%)	0.44%
	LRAM & SSM Rider (kW)	0		0.00	0	0.0000	0.00	0.00		0.00%
	Late Payment (kWh)	1	0.0300	0.03	1	0.0000	0.00	(0.03)	(100.00%)	0.00%
	Deferrral & Variance Acct (kW)	0	0.2798	0.05	0	1.1889	0.20	0.15	324.91%	1.41%
	Distribution Sub-Total			**8.12**			**7.04**	**(1.08)**	**(13.33%)**	**49.17%**
	Retail Transmisssion (kW)	0	2.703	0.46	0	2.771761487	0.47	0.01	2.54%	3.29%
	Delivery Sub-Total			**8.58**			**7.51**	**(1.07)**	**(12.48%)**	**52.46%**
	Other Charges (kWh)	66	0.0131	0.86	66	0.0131	0.87	0.00	0.23%	6.05%
	Cost of Power Commodity (kWh)	66	0.0650	4.28	66	0.0650	4.29	0.01	0.23%	29.98%
	SPC (kWh)	66	0.0000	0.00	66	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**13.72**			**12.66**	**(1.06)**	**(7.72%)**	**88.50%**
	GST		13.00%	1.78		13.00%	1.65	(0.14)	(7.72%)	11.50%
	Total Bill			**15.51**			**14.31**	**(1.20)**	**(7.72%)**	**100.00%**

Sentinel Lighting

Billing Determinants		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
54 Connections	Monthly Service Charge	54	4.6600	250.23	54	4.2957	230.67	(19.56)	(7.82%)	19.95%
6,536 kWh	Distribution (kW)	18	11.4737	208.31	18	10.5767	192.02	(16.29)	(7.82%)	16.61%
18 kW	Low Voltage Rider (kW)	18	0.3754	6.82	18	0.3771	6.85	0.03	0.45%	0.59%
	LRAM & SSM Rider (kW)	18		0.00	18	0.0000	0.00	0.00		0.00%
	Late Payment (kWh)	1	0.0600	0.06	1	0.0000	0.00	(0.06)	(100.00%)	0.00%
	Deferrral & Variance Acct (kW)	18	0.3071	5.58	18	0.1763	3.20	(2.37)	(42.60%)	0.28%
	Distribution Sub-Total			**470.99**			**432.74**	**(38.25)**	**(8.12%)**	**37.43%**
	Retail Transmisssion (kW)	18	2.7353	49.66	18	2.804836696	50.92	1.26	2.54%	4.40%
	Delivery Sub-Total			**520.65**			**483.66**	**(36.99)**	**(7.10%)**	**41.83%**
	Other Charges (kWh)	6,890	0.0131	90.43	6,905	0.0131	90.64	0.21	0.23%	7.84%
	Cost of Power Commodity (kWh)	6,890	0.0650	447.82	6,905	0.0650	448.85	1.03	0.23%	38.82%
	SPC (kWh)	6,890	0.0000	0.00	6,890	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**1,058.90**			**1,023.15**	**(35.75)**	**(3.38%)**	**88.50%**
	GST		13.00%	137.66		13.00%	133.01	(4.65)	(3.38%)	11.50%
	Total Bill			**1,196.56**			**1,156.16**	**(40.40)**	**(3.38%)**	**100.00%**

Sentinel Lighting

Billing Determinants		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
1 Connections	Monthly Service Charge	1	4.6600	4.66	1	4.2957	4.30	(0.36)	(7.82%)	19.41%
134.55 kWh	Distribution (kW)	0	11.4737	3.44	0	10.5767	3.17	(0.27)	(7.82%)	14.34%
0.30 kW	Low Voltage Rider (kW)	0	0.3754	0.11	0	0.3771	0.11	0.00	0.45%	0.51%
	LRAM & SSM Rider (kW)	0		0.00	0	0.0000	0.00	0.00		0.00%
	Late Payment (kWh)	1	0.0600	0.06	1	0.0000	0.00	(0.06)	(100.00%)	0.00%
	Deferrral & Variance Acct (kW)	0	0.3071	0.09	0	0.1763	0.05	(0.04)	(42.60%)	0.24%
	Distribution Sub-Total			**8.37**			**7.63**	**(0.73)**	**(8.75%)**	**34.50%**
	Retail Transmisssion (kW)	0	2.7353	0.82	0	2.804836696	0.84	0.02	2.54%	3.80%
	Delivery Sub-Total			**9.19**			**8.48**	**(0.71)**	**(7.74%)**	**38.31%**
	Other Charges (kWh)	142	0.0131	1.86	142	0.0131	1.87	0.00	0.23%	8.43%
	Cost of Power Commodity (kWh)	142	0.0650	9.22	142	0.0650	9.24	0.02	0.23%	41.76%
	SPC (kWh)	142	0.0000	0.00	142	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**20.27**			**19.58**	**(0.69)**	**(3.38%)**	**88.50%**
	GST		13.00%	2.63		13.00%	2.55	(0.09)	(3.38%)	11.50%
	Total Bill			**22.90**			**22.13**	**(0.77)**	**(3.38%)**	**100.00%**

Unmetered Scattered

		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			11.22			15.79	4.57	40.73%	28.05%
250 kWh	Distribution (kWh)	250	0.0293	7.33	250	0.0412	10.30	2.98	40.61%	18.30%
	Low Voltage Rider (kWh)	250	0.0014	0.35	250	0.0015	0.38	0.03	7.14%	0.67%
	LRAM & SSM Rider (kWh)	250	0.0000	0.00	250	0.0000	0.00	0.00		0.00%
	Late Payment (kWh)	1	0.2800	0.28	250	0.0000	0.00	(0.28)	(100.00%)	0.00%
	Deferrral & Variance Acct (kWh)	250	0.0011	0.28	250	(0.0005)	(0.12)	(0.40)	(144.31%)	(0.22%)
	Distribution Sub-Total			**19.45**			**26.34**	**6.89**	**35.44%**	**46.79%**
	Retail Transmisssion (kWh)	264	0.0105	2.77	264	0.010766428	2.84	0.08	2.77%	5.05%
	Delivery Sub-Total			**22.22**			**29.19**	**6.97**	**31.37%**	**51.84%**
	Other Charges (kWh)	264	0.0131	3.46	264	0.0131	3.47	0.01	0.23%	6.16%
	Cost of Power Commodity (kWh)	264	0.0650	17.13	264	0.0650	17.17	0.04	0.23%	30.50%
	SPC (kWh)	264	0.0000	0.00	264	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**42.81**			**49.82**	**6.94**	**16.21%**	**88.50%**
	GST		13.00%	5.56		13.00%	6.48	0.91	16.39%	11.50%
	Total Bill			**48.37**			**56.30**	**7.85**	**16.23%**	**100.00%**

Unmetered Scattered

		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			11.22			15.79	4.57	40.73%	4.85%
2,000 kWh	Distribution (kWh)	2,000	0.0293	58.60	2,000	0.0412	82.40	23.80	40.61%	25.32%
	Low Voltage Rider (kWh)	2,000	0.0014	2.80	2,000	0.0015	3.00	0.20	7.14%	0.92%
	LRAM & SSM Rider (kWh)	2,000	0.0000	0.00	2,000	0.0000	0.00	0.00		0.00%
	Late Payment (kWh)	1	0.2800	0.28	2,000	0.0000	0.00	(0.28)	(100.00%)	0.00%
	Deferrral & Variance Acct (kWh)	2,000	0.0011	2.20	2,000	(0.0005)	(0.97)	(3.17)	(144.31%)	(0.30%)
	Distribution Sub-Total			**75.10**			**100.21**	**25.11**	**33.44%**	**30.79%**
	Retail Transmisssion (kWh)	2,108	0.0105	22.14	2,113	0.010766428	22.75	0.61	2.77%	6.99%
	Delivery Sub-Total			**97.24**			**122.96**	**25.73**	**26.46%**	**37.78%**
	Other Charges (kWh)	2,108	0.0131	27.67	2,113	0.0131	27.73	0.06	0.23%	8.52%
	Cost of Power Commodity (kWh)	2,108	0.0650	137.03	2,113	0.0650	137.35	0.32	0.23%	42.20%
	SPC (kWh)	2,108	0.0000	0.00	2,108	0.0000	0.00	0.00		0.00%
	Total Bill Before Taxes			**261.94**			**288.05**	**25.49**	**9.73%**	**88.50%**
	GST		13.00%	34.05		13.00%	37.45	3.39	9.97%	11.50%
	Total Bill			**295.99**			**325.49**	**28.89**	**9.76%**	**100.00%**

APPENDIX B RTSR BOARD MODEL

Rate Class	Unit	RTSR - Network	RTSR - Connection
Residential	kWh	$ 0.0054	$ 0.0043
General Service Less Than 50 kW	kWh	$ 0.0049	$ 0.0039
General Service 50 to 2,999 kW	kW	$ 1.9987	$ 1.5466
General Service 3,000 to 4,999 kW	kW	$ 2.2353	$ 1.8241
Unmetered Scattered Load	kWh	$ 0.0057	$ 0.0048
Sentinel Lighting	kW	$ 1.5148	$ 1.2205
Street Lighting	kW	$ 1.5074	$ 1.1956
Choose Rate Class	kWh	$ 1.9987	$ 1.5466
Choose Rate Class	kWh	$ 2.2353	$ 1.8241
Choose Rate Class	kWh	$ 1.5148	$ 1.2205
Choose Rate Class	kWh	$ 1.5074	$ 1.1956
Choose Rate Class			
Choose Rate Class			

Rate Class	Unit	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor	Load Factor	Loss Adjusted Billed kWh	Billed kW
Residential	kWh	71,617,895		1.0541		75,492,423	-
General Service Less Than 50 kW	kWh	34,136,417		1.0541		35,983,197	-
General Service 50 to 2,999 kW	kW	120,251,065	300,323		54.88%	120,251,065	300,323
General Service 3,000 to 4,999 kW	kW	19,165,415	46,435		56.57%	19,165,415	46,435
Unmetered Scattered Load	kWh	718,651		1.0541		757,530	-
Sentinel Lighting	kW	46,220	128		49.49%	46,220	128
Street Lighting	kW	1,222,485	3,396		49.34%	1,222,485	3,396

Uniform Transmission Rates	Unit	Effective	Effective	Effective
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	**$ 2.97**	**$ 3.22**	**$ 3.22**
Line Connection Service Rate	kW	**$ 0.73**	**$ 0.79**	**$ 0.79**
Transformation Connection Service Rate	kW	**$ 1.71**	**$ 1.77**	**$ 1.77**

Hydro One Sub-Transmission Rates	Unit	Effective	Effective	Effective
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	**$ 2.65**	**$ 2.65**	**$ 2.65**
Line Connection Service Rate	kW	**$ 0.64**	**$ 0.64**	**$ 0.64**
Transformation Connection Service Rate	kW	**$ 1.50**	**$ 1.50**	**$ 1.50**
Both Line and Transformation Connection Service Rate	kW	**$ 2.14**	**$ 2.14**	**$ 2.14**

Hydro One Sub-Transmission Rate Rider 6A	Unit	Effective	Effective	Effective
Rate Description		**Rate**	**Rate**	**Rate**
RSVA Transmission network – 4714 – which affects 1584	kW	**$ 0.0470**	**$ 0.0470**	**$ 0.0470**
RSVA Transmission connection – 4716 – which affects 1586	kW	**-$ 0.0250**	**-$ 0.0250**	**-$ 0.0250**
RSVA LV – 4750 – which affects 1550	kW	**$ 0.0580**	**$ 0.0580**	**$ 0.0580**
RARA 1 – 2252 – which affects 1590	kW	**-$ 0.0750**	**-$ 0.0750**	**-$ 0.0750**
Hydro One Sub-Transmission Rate Rider 6A	kW	**$ 0.0050**	**$ 0.0050**	**$ 0.0050**

HYDRO ONE

Month	Network			Line Connection			Transformation Connection			Total Line
	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	43,204	$2.24	$ 96,777	43,204	$0.00		43,204	$1.99	$ 85,976	$ 85,976
February	41,809	$2.24	$ 93,652	41,809	$0.00		41,809	$1.99	$ 83,200	$ 83,200
March	39,317	$2.24	$ 88,070	39,317	$0.00		39,317	$1.99	$ 78,241	$ 78,241
April	36,164	$2.30	$ 83,188	36,164	$0.00		36,164	$2.01	$ 72,764	$ 72,764
May	40,939	$2.65	$ 108,488	40,939	$0.00		40,939	$2.14	$ 87,609	$ 87,609
June	42,723	$2.65	$ 113,216	42,723	$0.00		42,723	$2.14	$ 91,427	$ 91,427
July	45,480	$2.65	$ 120,522	45,480	$0.00		45,480	$2.14	$ 97,327	$ 97,327
August	44,365	$2.65	$ 117,567	44,365	$0.00		44,365	$2.14	$ 94,941	$ 94,941
September	41,672	$2.65	$ 110,431	41,672	$0.00		41,672	$2.14	$ 89,178	$ 89,178
October	35,080	$2.65	$ 92,962	35,080	$0.00		35,080	$2.14	$ 75,071	$ 75,071
November	39,259	$2.65	$ 104,036	39,259	$0.00		39,259	$2.14	$ 84,014	$ 84,014
December	44,309	$2.65	$ 117,419	44,309	$0.00		44,309	$2.14	$ 94,821	$ 94,821
Total	494,321	$ 2.52	$ 1,246,329	494,321	$ -	$ -	494,321	$ 2.09	$ 1,034,571	$ 1,034,571

TOTAL

Month	Network			Line Connection			Transformation Connection			Total Line
	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	43,204	$2.24	$ 96,777	43,204	$0.00	$ -	43,204	$1.99	$ 85,976	$ 85,976
February	41,809	$2.24	$ 93,652	41,809	$0.00	$ -	41,809	$1.99	$ 83,200	$ 83,200
March	39,317	$2.24	$ 88,070	39,317	$0.00	$ -	39,317	$1.99	$ 78,241	$ 78,241
April	36,164	$2.30	$ 83,188	36,164	$0.00	$ -	36,164	$2.01	$ 72,764	$ 72,764
May	40,939	$2.65	$ 108,488	40,939	$0.00	$ -	40,939	$2.14	$ 87,609	$ 87,609
June	42,723	$2.65	$ 113,216	42,723	$0.00	$ -	42,723	$2.14	$ 91,427	$ 91,427
July	45,480	$2.65	$ 120,522	45,480	$0.00	$ -	45,480	$2.14	$ 97,327	$ 97,327
August	44,365	$2.65	$ 117,567	44,365	$0.00	$ -	44,365	$2.14	$ 94,941	$ 94,941
September	41,672	$2.65	$ 110,431	41,672	$0.00	$ -	41,672	$2.14	$ 89,178	$ 89,178
October	35,080	$2.65	$ 92,962	35,080	$0.00	$ -	35,080	$2.14	$ 75,071	$ 75,071
November	39,259	$2.65	$ 104,036	39,259	$0.00	$ -	39,259	$2.14	$ 84,014	$ 84,014
December	44,309	$2.65	$ 117,419	44,309	$0.00	$ -	44,309	$2.14	$ 94,821	$ 94,821
Total	494,321	$ 2.52	$ 1,246,329	494,321	$ -	$ -	494,321	$ 2.09	$ 1,034,571	$ 1,034,571

HYDRO ONE

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	43,204	$ 2.6970	$ 116,521	43,204	$ 0.6150	$ 26,570	43,204	$ 1.5000	$ 64,806	$ 91,376
February	41,809	$ 2.6970	$ 112,759	41,809	$ 0.6150	$ 25,713	41,809	$ 1.5000	$ 62,714	$ 88,426
March	39,317	$ 2.6970	$ 106,038	39,317	$ 0.6150	$ 24,180	39,317	$ 1.5000	$ 58,976	$ 83,155
April	36,164	$ 2.6970	$ 97,534	36,164	$ 0.6150	$ 22,241	36,164	$ 1.5000	$ 54,246	$ 76,487
May	40,939	$ 2.6970	$ 110,412	40,939	$ 0.6150	$ 25,177	40,939	$ 1.5000	$ 61,409	$ 86,586
June	42,723	$ 2.6970	$ 115,224	42,723	$ 0.6150	$ 26,275	42,723	$ 1.5000	$ 64,085	$ 90,359
July	45,480	$ 2.6970	$ 122,660	45,480	$ 0.6150	$ 27,970	45,480	$ 1.5000	$ 68,220	$ 96,190
August	44,365	$ 2.6970	$ 119,652	44,365	$ 0.6150	$ 27,284	44,365	$ 1.5000	$ 66,548	$ 93,832
September	41,672	$ 2.6970	$ 112,389	41,672	$ 0.6150	$ 25,628	41,672	$ 1.5000	$ 62,508	$ 88,136
October	35,080	$ 2.6970	$ 94,611	35,080	$ 0.6150	$ 21,574	35,080	$ 1.5000	$ 52,620	$ 74,194
November	39,259	$ 2.6970	$ 105,882	39,259	$ 0.6150	$ 24,144	39,259	$ 1.5000	$ 58,889	$ 83,033
December	44,309	$ 2.6970	$ 119,501	44,309	$ 0.6150	$ 27,250	44,309	$ 1.5000	$ 66,464	$ 93,714
Total	494,321	$ 2.70	$ 1,333,184	494,321	$ 0.62	$ 304,007	494,321	$ 1.50	$ 741,482	$ 1,045,489

TOTAL

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	43,204	$ 2.70	$ 116,521	43,204	$ 0.62	$ 26,570	43,204	$ 1.50	$ 64,806	$ 91,376
February	41,809	$ 2.70	$ 112,759	41,809	$ 0.62	$ 25,713	41,809	$ 1.50	$ 62,714	$ 88,426
March	39,317	$ 2.70	$ 106,038	39,317	$ 0.62	$ 24,180	39,317	$ 1.50	$ 58,976	$ 83,155
April	36,164	$ 2.70	$ 97,534	36,164	$ 0.62	$ 22,241	36,164	$ 1.50	$ 54,246	$ 76,487
May	40,939	$ 2.70	$ 110,412	40,939	$ 0.62	$ 25,177	40,939	$ 1.50	$ 61,409	$ 86,586
June	42,723	$ 2.70	$ 115,224	42,723	$ 0.62	$ 26,275	42,723	$ 1.50	$ 64,085	$ 90,359
July	45,480	$ 2.70	$ 122,660	45,480	$ 0.62	$ 27,970	45,480	$ 1.50	$ 68,220	$ 96,190
August	44,365	$ 2.70	$ 119,652	44,365	$ 0.62	$ 27,284	44,365	$ 1.50	$ 66,548	$ 93,832
September	41,672	$ 2.70	$ 112,389	41,672	$ 0.62	$ 25,628	41,672	$ 1.50	$ 62,508	$ 88,136
October	35,080	$ 2.70	$ 94,611	35,080	$ 0.62	$ 21,574	35,080	$ 1.50	$ 52,620	$ 74,194
November	39,259	$ 2.70	$ 105,882	39,259	$ 0.62	$ 24,144	39,259	$ 1.50	$ 58,889	$ 83,033
December	44,309	$ 2.70	$ 119,501	44,309	$ 0.62	$ 27,250	44,309	$ 1.50	$ 66,464	$ 93,714
Total	494,321	$ 2.70	$ 1,333,184	494,321	$ 0.62	$ 304,007	494,321	$ 1.50	$ 741,482	$ 1,045,489

HYDRO ONE

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	43,204	$ 2.6970	$ 116,521	43,204	$ 0.6150	$ 26,570	43,204	$ 1.5000	$ 64,806	$ 91,376
February	41,809	$ 2.6970	$ 112,759	41,809	$ 0.6150	$ 25,713	41,809	$ 1.5000	$ 62,714	$ 88,426
March	39,317	$ 2.6970	$ 106,038	39,317	$ 0.6150	$ 24,180	39,317	$ 1.5000	$ 58,976	$ 83,155
April	36,164	$ 2.6970	$ 97,534	36,164	$ 0.6150	$ 22,241	36,164	$ 1.5000	$ 54,246	$ 76,487
May	40,939	$ 2.6970	$ 110,412	40,939	$ 0.6150	$ 25,177	40,939	$ 1.5000	$ 61,409	$ 86,586
June	42,723	$ 2.6970	$ 115,224	42,723	$ 0.6150	$ 26,275	42,723	$ 1.5000	$ 64,085	$ 90,359
July	45,480	$ 2.6970	$ 122,660	45,480	$ 0.6150	$ 27,970	45,480	$ 1.5000	$ 68,220	$ 96,190
August	44,365	$ 2.6970	$ 119,652	44,365	$ 0.6150	$ 27,284	44,365	$ 1.5000	$ 66,548	$ 93,832
September	41,672	$ 2.6970	$ 112,389	41,672	$ 0.6150	$ 25,628	41,672	$ 1.5000	$ 62,508	$ 88,136
October	35,080	$ 2.6970	$ 94,611	35,080	$ 0.6150	$ 21,574	35,080	$ 1.5000	$ 52,620	$ 74,194
November	39,259	$ 2.6970	$ 105,882	39,259	$ 0.6150	$ 24,144	39,259	$ 1.5000	$ 58,889	$ 83,033
December	44,309	$ 2.6970	$ 119,501	44,309	$ 0.6150	$ 27,250	44,309	$ 1.5000	$ 66,464	$ 93,714
Total	494,321	$ 2.70	$ 1,333,184	494,321	$ 0.62	$ 304,007	494,321	$ 1.50	$ 741,482	$ 1,045,489

TOTAL

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	43,204	$ 2.70	$ 116,521	43,204	$ 0.62	$ 26,570	43,204	$ 1.50	$ 64,806	$ 91,376
February	41,809	$ 2.70	$ 112,759	41,809	$ 0.62	$ 25,713	41,809	$ 1.50	$ 62,714	$ 88,426
March	39,317	$ 2.70	$ 106,038	39,317	$ 0.62	$ 24,180	39,317	$ 1.50	$ 58,976	$ 83,155
April	36,164	$ 2.70	$ 97,534	36,164	$ 0.62	$ 22,241	36,164	$ 1.50	$ 54,246	$ 76,487
May	40,939	$ 2.70	$ 110,412	40,939	$ 0.62	$ 25,177	40,939	$ 1.50	$ 61,409	$ 86,586
June	42,723	$ 2.70	$ 115,224	42,723	$ 0.62	$ 26,275	42,723	$ 1.50	$ 64,085	$ 90,359
July	45,480	$ 2.70	$ 122,660	45,480	$ 0.62	$ 27,970	45,480	$ 1.50	$ 68,220	$ 96,190
August	44,365	$ 2.70	$ 119,652	44,365	$ 0.62	$ 27,284	44,365	$ 1.50	$ 66,548	$ 93,832
September	41,672	$ 2.70	$ 112,389	41,672	$ 0.62	$ 25,628	41,672	$ 1.50	$ 62,508	$ 88,136
October	35,080	$ 2.70	$ 94,611	35,080	$ 0.62	$ 21,574	35,080	$ 1.50	$ 52,620	$ 74,194
November	39,259	$ 2.70	$ 105,882	39,259	$ 0.62	$ 24,144	39,259	$ 1.50	$ 58,889	$ 83,033
December	44,309	$ 2.70	$ 119,501	44,309	$ 0.62	$ 27,250	44,309	$ 1.50	$ 66,464	$ 93,714
Total	494,321	$ 2.70	$ 1,333,184	494,321	$ 0.62	$ 304,007	494,321	$ 1.50	$ 741,482	$ 1,045,489

Rate Class	Unit	Current RTSR - Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR Network
Residential	kWh	$ 0.0054	75,492,423	-	$ 407,659	31.4%	$ 418,819	$ 0.0055
General Service Less Than 50 kW	kWh	$ 0.0049	35,983,197	-	$ 176,318	13.6%	$ 181,144	$ 0.0050
General Service 50 to 2,999 kW	kW	$ 1.9987	120,251,065	300,323	$ 600,256	46.3%	$ 616,688	$ 2.0534
General Service 3,000 to 4,999 kW	kW	$ 2.2353	19,165,415	46,435	$ 103,796	8.0%	$ 106,638	$ 2.2965
Unmetered Scattered Load	kWh	$ 0.0057	757,530	-	$ 4,318	0.3%	$ 4,436	$ 0.0059
Sentinel Lighting	kW	$ 1.5148	46,220	128	$ 194	0.0%	$ 199	$ 1.5563
Street Lighting	kW	$ 1.5074	1,222,485	3,396	$ 5,119	0.4%	$ 5,259	$ 1.5487
					$ 1,297,659			

1
2

Rate Class	Unit	Current RTSR - Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR Connection
Residential	kWh	$ 0.0043	75,492,423	-	$ 324,617	31.8%	$ 332,083	$ 0.0044
General Service Less Than 50 kW	kWh	$ 0.0039	35,983,197	-	$ 140,334	13.7%	$ 143,562	$ 0.0040
General Service 50 to 2,999 kW	kW	$ 1.5466	120,251,065	300,323	$ 464,480	45.4%	$ 475,161	$ 1.5822
General Service 3,000 to 4,999 kW	kW	$ 1.8241	19,165,415	46,435	$ 84,702	8.3%	$ 86,650	$ 1.8660
Unmetered Scattered Load	kWh	$ 0.0048	757,530	-	$ 3,636	0.4%	$ 3,720	$ 0.0049
Sentinel Lighting	kW	$ 1.2205	46,220	128	$ 156	0.0%	$ 160	$ 1.2486
Street Lighting	kW	$ 1.1956	1,222,485	3,396	$ 4,060	0.4%	$ 4,154	$ 1.2231
					$ 1,021,986			

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Rate Class	Unit	Adjusted RTSR - Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Network
Residential	kWh	$ 0.0055	75,492,423	-	$ 418,819	31.4%	$ 418,819	$ 0.0055
General Service Less Than 50 kW	kWh	$ 0.0050	35,983,197	-	$ 181,144	13.6%	$ 181,144	$ 0.0050
General Service 50 to 2,999 kW	kW	$ 2.0534	120,251,065	300,323	$ 616,688	46.3%	$ 616,688	$ 2.0534
General Service 3,000 to 4,999 kW	kW	$ 2.2965	19,165,415	46,435	$ 106,638	8.0%	$ 106,638	$ 2.2965
Unmetered Scattered Load	kWh	$ 0.0059	757,530	-	$ 4,436	0.3%	$ 4,436	$ 0.0059
Sentinel Lighting	kW	$ 1.5563	46,220	128	$ 199	0.0%	$ 199	$ 1.5563
Street Lighting	kW	$ 1.5487	1,222,485	3,396	$ 5,259	0.4%	$ 5,259	$ 1.5487
					$ 1,333,184			

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Rate Class	Unit	Adjusted RTSR - Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Connection
Residential	kWh	$ 0.0044	75,492,423	-	$ 332,083	31.8%	$ 332,083	$ 0.0044
General Service Less Than 50 kW	kWh	$ 0.0040	35,983,197	-	$ 143,562	13.7%	$ 143,562	$ 0.0040
General Service 50 to 2,999 kW	kW	$ 1.5822	120,251,065	300,323	$ 475,161	45.4%	$ 475,161	$ 1.5822
General Service 3,000 to 4,999 kW	kW	$ 1.8660	19,165,415	46,435	$ 86,650	8.3%	$ 86,650	$ 1.8660
Unmetered Scattered Load	kWh	$ 0.0049	757,530	-	$ 3,720	0.4%	$ 3,720	$ 0.0049
Sentinel Lighting	kW	$ 1.2486	46,220	128	$ 160	0.0%	$ 160	$ 1.2486
Street Lighting	kW	$ 1.2231	1,222,485	3,396	$ 4,154	0.4%	$ 4,154	$ 1.2231
					$ 1,045,489			

1

For Cost of Service Applicants, please enter the following Proposed RTS rates into your rates model.

For IRM applicants, please enter these rates into the 2012 Rate Generator.

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0055	$ 0.0044
General Service Less Than 50 kW	kWh	$ 0.0050	$ 0.0040
General Service 50 to 2,999 kW	kW	$ 2.0534	$ 1.5822
General Service 3,000 to 4,999 kW	kW	$ 2.2965	$ 1.8660
Unmetered Scattered Load	kWh	$ 0.0059	$ 0.0049
Sentinel Lighting	kW	$ 1.5563	$ 1.2486
Street Lighting	kW	$ 1.5487	$ 1.2231

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DEFERRAL AND VARIANCE ACCOUNTS

OVERVIEW

The information contained in this exhibit includes the status and description of LUI'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.

The deferral and variance accounts are accounted for in accordance with the Accounting Procedures Handbook. LUI has prepared the information included in this application based on the guidelines provided in the Report of the Board on Electricity Distributor's Deferral and Variance Account Review Initiative (EDDVAR). LUI received approval from the Board to recover its Group 1 deferral and variance account balances accumulated to December 31, 2009 in its 2011 Incentive Regulation Mechanism Distribution Rate Adjustment. The approved balances and the related interest were transferred to a subaccount of 1595. The corresponding rate riders for the recovery/refund of the approved balances are effective until April 30, 2012. The deferral and variance accounts which have outstanding balances at December 31, 2010 have been identified and described below. The accounts have been divided into two groupings in accordance with the Report of the Board on Electricity Distributor's Deferral and Variance Account Review Initiative (EDDVAR). Unless otherwise stated, LUI is applying for disposition of all account balances as at December 31, 2010

The following Table 9-0 contains account balances in the column labeled "Total" from the 2010 Audited Financial Statements as at December 31, 2010 and agrees to the 2010 year end balances for RRR filing E2.1.7 Trial Balance as filed April 30, 2011 with the OEB. In the last column, the Table 9-0 shows the claims being requested for disposition in this Cost of Service.

LUI asserts that the Group 1 accounts requested for disposition in this filing reflect only those transactions/activities for the year 2010 and interest projected to April 30, 2012.

Table 9-1 that follows shows the interest rates that have been used in the calculation of carrying charges on the accounts in accordance with the methodology approved by the Board.

Table 9-0 DEFERRAL AND VARIANCE ACCOUNT BALANCES DECEMBER 31,2010

DEFERRAL AND VARIANCE ACCOUNT BALANCES AS AT DECEMBER 31, 2010					
Account Number	Account Name	Closing Principal Balance as of Dec-31-10	Closing Interest Amounts as of Dec-31-10	TOTAL	CLAIM (including all dispositions and interest forecasts)
Group One					
1550	LV Variance Account	-$ 233,080	-$ 1,623	**-$ 234,703**	**(101,408)**
1580	RSVA - Wholesale Market Service Charge	-$ 323,165	-$ 2,205	**-$ 325,370**	**(263,623)**
1584	RSVA - Retail Transmission Network Charge	$ 28,725	-$ 3	**$ 28,722**	**26,403**
1586	RSVA - Retail Transmission Connection Charge	$ 41,559	$ 288	**$ 41,847**	**31,723**
1588	RSVA - Power (excluding Global Adjustment)	$ 91,442	$ 46,185	**$ 137,627**	**(411,307)**
1588	RSVA - Power - Sub-Account - Global Adjustment	-$ 60,148	-$ 3,674	**-$ 63,822**	**(115,424)**
1590	Recovery of Regulatory Asset Balances	$ 14,919	-$ 14,919	**$ -**	**292**
1595	Disposition and Recovery of Regulatory Balances (2008)10	-$ 3,552	$ 3,552	**$ -**	**(70)**
1595	Disposition and Recovery of Regulatory Balances (2009)10	-$ 224,685	-$ 599	**-$ 225,284**	**(229,688)**
			$ -	**$ -**	
	Group 1 Sub-Total (including Account 1588 - Global Adjustment)	**-$ 667,985**	**$ 27,002**	**-$ 640,983**	**(1,063,102)**
	Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)	**-$ 607,837**	**$ 30,676**	**-$ 577,161**	**(947,678)**
1588	RSVA - Power - Sub-Account - Global Adjustment	-$ 60,148	-$ 3,674	**-$ 63,822**	**(115,424)**
		$ -	$ -	**$ -**	**-**
Group Two		$ -	$ -	**$ -**	**-**
1508	Other Regulatory Assets - Sub-Account - OEB Cost Assessments	-$ 0	$ 0	**$ 0**	**0**
1508	Other Regulatory Assets - Sub-Account - Pension Contributions	$ 0	-$ 0	**-$ 0**	**(0)**
1508	Other Regulatory Assets - IFRS	$ -	$ -	**$ -**	**-**
1508	Other Regulatory Assets	$ -	$ -	**$ -**	**-**
1508	Other Regulatory Assets - Other	$ 9,158	$ 83	**$ 9,242**	**9,421**
1518	Retail Cost Variance Account - Retail	$ 43,281	$ 1,017	**$ 44,297**	**45,145**
1525	Miscellaneous Deferred Debits	$ 36,872	$ -	**$ 36,872**	**37,595**
1531	RCCDA	$ -	$ -	**$ -**	**-**
1532	RCOM&A DA	$ -	$ -	**$ -**	**-**
1533	Renewable Generation Connection Funding Adder Deferral Account	$ -	$ -	**$ -**	**-**
1534	Smart Grid Capital Deferral Account	$ -	$ -	**$ -**	**-**
1535	Smart Grid OM&A Deferral Account	$ -	$ -	**$ -**	**-**
1536	Smart Grid Funding Adder Deferral Account	$ -	$ -	**$ -**	**-**
1548	Retail Cost Variance Account - STR	$ 36,223	$ 4,185	**$ 40,408**	**41,118**
1555	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	$ 1,714,130	$ 10,020	**$ 1,724,150**	**1,757,747**
1555	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Interest/Recoveries	-$ 419,071	-$ 3,637	**-$ 422,709**	**(430,922)**
1555	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	$ -	$ -	**$ -**	**-**
1556	Smart Meter OM&A Variance	$ 76,300	$ 425	**$ 76,725**	**78,221**
1565	CDM	$ 0	$ -	**$ 0**	**0**
1566	CDM Contra	-$ 0	$ -	**-$ 0**	**(0)**
1570	Qualifying Transition Costs 5	$ -	$ -	**$ -**	**-**
1571	Pre-market Opening Energy Variance 5	$ -	$ -	**$ -**	**-**
1572	Extra-Ordinary Event Costs	$ -	$ -	**$ -**	**-**
1574	Deferred Rate Impact Amounts	$ -	$ -	**$ -**	**-**
1582	Onetime WMS Account	$ 30,359	-$ 12,367	**$ 17,992**	**18,587**
2425	Other Deferred Credits	$ -	$ -	**$ -**	**-**
		$ -	$ -	**$ -**	**-**
	Group 2 Sub-Total	**$ 1,527,251**	**-$ 274**	**$ 1,526,977**	**1,556,911**
Other		$ -	$ -	**$ -**	**(97,487)**
1562	Deferred Payments in Lieu of Taxes	-$ 70,320	-$ 27,166	**-$ 97,486**	**(97,486)**
1592	PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	$ -	$ -	**$ -**	**-**
1592	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	$ 31,574	$ -	**$ 31,574**	**31,574**
		$ -	$ -	**$ -**	**-**
	Total including Group 1 & Group 2	$ 859,266	$ 26,728	**$ 885,994**	**427,897**
		$ -	$ -	**$ -**	**-**
		$ -	$ -	**$ -**	**-**
1521	Special Purpose Charge Assessment Variance Account	$ -	$ -	**$ -**	**-**
		$ -	$ -	**$ -**	**-**
		$ -	$ -	**$ -**	**-**
	Total including Account 1521 1	$ 859,266	$ 26,728	**$ 885,994**	**427,897**
		$ -	$ -	**$ -**	**-**
	The following is not included in the total claim but are included on a memo basis:	$ -	$ -	**$ -**	**97,487**
1563	PILS Contra	$ 70,320	$ 27,166	**$ 97,486**	**97,486**
1567		$ -	$ -	**$ -**	**-**
1592	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	-$ 31,574	$ -	**-$ 31,574**	**(31,574)**
1595	Disposition and Recovery of Regulatory Balances10	$ -	$ -	**$ -**	**-**

Table 9-1 Interest Rates Applied (in %)

	Account 1508	All Other Accounts
Q3 2011 - Note A	1.47	1.47
Q2 2011	1.47	1.47
Q1 2011	1.47	1.47
Q4 2010	1.20	1.20
Q3 2010	0.89	0.89
Q2 2010	0.55	0.55
Q1 2010	0.55	0.55
Q4 2009	0.55	0.55
Q3 2009	0.55	0.55
Q2 2009	1.00	1.00
Q1 2009	2.45	2.45
Q4 2008	3.35	3.35
Q3 2008	3.35	3.35
Q2 2008	4.08	4.08
Q1 2008	5.14	5.14
Q4 2007	5.14	5.14
Q3 2007	4.59	4.59
Q2 2007	4.59	4.59
Q1 2007	4.59	4.59
Q4 2006	4.59	4.59
Q3 2006	4.59	4.59
Q2 2006	4.14	4.14
Q1 2006	3.88	7.25
Q4 2005	3.88	7.25
Q3 2005	3.88	7.25
Q2 2005	3.88	7.25
Q1 2005	3.88	7.25

Note A - Rate used in interest projection

GROUP 1 ACCOUNTS

1550 Retail Settlement Variance account – Low Voltage Charges

This account is used to record the net of the amount charged by the host distributor to an embedded distributor and the amount billed to customers based on approved LV rates in accordance with the Accounting Procedures Handbook (APH). LUI 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 2012, LUI is requesting disposition of the December 31, 2010 audited balance, less the 2011 IRM approved disposition amounts plus the forecasted interest through April 30, 2012 for account 1550. The requested amount is a credit of $ -$ 101,408 .

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. LUI 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 2012, LUI is requesting disposition of the December 31, 2010 audited balance, less the 2011 IRM approved disposition amounts plus the forecasted interest through April

30, 2012 for account 1580. The requested amount is a credit of $ -$ 263,623 |

1584 Retail Settlement Variance Account - Retail Transmission Network Charges

This account is used to record the net of the amount charged by the IESO and /or Hydro One, based on the settlement invoice for transmission network services, and the amount billed to customers using the OEB-approved Transmission Network Charge. LUI 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 2012, LUI is requesting disposition of the December 31, 2010 audited balance, less the 2011 IRM approved disposition amounts plus the forecasted interest through April 30, 2012 for account 1584. The requested amount is a debit of $ $ 26,403 |.

1586 Retail Settlement Variance Account - Retail Transmission Connection Charges

This account is used to record the net of the amount charged by the IESO and/or Hydro One, based on the settlement invoice for transmission connection services, and the amount billed to customers using the OEB-approved Transmission Connection Charge. LUI 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 2012, LUI is requesting disposition of the December 31, 2010 audited balance, less the 2011 IRM approved disposition amounts plus the forecasted interest through April 30, 2012 for account 1586. The requested amount is a debit of $ $ 31,723 |.

1588 Retail Settlement Variance Account – Power

This account is used to recover the net difference between the energy amount billed to customers and the energy charge to LUI using the settlement invoice from the IESO. LUI 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 2012, LUI is requesting disposition of the December 31, 2010 audited balance, less the 2011 IRM approved disposition amounts plus the forecasted interest through April 30, 2012 for account 1588 - Power. The requested amount is a credit of $ -$ 411,307 |.

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 LUI using the settlement invoice from the IESO. LUI 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 2012, LUI is requesting disposition of the December 31, 2010 audited balance, less the 2011 IRM approved disposition amounts plus the forecasted interest through April 30, 2012 for account 1588 sub account Global Adjustment through a separate non-RPP rate rider. The requested amount is a credit of $ -$ 115,424 |.

1590 Recovery of Regulatory Asset Balances

This account includes the regulatory asset or liability balances authorized by the Board for recovery in rates or payments/credits made to LUI's customers. In accordance with the Board's Decision and Order for LUI's 2008 Cost of Service this Regulatory Asset rate rider is no longer included in the Distribution Rates. Separate sub-accounts are maintained for expenses, interest, and recovery amounts. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2012, LUI is requesting disposition of the December 31, 2010 audited balance, less the 2011 IRM approved disposition amounts plus the forecasted interest through April 30, 2012 for account 1590. The requested amount is a debit of $ $ 292

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 approved by the Board in LUI's 2011 IRM (EB-2010-0095). The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

In accordance with the OEB 2010-0095 Decision and Order for LUI's 2011 IRM rate approval, the December 31, 2009 balances and projected interest to April 30, 2011 totaling $ 444,911 were transferred to account 1595 in April, 2011. LUI is requesting a disposition of both credit balances in this account, relating to 2008 and

2009 balances of $ -$ 70 and $ -$ 229,688 respectively.

GROUP 2 ACCOUNTS

1508 Other Regulatory Assets – Late Payment Penalties

This account is used to record the transactions for the Late Payment Penalty payment associated with OEB EB-2010-0295. The Board ordered that the costs and damages arising from the settlement of the LPP class action should be allocated to all customers on the basis of distribution revenues. The associated revenues from rate riders associated with this are included. LUI uses the accrual method. The Board prescribed interest rates are used to calculate carrying charges and the interest is recorded in a sub-account.

For 2012, LUI is not yet requesting disposition of the balances in this account.

1508 Other Regulatory Assets – Other

This account includes the amounts of regulatory-created assets, not included in other accounts, resulting from the ratemaking actions of the Board. Specifically, this account includes amounts paid to Hydro One for regulatory assets. 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 Incremental Capital Charges

This account is used to record the amount charged by Hydro One Networks Inc., based on the settlement invoice for Incremental Capital Charges. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a

sub-account.

For 2012, LUI is requesting disposition of the December 31, 2010 audited balance plus the forecasted interest through April 30, 2012 for account 1508 – Sub-account Incremental Capital Charges. The requested amount is a debit of $ **9,421** .

1518 Retail Cost Variance Account - Retail

This account includes the amounts of net revenues derived from the services related to establishing Service Agreements, Distributor-Consolidated Billing, Retailer-Consolidated Billing and Split Billing, as well as the costs of entering into Service Agreements and related to contract administration, monitoring, and other expenses necessary to maintain the contract, as well as the incremental costs incurred to provide the services above.

The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2012, LUI is requesting disposition of the December 31, 2010 audited balance plus the forecasted interest through April 30, 2012 for account 1518 of $ **45,145**

1548 Retail Cost Variance Account – STR

This account includes revenues derived from the Service Transaction Request services described in the 2000 Electricity Distribution Rate Handbook and charged by the distributor, as prescribed, in the form of a Request fee, Processing fee, Information Request fee, Default fee and Other Associated Costs fee as well as the incremental cost of labour, internal information system maintenance costs, and delivery costs related to the provision of the services associated with the above items.

The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2012, LUI is requesting disposition of the December 31, 2010 audited balance plus the forecasted interest through April 30, 2012 for account 1548 of $ $ 41,118

1521 Special Purpose Charge (SPC) Assessment Variance Account

This account includes the amount remitted to the Minister of Finance for the SPC assessment. Separate sub-accounts are maintained to record amounts recovered from customers over a one-year period commencing on the date that recovery amounts are billed to customers. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account. The April 23, 2011 letter from the Board stated that requests for disposition of the balances will be addressed as part of the proceedings to set rates for the 2011 rate year, no later than April 15, 2012.

LUI established account 1521 Sub-account 2011 SPC Variance, and Sub-account 2011 SPC Assessment Carrying Charges in accordance with the Board's April 23, 2011 letter. LUI's share of the Assessment for MEI Conservation and Renewable program of $106,153 was recognized in this account in July 2010, and customer billing for recoveries commenced May 1, 2010. As per the Board's instructions, LUI will recover the SPC assessment over a one-year period and apply to the Board no later than April 15, 2012 for an order to clear any debit or credit balance remaining in these 1521 Sub-Accounts.

1525 Miscellaneous Deferred Debits

This account includes debits not elsewhere provided for which will benefit future periods and shall be carried forward and charged to expense over the term of the benefit. Currently this account contains the amounts related to the Late Payment Penalty $36,872.16. This amount was appropriate reallocated to the proper account 1508 subaccount, Late Payment Penalties, on January 1, 2011. LUI has discontinued use of this account. However, while in use, the Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

1555 Smart Meter Capital and Recovery Offset Variance

This account records the net of the amounts paid for direct capital costs related to the smart meter program and the amounts charged to customers using the OEB- approved smart meter rate adder. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

LUI is following the Smart Meter Funding and Cost Recovery Guideline dated October 22, 2008 (G-2008-0002) and is requesting a rate rider to recover the True-Up Revenue Requirement from 2008 – 2011 inclusive. This is outlined in more detail later in this Exhibit.

LUI is requesting a specific rate rider for the disposition of the December 31, 2010 audited balance plus the forecasted interest through April 30, 2012 for the Stranded Meters. The requested amount related solely to Stranded Meters is $ $ 279,651 .

1556 Smart Meter OM&A Variance

This account records the incremental operating, maintenance, amortization and administrative expenses directly related to smart meters. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account. LUI is following the Smart Meter Funding and Cost Recovery Guideline dated October 22, 2008 (G-2008-0002) and is not requesting recovery of the December 31, 2010 audited balance for account 1556 – Smart Meter OM&A

1562 Deferred Payments in Lieu of Taxes & 1563 Contra

This account records the amount resulting from the OEB-approved PILs methodology for determining the 2001 deferral account allowance and the PILs proxy amount determined for 2002 and subsequent periods ending April 30, 2007.

LUI is requesting recovery of the December 31, 2010 audited balance credit of $ -$ 97,487 and is currently undergoing the review of this account to present to the Board for disposition. In order to not delay any further the filing of Lakefront's 2012 cost of service rate application, Lakefront has filed an application that fulfills the filing requirements except for the completion of evidence to support the disposition of account 1562. The evidence to support the disposition of account 1562 will be filed by November 30, 2011.

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. LUI 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.

LUI is requesting disposition of the December 31, 2010 audited balance plus the forecasted interest through April 30, 2012 for account 1582. The requested amount is a debit of $ **18,587** .

AMENDMENT TO 2011 IRM DEFERRAL/VARIANCE ACCOUNT DISPOSITION (2011) RATE RIDER

2011 IRM Approval and Board Directive

On March 17, 2011 the Ontario Energy Board's Decision and Order EB-2010-0095 approved four-year disposition for LUI's Group 1 deferral and asset balances in the amount of $ 444,911 (DR), which includes a credit balance of $ 50,423 in the 1588 global adjustment sub-account.

In 2011, the approved balances were transferred to account 1595. Table 9-1 below summarizes the 2011 approved Group 1 accounts and amounts for disposition.

Table 9-2 2011 IRM Approved Group 1 Amounts for Disposition

Account Description	Account Number	Principal Amounts A	Interest Amounts B	Total Claim C = A + B
LV Variance Account	1550	136,059	(1,804)	134,255
RSVA - Wholesale Market Service Charge	1580	57,776	10,305	68,081
RSVA - Retail Transmission Network Charge	1584	(3,215)	333	(2,882)
RSVA - Retail Transmission Connection Charge	1586	(10,891)	(48)	(10,939)
RSVA - Power (Excluding Global Adjustment)	1588	(523,460)	(27,266)	(550,726)
RSVA - Power (Global Adjustment Sub-account)	1588	(47,668)	(2,755)	(50,423)
Recovery of Regulatory Asset Balances	1590	0	0	0
Balance of Disposition and recovery of Regulatory Balances Account (2008)	1595	(28,675)	(3,603)	(32,278)
Disposition and recovery of Regulatory Balances Account	1595	420,074	24,838	444,911
	Total	0	0	0

Re-Allocation of 2011 IRM3 DefVar Balances to Proposed Rate Classes

In accordance with the instructions in the OEB 2011 IRM3 DefVar model, Group 1 balances as at December 31, 2009 were allocated to each rate class using the same kWh based percentages in the 2008 Cost of Service Model.

DEFERRAL AND VARIANCE ACCOUNTS REQUESTED

LUI is requesting the following new or continuation of existing deferral or variance accounts:

- Continuation of the IFRS Transition Costs account;
- Two new deferral accounts for Smart Meters Rate Rider;
  - to determine the difference between original smart meter rate adders and the revenue requirement as calculated in Exhibit 9, Smart Meter rate rider model;
  - to recover stranded meter costs, in a separate sub account.

CONTINUATION OF IFRS TRANSITION COST SUB – ACCOUNT 1508

In 2010, the OEB approved sub-account 1508 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.

As a qualifying entity, LUI will be in a position to implement IFRS on January 1, 2011 pending future decisions and direction from the IASB, the AcSB, and the OEB. LUI therefore requests the continuation of the IFRS Transition Cost sub-account 1508 until April 30, 2012.

METHODS OF DISPOSITION OF ACCOUNTS AND BILL IMPACTS

ALLOCATORS

LUI submits the following Allocators in Table 9-13 used to assign the Group 1 and Group 2 balances to rate each class.

Table 9-3 Allocators

2012 Data By Class	kW	kWhs	Non RPP KwH	Cust/Conn. Num.'s	1595 ALLOCATOR	Dx Revenue
RESIDENTIAL CLASS		73,125,152	8,441,723	8,603	115,925.37	$ 2,492,376
GENERAL SERVICE <50 KW CLASS		35,160,634	4,169,928	1,102	55,421.82	$ 668,393
GENERAL SERVICE > 50 - 2999 KW	303,629	120,608,902	107,789,256	127	184,520.27	$ 1,205,883
GENERAL SERVICE > 3000 - 4999 KW	47,442	19,295,356	19,295,356	1	35,196.19	$ 64,222
UNMETERED SCATTERED LOADS		716,623	714,574	77	1,097.68	$ 51,186
SENTINEL LIGHTS	218	78,431	78,430	54	67.58	$ 5,195
STREET LIGHTING	3,343	1,215,575	1,215,575	2,804	2,259.58	$ 238,631
Totals	354,633	250,200,674	141,704,842	12,767	394,488.49	$ 4,725,887
						$ -

Allocators	kW	kWhs	Non RPP KwH	Cust. Num.'s	1595 ALLOCATOR	Dx Revenue
RESIDENTIAL CLASS	0.0%	29.2%	6.0%	67.4%	29.4%	52.7%
GENERAL SERVICE <50 KW CLASS	0.0%	14.1%	2.9%	8.6%	14.0%	14.1%
GENERAL SERVICE >50 KW	85.6%	48.2%	76.1%	1.0%	46.8%	25.5%
GENERAL SERVICE > 3000 - 4999 KW	13.4%	7.7%	13.6%	0.0%	8.9%	1.4%
UNMETERED & SCATTERED LOADS	0.0%	0.3%	0.5%	0.6%	0.3%	1.1%
SENTINEL LIGHTS	0.1%	0.0%	0.1%	0.4%	0.0%	0.1%
STREET LIGHTING	0.9%	0.5%	0.9%	22.0%	0.6%	5.0%
Totals	100%	100%	100%	100%	100%	100%

Table 9-4 Group 1 Balances for disposition

Deferral and Variance Accounts:	Amount	ALLOCATOR	Residential	GS < 50 KW	GS 50 - 2999 kW	GS 3,000 - 4,999	USL	Sentinel Lighting	Streetlight	Total	
1550	$ (101,408)	kWh	(29,638)	(14,251)	(48,884)	(7,821)	(290)	(32)	(493)	(101,408)	$ -
1580	$ (263,623)	kWh	(77,048)	(37,047)	(127,079)	(20,330)	(755)	(83)	(1,281)	(263,623)	$ -
1584	$ 26,403	kWh	7,717	3,710	12,728	2,036	76	8	128	26,403	$ -
1586	$ 31,723	kWh	9,271	4,458	15,292	2,446	91	10	154	31,723	$ -
1588 Excl GA	$ (411,307)	kWh	(120,211)	(57,801)	(198,270)	(31,720)	(1,178)	(129)	(1,998)	(411,307)	$ -
1588 - Global Adjustment	$ (115,424)	kwh - Non RPP	(6,876)	(3,397)	(87,798)	(15,717)	(582)	(64)	(990)	(115,424)	$ -
1590	$ 292	kWh	85	41	141	23	1	0	1	292	$ -
1595- 2008	$ (70)	Proportion to Disposition	(20)	(10)	(33)	(6)	(0)	(0)	(0)	(70)	$ -
			-	-	-	-	-	-	-	-	$ -
Subtotal - RSVA	$ (833,414)	$ -	$ (216,720)	$ (104,295)	$ (433,903)	$ (71,089)	$ (2,639)	$ (289)	$ (4,478)	$ (833,414)	$ -

Table 9-5 Group 2 Balances for disposition

1508	$ 9,421	Dx Revenue	5,068	1,438	2,342	122	87	10	354	9,421	
1518	$ 45,145	# of Customers	30,421	3,896	449	4	271	190	9,914	45,145	
1548	$ 41,118	# of Customers	27,707	3,549	409	3	247	173	9,029	41,118	
1582	$ 18,587	kWh	$ 5,432	$ 2,612	$ 8,960	$ 1,433	$ 53	$ 6	$ 90	$ 18,587	
1562		Case by Case Basis									
Subtotal - Non RSVA, Variable	$ 114,271		$ 68,629	$ 11,495	$ 12,160	$ 1,562	$ 659	$ 379	$ 19,388	$ 114,271	
Total to be Recovered	$ (719,142)		$ (148,092)	$ (92,801)	$ (421,743)	$ (69,527)	$ (1,979)	$ 90	$ 14,909	$ (719,142)	

Table 9-6 RSVA Power Sub-Account Global Adjustment

		Residential	GS < 50 KW	GS 50 - 2999 kW	GS 3,000 - 4,999	USL	Sentinel Lighting	Streetlight
Global Adjustment Balance to be collected or refunded	$ (115,424)	$ (6,876)	$ (3,397)	$ (87,798)	$ (15,717)	$ (582)	$ (64)	$ (990)
Number of years for Variable	4							
Balance to be collected or refunded per year, Variable	$ (28,856)	$ (1,719)	$ (849)	$ (21,950)	$ (3,929)	$ (146)	$ (16)	$ (248)

Table 9-7 Calculation of Rate Riders

Class	Residential	GS < 50 KW	GS 50 - 2999 kW	GS 3,000 - 4,999	USL	Sentinel Lighting	Streetlight
Deferral and Variance Account Rate Riders, Variable (Excluding Global Adjustment)	$ (0.0005)	$ (0.0006)	$ (0.2750)	$ (0.2836)	$ (0.0005)	$ 0.1763	$ 1.1889
Billing Determinants	kWh	kWh	kW	kW	kWh	kW	kW

	Residential	GS < 50 KW	GS 50 - 2999 kW	GS 3,000 - 4,999	USL	Sentinel Lighting	Streetlight
Global Adjustment Rate Rider	$ (0.0002)	$ (0.0002)	$ (0.0723)	$ (0.0828)	$ (0.0002)	$ (0.0733)	$ (0.0740)
Billing Determinants	kWh	kWh	kW	kW	kWh	kW	kW

Table 9-14, 9-15, 9-16 summarizes the variables used to determine the proposed regulatory asset, and Table 9-17 above summarizes the 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 2012 Test Year forecast load data and calculated for a one-year disposition period. The lower table summarizes the RPP Rate rider, for the 1588 sub account Global Adjustment.

Proposed Rates and Bill Impacts

The bill impacts are shown in Exhibit 8.

SMART METER PROPOSAL

In this application Lakefront Utilities Inc. is applying for the disposition of smart meter costs related to smart metering in its service area to its current smart meter funding adder to be effective May 1 2012.

LUI is specifically requesting the following:

- An actual cost recovery rate rider of $ $ 0.05 per metered customer per month for the period May 1, 2012 to April 30, 2013. This rate rider will collect the difference between the smart meter adder collected from May 1, 2006 to April 30, 2012 and the 2010 and 2011 revenue requirement related to smart meters deployed as of December 31, 2010. Approval to include smart meter capital deployed as of December 31, 2010, plus forecasted in 2011, in the 2012 rate base that supports the 2012 revenue requirement and distribution rates which is the subject of this rate application.

- Approval to include smart meter operation and maintenance expenses in the 2012 revenue requirement associated with smart meters deployed as of January 1, 2011.

- Approval to implement a rate rider of $ 2.37 over a one year period, in order to recover the costs associated with Stranded Meters, as of December 31, 2010. In doing so, LUI is removing the NBV of the Stranded Meters from Rate Base, effective January 2012.

Table 9-8

2011 Approved Smart Meter Rate Adder	$	2.50
2012 Proposed Smart Meter Rate Rider	$	0.05
Variance	$	2.45

Customer bill impacts arising from these requests are an overall decrease of $ 2.45 per metered customer per month for smart meter funding adder/rider, offset by the stranded meter rider of $ 2.37.

Smart Meter Program Status

LUI began recovery of smart meter funding adders since 2006:

- In the **2006** Decision and Order (EB-2005-0436) in accordance to the Generic Decision which provided $0.30 per month, per residential customer, to be added to LUI's revenue requirement. A monthly fixed charge of $0.26 metered customer per month effective May 1, 2006, was billed and the proceeds were credited in OEB Account 1555, Smart Meter Capital and Recovery Offset Variance Account.

- In the **2007** Decision and Order (EB-2007-0550), LUI received approval to continue the $0.26 per metered customer per month smart metering funding charge for the 2007 IRM rate year.

- In the **2008** Decision and Order (EB-2007-0761), LUI received approval to set a revised smart meter rate adder of $1.00 per metered customer per month.

- In the **2009** Decision and Order (EB-2008-0193), LUI received approval to continue the smart meter funding adder of $1.00 per metered customer per month previously approved by the Board.

- In its **2010** IRM Decision and Order (EB-2009-0233), LUI received approval for the smart meter funding adder of $2.00 per metered customer per month.

- In its **2011** IRM Decision and Order (EB-2010-0095), LUI received approval from the Board for a smart meter funding adder of $2.50.

LUI installed 8,818 smart meters by end of 2010. In this application, LUI seeks recovery of the revenue requirement in respect of these smart meters. As at December 31, 2010, LUI Smart Meter Implementation program was approximately 98 % complete. LUI implemented TOU

billing effective June 1, 2011. Projected 2011 costs in this application are for Billing/Customer Service software and costs related to bill presentment, bill print modification, and MDMR integration costs, etc. The total capital cost for the smart meter implementation as of June 2011 is approximately $ $ 1,945,885 as reflected in Exhibit 9, Table 9-9.

Smart Meter Initiative (SMI)

In preparation for the Smart Meter Initiative based on a Directive in June 2004 by the Minister of Energy under Section 27.1 of the *Ontario Energy Board Act*, 1988, Lakefront Utilities and 49 other utilities in the Province formed an Ontario Utilities Smart Meter (OUSM) working group, led by a consulting firm by the name of Util-Assist Inc. Through the OUSM group, much information regarding AMI technologies was gathered and analyzed and detailed reports were made available to members which provides test results and detailed information regarding functionality.

Util-Assist – Consulting Assistance

In the middle of 2007, in seeking economies of scale for a cost-effective deployment and always considering ways of reducing costs, LUI and other utilities that form the **Cornerstone Hydro Electric Concept (CHEC)** group, engaged in a collaborative initiative of entering into a professional services agreement with Util-Assist, an Ontario consulting firm specializing in metering solutions and technologies. Util-Assist was hired to assist with the development of the project plan, evaluations, award of contract, project monitoring, problem solving and reporting. Various preliminary project activities were undertaken and most importantly, the processing of Requests for Proposal for mass installation of smart meters, the selection, supply and support of an installer and a meter-data

operational data store (ODS), were issued and evaluated culminating in the selection of successful vendors. Util-Assist remained actively involved in the implementation and rollout phases of the mass deployment contract and ODS contract negotiation through to Q2 2010.

Util-Assist's services to LUI were expanded in 2010 to include project management assistance and training services related to our internal operations and readiness for MDMR enrolment.

The Util-Assist Report, filed under separate cover provides the major overview of the project and specific information associated with LUI.

Cornerstone Hydro Electric Concepts Association (CHEC)

Cornerstone Hydro Electric Concepts Association Inc. (CHEC), is a not-for-profit member owned organization that provides value added services to their Local Distribution Companies (LDC) members. CHEC strives to reduce LDC costs through sharing of knowledge and information as well as providing savings through joint purchasing of goods and services with its members.

The twelve LDCs which form CHEC represent a customer base of approximately 100,000 customers. The existing members in CHEC include the following LDCs:

- Centre Wellington Hydro
- COLLUS Power
- Innisfil Hydro
- Lakefront Utilities
- Lakeland Power Distribution
- Midland Power Utility
- Orangeville Hydro
- Parry Sound Power

- Rideau St. Lawrence Distribution
- Wasaga Distribution
- Wellington North Power
- West Coast Huron Energy.

Cornerstone Hydro Electric Concepts Association (CHEC) is an incorporated body that is governed by a Board of Directors. The Board of Directors and Executive are voluntary positions from staff of the member Local Distribution Companies (collectively, "LDCs" or "Member LDC's").

CHEC's vision is "to be recognized as the premier LDC Cooperative in the province, by meeting or exceeding member expectations through the sharing of services, opportunities, knowledge and resources." CHEC is built on sharing between LDCs through committees, staff and consultant positions, shared documents, specific working groups, combined projects and informal communications between members and staff.

AMI Selection Process - Procurement of Smart Meters and Installation Services

LUI was an active participant in the London Phase Two AMI RFP process and details of our participation with the CHEC group is summarized in the Util-Assist report dated August 15, 2011 filed under separate cover.

Lakefront Utilities was awarded **Sensus' FlexNet™ AMI** system as the preferred vendor by the Fairness Commissioner (refer to the Attestation Letter of the Fairness Commissioner attached as Appendix A).

Following the selection of an AMI provider, attention was turned to the selection of an Installer and an ODS

Vendor and details of LUI's participation with the CHEC group is summarized in the Util-Assist report filed under separate cover on pages 8 and 9 consecutively.

Residential and Commercial Deployment of Sensus Smart Meters

LUI researched the effort required and costs associated with the mass deployment and quickly concluded that the most cost-effective approach to converting the conventional meters to smart meters was to utilize a third-party contractor. Olameter received the contract to perform the mass installation as a result of the CHEC RFP process, and the installations got underway in August 2009 with a scheduled completion date of June 2010. By June 2010, with close to 8,000 residential and GS<50 meters installed, the project was essentially 85% complete. Delays were related to the fact that LUI has a higher percentage of inside meters than normal. However, by December 31, 2010, the remaining meter installations related to access issues, unsafe conditions, and structural changes required to get the smart meters in, were completed and LUI was essentially 98% complete. All installations were effectively completed by July 2011.

Annual Security Audit

With the mass deployment of AMI systems, security of the AMI network is critical to prevent utilities from becoming susceptible to new levels of potential security breaches and to ensure

customer privacy and acceptance of the network. By installing network infrastructure in the field, there is now a requirement for additional security measures in order to ensure that utility data and equipment are kept secure from manipulation or other forms of control. As networks are deployed throughout the world, cyber security articles and reports with reports of the potential for smart-grid hacking are becoming commonplace in the media. The minimum Functional Specification for an Advanced Metering Infrastructure (AMI) released in July 2006 identified the need for security within the AMI network – Section 2.11 Security and Authentication: "The AMI shall have security features to prevent unauthorized access to the AMI and meter data and to ensure authentication to all AMI elements." Some of the privacy and network security infrastructure concerns that have been raised include:

- Monitoring a consumer's usage;
- Modifying one's own, or another consumer's usage;
- Interrupting the power of one or more consumers; and
- Tampering with demand side management tools which can be controlled through smart meters.

Since early 2009, Ontario utilities have been working with their smart meter providers to understand the security features of the networks, best practices for their deployment and new features that are being developed for future implementation within the smart meter networks. In November 2009 the Information and Privacy Commissioner of Ontario released the report Smart Privacy for the Smart Grid which identified areas of concern to be addressed in the area of smart meter and smart grid devices.

Going forward, LUI has budgeted for an annual security audit, as this is a prudent approach to satisfying the due diligence requirements for protection not only of the customer information,

but also to ensure that access to the infrastructure is properly protected, thereby securing against unwanted modifications to data collection and/or load-control functionality. Security of the network and ensuring that customer data is protected at all times has resulted in the development of governance standards requiring extensive security measures such as NERC (North American Electric Reliability Corporation). The NERC reliability standards are developed by the electricity industry using a balanced, open, fair and inclusive process managed by the NERC Standards Committee.

For many Ontario LDCs, including LUI, completing a security audit at a NERC, NIST (Network Information Security & Technology) or comparable level would be a cost-prohibitive exercise. Therefore, LUI joined a consortium of Ontario Util-Assist LDC customers in the issuance of the November 2010 "Smart Meter Network Security Audit Services" Request for Proposal.

The objective of the RFP is to select an audit partner who would complete a security audit of the Sensus AMI systems for consortium members with Sensus technology in place, and to the work with Sensus towards the implementation of viable countermeasures to resolve all security concerns. The selected audit firm will first complete an in-depth security review at one participating utility that has the Sensus solution. Once this review is complete, the audit firm would then review the technology at all remaining participating utilities to confirm that their Sensus AMI systems are configured to the same standard as that declared as the standard for the group audit. Audits are anticipated to include end-to end from the meter to utility systems and home area network.

Operational Data Store (ODS)

As LUI moved into the implementation of its AMI systems, a need was recognized for an application that supported full integration with the MDM/R and enabled our team to

audit, validate, interact with and gain valuable business information from the wealth of meter data that was being collected. The AMI system, while fully capable of collecting meter read data and forwarding that raw data to the MDM/R, does not provide all of the functionality necessary to interpret and/or leverage the information it is providing in an educated and meaningful fashion.

LUI, with Util-Assist's support, issued an RFP for an operational data store (ODS) in Q4 2008. Following the RFP process, shortlisted vendors delivered software demonstrations, leading to the selection of Kinetiq as the preferred vendor with their ODS application.

The primary requirements and features of the operational data store (ODS) are:

a) **Dashboard of Field Issues Possibly Requiring Intervention** - Dashboard visibility to the real-time performance of the smart meter system to provide field staff with visibility to troubleshooting priorities such as non-communicating meters, non-communicating tower gateways/collectors, etc.
b) **AMI SLA Audit** - Audit and reporting / real-time notification capabilities to monitor AMI performance and therefore ensure that data collection and submission service-level agreements (SLAs) with the centralized MDM/R are consistently met.
c) **Read Re-submission** - The ODS will provide a data repository to facilitate backfilling reads after a meter installation, front-filling reads after a meter removal, and replacing reads labeled as NVE (Needs Verification or Edit) by the IESO MDM/R system. The ODS will provide a mechanism for meter data editing and VEE (Validation, Estimation and Editing) processes (in keeping with the MDM/R specifications), such data can then be re-submitted to the MDM/R. Features such as "register read validation failure resolution" will be invaluable to LUI.

d) **IESO MDM/R Report Integration / Issue Resolution Automation** - The MDM/R produces a large volume of reports on a daily or regular basis each potentially containing large amounts of information. Kinetiq will load the MDM/R reports, and filter the information they provide in order to provide manageable, meaningful action items that can be prioritized, investigated and resolved.

e) **Meter Event Monitoring** - Dashboard visibility to report meter events and indicators such as outages, restorations, tampers, voltage changes, etc., many of which will afford LUI the opportunity to improve the safety and reliability of the distribution system.

f) **Revenue Protection** – LUI will be able to identify and respond to meter tampers which historically would have resulted in unidentified theft of power.

g) **Outage Reporting** - Real-time outage information to facilitate faster response time, and therefore improved system reliability.

Business Process Redesign

Throughout the latter half of 2010, the Util-Assist training team delivered a series of education sessions covering the MDM/R design specifications, meter read data, VEE and other billing processes, and the design of a testing/cutover strategy. LDCs have widely recognized that a number of business processes, including new account setup, meter installations, meter changes, move-in/move-out and final billing all require scrutiny and procedural modifications to ensure that MDM/R integrations are optimized. LUI personnel also attended IESO-led training on business process redesign in 2010. Actual business process redesign consultations were well underway at LUI in early 2011 and is an ongoing process leading up to and after cutover.

System Changes

LUI uses the Harris Northstar Billing System, which is used by several Ontario LDCs including some who had already completed their smart meter deployment and implemented TOU billing. LUI therefore expected the Northstar system to be fully capable of supporting MDM/R integration and TOU billing within defined regulatory timelines and negotiated to purchase the necessary add-on software modules and professional services to ensure that this occured before we initiated TOU billings.

Integration with MDM/R

By late 2009, internal LUI staff had begun attending relevant IESO training sessions regarding LUI's integration to the provincial Meter Data Management Repository (MDM/R) and we remained active and involved participants, attending the majority of IESO-hosted sessions on a variety of topics pertaining to the MDM/R.

LUI filed its registration paperwork and integration project plan with the IESO in Q1 2010. AS2 connectivity software to facilitate date integration with the MDM/R was selected and installed in May 2010 and connectivity testing was scheduled with the IESO for July 2010. The project plan called for Unit Testing to be executed in September 2010 but due to some delays, was completed in January 2011, and System Integration (SIT) and Qualification Testing (QT) in February 2011, in preparation for cutover to live data transfer with the MDMR by March 2011. With many technical steps and challenges overcome, LUI's ability to meet these targeted timelines was to a large extent contingent upon various software systems delivering the promised functionality and suppliers meeting their contractual obligations. LUI attain cutover to production in March 2011.

Transition to TOU Pricing

In mid-2010, the Ontario Government articulated an expectation that 1 million RPP customers would be billed using TOU pricing by the Summer of 2011, rising to 3.6 million customers by June 2012. On June 24, 2011, the Ontario Energy Board issued a proposed determination regarding mandated time-of-use pricing for regulated price plan customers (Board File No. EB-2011-0218), suggesting that distributor-specific TOU dates would be the most appropriate approach, as it allows for the deadline to logically follow MDM/R enrolment activities.

According to the proposal, LUI's mandatory TOU date would be the first day of the first billing period that commences 9 months from the date identified in our baseline plan for the commencement of meter enrolment. In response to the Board's issuance of the June 24 correspondence, LUI subsequently updated our Baseline filing to ensure that it reflected the MDM/R enrolment date of November 2010

LUI is proud that it completed the transition to TOU pricing prior to target date of September 2011.

Web Presentment

The Ministry of Energy and Infrastructure has indicated that electricity customers should ideally have web access to their consumption data with which to make informed decisions about future usage as part of a utility's rollout of TOU pricing. Accordingly, the SME Transition Committee formally requested a proposal from an established web presentment service provider, Whitecap Canada Inc., as they are already providing an effective solution to several LDCs in Ontario. LUI identified the security features, ease of implementation, ease of use, existing integration with the provincial MDM/R, low cost-

per-customer advantages, and the consistent user experience for customers as they relocate within Ontario as key benefits of the Whitecap portal solution. LUI will continue exploring its options relating to Web Presentment and anticipates implementing a solution in 2012 once the TOU billing monitoring of any possible challenge is complete and reliable data (current and to some extent historical) is readily available for our customers.

Consumer Education Plan

LUI leveraged the significant development efforts undertaken by the Ministry of Energy to support LDC-specific communications tools and resources related to Time-of-Use (TOU) roll-out to electricity customers. In keeping with our mission statement to deliver exceptional customer service to the ratepayers in our service territory, LUI planned an extensive customer education and outreach campaign aligned with our time-of-use (TOU) pricing rollout. In the meantime, we continue to keep customers informed about our TOU pricing and CDM initiatives through our corporate website, and through regular mail outs in LUI's customer bills.

Procurement of Smart Meters Agreements

The following agreements are being filed with the Board Secretary on a confidential basis:

- Advanced Metering Infrastructure Services Agreement between LUI and Sensus Inc.;
- Smart Meter Installation Agreement between LUI and Olameter Inc; and
- Operational Data Store Agreement between LUI and Kinetiq Inc.; and
- Util-Assist Report;.

Sensus Inc., Olameter Inc. and Kinetiq Inc. are corporations which are engaged in competitive businesses. The disclosure of the terms of these agreements could reasonably be expected to prejudice the economic interests, competitive positions and cause undue financial interests of Sensus Inc., Kinetiq and Olameter respectively, since it would enable their competitors to ascertain the scope and pricing of services provided by these companies. The Board's Practice Direction on Confidential Filings (the "Practice Direction") recognizes that these are among the factors that the Board will take into consideration when addressing the confidentiality of filings. They are also addressed in section 17(1) of the Freedom of Information and Protection of Privacy Act ("FIPPA"), and the Practice Direction notes (at Appendix C of the Practice Direction) that third party information as described in subsection 17(1) of FIPPA is among the types of information previously assessed or maintained by the Board as confidential. Accordingly, LUI requests that these Agreements be kept confidential.

LUI is prepared to provide copies of the Agreements to parties' counsel and experts or consultants provided that they have executed the Board's form of Declaration and Undertaking with respect to confidentiality and that they comply with the practice direction, subject to LUI's right to object to the Board's acceptance of a declaration and undertaking from any person. In keeping with the requirements of the practice direction, LUI is filing confidential unredacted versions of the Agreements under separate cover, in a sealed envelope marked "Confidential".

Capital Cost Analysis

LUI had forecasted to have a total of 8818 smart meter installed by December 31, 2010. Due to new developments, residential customer changes and business closures in our

service territory, the number of residential meters installed to date are 8,465 with 2 installations remaining, and 1,038 General Service <50, with 31 installations remaining.

Advanced Metering Communication Device (AMCD) costs were higher than expected by $93K due to LUI's service territory geography and a second AMCD requirement to facilitate Colborne customers.

The costs for Advanced Metering Regional Collector (AMRC) were more than planned in the budget, as the original RFP that was submitted on behalf of LUI, requested only one collector; however LUI required 2 collectors, one for Cobourg and one for Colbourne. The cost of the additional collector was also negatively impacted by foreign exchange currency.

The majority of computer software costs for Advanced Metering Control Computer (AMCC) initially expected to be incurred in 2010 in the amount of $25K, was not required.

AMI costs related to minimum functionality were higher by $9K, which is not material for this Application.

OM&A Cost Analysis

Actual OM&A costs for 2010 were $84K under forecast due to less than forecasted Tower Gateway Base Station (TGB) costs in the amount of $27K. Also, customer communication costs anticipated for 2010 were $22K, and no costs were incurred in 2009 or 2010. The forecasted other AMI expenses were anticipated to be $23K, however up until December 31, 2010, the total costs incurred were only $1K.

SMART METER RATE RIDER FOR COST RECOVERY

Smart Meter Costs

In this application, in addition to audited figures for recoveries up to December 31, 2010, Lakefront Utilities Inc. is also seeking recovery of costs related to the 685 smart meters installed in the Town of Cobourg and Village of Colborne service area in 2011.

In the OEB Combined Proceeding EB-2007-0063, to determine issues related to the recovery of costs incurred by distributors that are associated with activities, the Board discussed the issue of confidentially with respect to pricing information. The OEB determined that

"*… the competitive positions of the suppliers would be eroded if the prices charged… were disclosed. The Board accepts this position.",* and, that "*the Board finds that it is in the public interest that the prices charged to the applicants, including unit prices, installation costs, and the contractual terms, be kept confidential. However, the aggregated per unit installed prices will be part of the decisions".*

In keeping with that Decision, is being filed in confidence in its entirety, which includes confidential documents pertaining to cost and vendor information.

1 **Table 9-9 - Detail of Capital and OM&A Costs**

regardless of whether a distributor has deployments in 2012, distributors should enter the forecasted OM&A for 2012 for all smart meters in service.

Smart Meter Capital Cost and Operational Expense Data		2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast	Total
Smart Meter Installation Plan									
Actual/Planned number of Smart Meters installed during the Calendar Year									
Residential					5,884	2,364	217		8465
General Service < 50 kW						570	468		1038
Actual/Planned number of Smart Meters installed (Residential and GS < 50 kW only)		0	0	0	5884	2934	685	0	9503
Percentage of Residential and GS < 50 kW Smart Meter Installations Completed		0.00%	0.00%	0.00%	61.92%	92.79%	100.00%	0.00%	100.00%
Actual/Planned number of GS > 50 kW meters installed									0
Other (please identify)									0
Total Number of Smart Meters installed or planned to be installed		0	0	0	5884	2934	685	0	9503
1 Capital Costs									
1.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	**Asset Type** (Asset type must be selected to enable calculations)	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.1.1 Smart Meters *(may include new meters and modules, etc.)*	Smart Meter				793,778	292,469	175,448		$ 1,261,695
1.1.2 Installation Costs *(may include socket kits, labour, vehicle, benefits, etc.)*	Smart Meter				86,536	95,901	79,907		$ 262,344
1.1.3a Workforce Automation Hardware *(may include fieldwork handhelds, barcode hardware, etc.)*									$ -
1.1.3b Workforce Automation Software *(may include fieldwork handhelds, barcode hardware, etc.)*									$ -
Total Advanced Metering Communications Devices (AMCD)		$ -	$ -	$ -	$ 880,314	$ 388,370	$ 255,355	$ -	$ 1,524,039
1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)	**Asset Type**	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.2.1 Collectors	Smart Meter				298,140				$ 298,140
1.2.2 Repeaters *(may include radio licence, etc.)*									$ -
1.2.3 Installation *(may include meter seals and rings, collector computer hardware, etc.)*									$ -
Total Advanced Metering Regional Collector (AMRC) (Includes LAN)		$ -	$ -	$ -	$ 298,140	$ -	$ -	$ -	$ 298,140
1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)	**Asset Type**	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.3.1 Computer Hardware									$ -
1.3.2 Computer Software									$ -
1.3.3 Computer Software Licences & Installation (includes hardware and software) *(may include AS/400 disk space, backup and recovery computer, UPS, etc.)*									$ -
Total Advanced Metering Control Computer (AMCC)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1.4 WIDE AREA NETWORK (WAN)	**Asset Type**	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.4.1 Activiation Fees									$ -
Total Wide Area Network (WAN)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONALITY	**Asset Type**	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.5.1 Customer Equipment *(including repair of damaged equipment)*									$ -
1.5.2 AMI Interface to CIS									$ -
1.5.3 Professional Fees	Computer Software			20,974	30,616	18,994	8,546		$ 79,130
1.5.4 Integration									$ -
1.5.5 Program Management									$ -
1.5.6 Other AMI Capital	Computer Software				12,799	31,777			$ 44,576
Total Other AMI Capital Costs Related to Minimum Functionality		$ -	$ -	$ 20,974	$ 43,415	$ 50,771	$ 8,546	$ -	$ 123,706
Total Capital Costs Related to Minimum Functionality		$ -	$ -	$ 20,974	$ 1,221,869	$ 439,141	$ 263,901	$ -	$ 1,945,885
1.6 CAPITAL COSTS BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*	**Asset Type**	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06									$ -
1.6.2 Costs for deployment of smart meters to customers other than residential and small general service									$ -
1.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.									$ -
Total Capital Costs Beyond Minimum Functionality		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Smart Meter Capital Costs		$ -	$ -	$ 20,974	$ 1,221,869	$ 439,141	$ 263,901	$ -	$ 1,945,885

2 OM&A Expenses

2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
2.1.1 Maintenance *(may include meter reverification costs, etc.)*								$ -
2.1.2 Other *(please specify)*								$ -
Total Incremental AMCD OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)								
2.2.1 Maintenance								$ -
2.2.2 Other *(please specify)*								$ -
Total Incremental AMRC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)								
2.3.1 Hardware Maintenance *(may include server support, etc.)*								$ -
2.3.2 Software Maintenance *(may include maintenance support, etc.)*				14,927	42,874	52,904		$ 110,705
2.3.2 Other *(please specify)*								$ -
Total Incremental AMCC OM&A Costs	$ -	$ -	$ -	$ 14,927	$ 42,874	$ 52,904	$ -	$ 110,705
2.4 WIDE AREA NETWORK (WAN)								
2.4.1 WAN Maintenance								$ -
2.4.2 Other *(please specify)*								$ -
Total Incremental AMRC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY								
2.5.1 Business Process Redesign								$ -
2.5.2 Customer Communication (may include project communication, etc.)						10,444		$ 10,444
2.5.3 Program Management								$ -
2.5.4 Change Management (may include training, etc.)				6,184	10,963	18,960		$ 36,107
2.5.5 Administration Costs								$ -
2.5.6 Other AMI Expenses *(please specify)*				801	548			$ 1,349
Total Other AMI OM&A Costs Related to Minimum Functionality	$ -	$ -	$ -	$ 6,985	$ 11,511	$ 29,404	$ -	$ 47,900
TOTAL OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY	$ -	$ -	$ -	$ 21,912	$ 54,385	$ 82,308	$ -	$ 158,605
2.6 OM&A COSTS RELATED TO BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual		
2.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06								$ -
2.6.2 Costs for deployment of smart meters to customers other than residential and small general service								$ -
2.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.								$ -
Total OM&A Costs Beyond Minimum Functionality	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Smart Meter OM&A Costs	$ -	$ -	$ -	$ 21,912	$ 54,385	$ 82,308	$ -	$ 158,605

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Table 9-10 Summary of Forecast Smart Meter Costs & OM&A

3 Aggregate Smart Meter Costs by Category									
3.1	**Capital**								
3.1.1	Smart Meter	$ -	$ -	$ -	$ 1,178,454	$ 388,370	$ 255,355	$ -	$ 1,822,179
3.1.2	Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.3	Computer Software	$ -	$ -	$ 20,974	$ 43,415	$ 50,771	$ 8,546	$ -	$ 123,706
3.1.4	Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.5	Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.6	**Total Capital Costs**	**$ -**	**$ -**	**$ 20,974**	**$ 1,221,869**	**$ 439,141**	**$ 263,901**	**$ -**	**$ 1,945,885**
3.2	**OM&A Costs**								
3.2.1	**Total OM&A Costs**	**$ -**	**$ -**	**$ -**	**$ 21,912**	**$ 54,385**	**$ 82,308**	**$ -**	**$ 158,605**

Stranded Meter Costs

Lakefront Utilities is seeking disposition of its stranded meter costs. LUI requests Board approval for a stranded meter specific rate rider in the amount of $ $ 2.37 per metered customer per month for a one year period commencing May 1, 2012.

Table 9-11 Stranded Meters

Stranded Meters		
Capital Cost	$	688,736
Accumulated Depreciation	$	409,085
NBV	$	279,651
Rate Rider per Metered Customer per Month	$	2.37

The net book value of the stranded conventional meters at December 31, 2010 was $ 279,651.

Proceeds on the scrapped meters are captured in account 1555 as an offset to the costs in the deferral account, in accordance with the Board's Guideline 2008-0002 and the Board's January 16, 2007 letter to distributors on stranded meter costs related to the installation of smart meters.

A summary of LUI's actual and forecast smart meter costs aggregated in accordance with the OEB's category codes for smart meter costs is included in Table 9-20 above**.** The 2010 actual costs above are taken from LUI's financial records as at December 31, 2010. The December 31, 2010 balances in the smart meter deferral accounts have been audited by Collins Barrow, the external auditor.

Smart Meter Actual Cost Recovery Calculation

LUI has used a model provided by OEB staff and used by other distributors for smart meter actual cost recovery calculations. A copy of the Smart Meter Cost Recovery Model is provided in Appendix C.

The model calculates the revenue requirement amounts for purposes of the actual cost recovery to December 31, 2011. Table 9-22 summarizes the revenue requirement associated with these meters and the value of the smart meter funding adder collected over the period May 1, 2006 to December 31, 2011.

The 2011 costs included in this rate application are forecasted and not auditable until LUI's fiscal year end.

Table 9-12 Rate Rider to Recover Smart Meter Cost

	2006	2007	2008	2009	2010	2011	2012 and later	Total
Deferred and forecasted Smart Meter Incremental Revenue Requirement (from Sheet 5)	$ -	$ -	$ 1,147.24	$ 117,274.29	$ 274,832.34	$ 350,279.57	$ 278,712.28	$ 1,022,245.71
SMFA Revenues and carrying charges (from Sheet 8)	$ 16,231.29	$ 33,202.44	$ 52,116.45	$ 114,617.61	$ 174,162.78	$ 256,792.39	$ 90,513.00	$ 737,635.96
Net Deferred Revenue Requirement	-$ 16,231.29	-$ 33,202.44	-$ 50,969.21	$ 2,656.68	$ 100,669.56	$ 93,487.18	$ 188,199.28	$ 284,609.75
Number of Metered Customers (average for 2012 test year)	→	→	→	→	→	→	9833	

Calculation of Smart Meter Disposition Rider (per metered customer per month)

Years for collection or refunding	1	
Deferred Incremental Revenue Requirement from 2006 to December 31, 2011	$ 743,533.43	
SMFA Revenues collected from 2006 to 2012 test year (inclusive)	$ 737,635.96	
Net Deferred Revenue Requirement	$ 5,897.47	
SMDR May 1, 2012 to April 30, 2013	$ 0.05	Match
Check: Forecasted SMDR Revenues	$ 5,899.80	

Lakefront Utilities Inc. is seeking approval of the smart meter costs in this Application and of the transfer of the approved amounts from the smart meter deferral accounts to the appropriate fixed asset, revenue and expense accounts. As shown in Table 9-22**,** there is a difference of $ 5,897.47 between the revenue requirement related to the smart meter costs to December 31, 2011 and the corresponding smart meter adder collected from May 1, 2006 – April 30, 2012. LUI proposes to recover this amount from customer by a monthly rate rider of $ 0.05 per metered customer over the period May 1, 2012 to April 31, 2013.

Appendices:

Appendix A	Attestation Letter of the Fairness Commissioner
Appendix B	Auditor's Report
Appendix C	Smart Meter Cost Recovery Model

Appendix D Deferral and Variance Accounts

Conclusion

Lakefront Utilities Inc. respectfully submits that the costs necessary to fulfill its obligations under the provincially mandated Smart Meter initiative have been prudently incurred in accordance with Board guidelines; the proposed is just and reasonable, the associated customer bill impacts are minimal; and it is appropriate that the Board approve the proposed recovery rider at this time, for implementation effective May 1, 2012.

Appendix A

PRP International, Inc.
Fairness Advisory Services

August 1, 2008

Mr. Bruce Craig
President
Lakefront Utilities Inc.
207 Division Street, Box 577
Cobourg, ON K9A 4L3

Dear Mr. Craig:

Subject: Attestation of the Fairness Commissioner
Advanced Metering Infrastructure RFP, August-July 2008
London Hydro, Consortium & Add-On LDCs Smartmetering Project

PRP International, Inc. is pleased to submit its letter report of the Fairness Commissioner for the noted Request for Proposal (RFP) evaluation and selection phase. This judgment is being provided for the information and use of each Add-On LDC Sponsor, in their consideration of the report from the Evaluation Phase, for this competitive transaction.

"It is the judgment of PRP International, Inc., as the Fairness Commissioner, that the determinations of the two (2) highest ranked Proponents for the ***Lakefront Utilities Inc.*** *requirements are:*

- *KTI/Sensus Limited, as the recommended Preferred Proponent, based on its highest ranking, and*
- *Elster Metering and Silver Spring Networks were tied for the second ranked Proponent position*

These determinations were made in a fair (objective and competent) manner and consistent with the evaluation and selection processes set out in the RFP, issued August 14, 2007."

A detailed report for your records will be submitted to you, by August 31, 2008. Should you have any questions or require clarification of any matter contained in this letter report, please contact the undersigned.

Yours truly,

Peter Sorensen
President
cc: Mr. Gary Rains, RFP Project Director

203 - 8 QUEEN STREET, SUMMERSIDE, PE. C1N 0A6
TELEPHONE: 902.436.3930 FAX: 604-677-5409
EMAIL: fairness@telus.net

1 **Appendix B**

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LAKEFRONT UTILITIES INC.

NOTES TO THE FINANCIAL STATEMENTS
For the year ended December 31, 2010

5. DEFERRAL ACCOUNTS

As described in Note 2(b), the Company has recorded the following deferral accounts.

	2010 $	2009 $
Cost of power variance accounts	73,808	1,685,143
Retail settlement variance accounts	(236,498)	(787,281)
Smart Meters	1,365,795	1,044,727
Other deferral accounts	144,268	248,306
	1,347,373	2,190,895

The deferral accounts are accumulated as prescribed by regulatory policy and will be subject to review and disposition through future rate review processes, the timing of which have yet to be determined. It is fully expected that the approved disposition of any asset or liability accumulated at that time will be through the adjustment of future rates. The Company continually assesses the likelihood of the recovery of recoverable assets. If recovery is no longer considered probable, the amounts are charged to operations in the year the assessment is made.

During the year there were authorized expenditures on the Smart Meter program in the aggregate amount of $423,500 (2009 - $1,267,837), which have been partially funded and offset by approved interim rate recoveries in the amount of $184,055 (2009 - $218,210). In addition, included in capital assets is an amount of $317,000 (2009 - $217,000) for meters which have been replaced. These amounts have not yet been written down as it is anticipated that these amounts will be approved and recoverable in future rate setting processes.

In the absence of rate regulation supporting the accumulation of these amounts, the Company would capitalize the amounts as equipment and the current year net income would be reduced by $159,000 (2009 - $241,000) for additional amortization of approximately $59,000 (2009 - $24,000) and for the writedown of $100,000 (2009 - $217,000) for the meter assets no longer in service.

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Appendix C

Distributors must enter all incremental costs related to their smart meter program and all revenues recovered to date in the applicable tabs except for those costs (and associated revenues) for which the Board has approved on a final basis, i.e. capital costs have been included in rate base and OM&A costs in revenue requirement.

For 2012, distributors that have completed their deployments by the end of 2011 are not expected to enter any capital costs. However, for OM&A, regardless of whether a distributor has deployments in 2012, distributors should enter the forecasted OM&A for 2012 for all smart meters in service.

Smart Meter Capital Cost and Operational Expense Data		2006	2007	2008	2009	2010	2011	2012 and later	Total
		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
Smart Meter Installation Plan									
Actual/Planned number of Smart Meters installed during the Calendar Year									
Residential					5,884	2,364	217		8465
General Service < 50 kW						570	468		1038
Actual/Planned number of Smart Meters installed (Residential and GS < 50 kW only)		0	0	0	5884	2934	685	0	9503
Percentage of Residential and GS < 50 kW Smart Meter Installations Completed		0.00%	0.00%	0.00%	61.92%	92.79%	100.00%	0.00%	100.00%
Actual/Planned number of GS > 50 kW meters installed									0
Other (please identify)									0
Total Number of Smart Meters installed or planned to be installed		0	0	0	5884	2934	685	0	9503
1 Capital Costs									
1.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	**Asset Type** (Asset type must be selected to enable calculations)	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.1.1 Smart Meters *(may include new meters and modules, etc.)*	Smart Meter				793,778	292,469	175,448		$ 1,261,695
1.1.2 Installation Costs *(may include socket kits, labour, vehicle, benefits, etc.)*	Smart Meter				86,536	95,901	79,907		$ 262,344
1.1.3a Workforce Automation Hardware *(may include fieldwork handhelds, barcode hardware, etc.)*									$ -
1.1.3b Workforce Automation Software *(may include fieldwork handhelds, barcode hardware, etc.)*									$ -
Total Advanced Metering Communications Devices (AMCD)		$ -	$ -	$ -	$ 880,314	$ 388,370	$ 255,355	$ -	$ 1,524,039
1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)	**Asset Type**	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.2.1 Collectors	Smart Meter				298,140				$ 298,140
1.2.2 Repeaters *(may include radio licence, etc.)*									$ -
1.2.3 Installation *(may include meter seals and rings, collector computer hardware, etc.)*									$ -
Total Advanced Metering Regional Collector (AMRC) (Includes LAN)		$ -	$ -	$ -	$ 298,140	$ -	$ -	$ -	$ 298,140

	Asset Type								
1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.3.1 Computer Hardware									$ -
1.3.2 Computer Software									$ -
1.3.3 Computer Software Licences & Installation (includes hardware and software) *(may include AS/400 disk space, backup and recovery computer, UPS, etc.)*									$ -
Total Advanced Metering Control Computer (AMCC)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

	Asset Type								
1.4 WIDE AREA NETWORK (WAN)		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.4.1 Activiation Fees									$ -
Total Wide Area Network (WAN)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

	Asset Type								
1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONALITY		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.5.1 Customer Equipment *(including repair of damaged equipment)*									$ -
1.5.2 AMI Interface to CIS									$ -
1.5.3 Professional Fees	Computer Software			20,974	30,616	18,994	8,546		$ 79,130
1.5.4 Integration									$ -
1.5.5 Program Management									$ -
1.5.6 Other AMI Capital	Computer Software				12,799	31,777			$ 44,576
Total Other AMI Capital Costs Related to Minimum Functionality		$ -	$ -	$ 20,974	$ 43,415	$ 50,771	$ 8,546	$ -	$ 123,706
Total Capital Costs Related to Minimum Functionality		$ -	$ -	$ 20,974	$ 1,221,869	$ 439,141	$ 263,901	$ -	$ 1,945,885

	Asset Type								
1.6 CAPITAL COSTS BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06									$ -
1.6.2 Costs for deployment of smart meters to customers other than residential and small general service									$ -
1.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.									$ -
Total Capital Costs Beyond Minimum Functionality		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Smart Meter Capital Costs		$ -	$ -	$ 20,974	$ 1,221,869	$ 439,141	$ 263,901	$ -	$ 1,945,885

2 OM&A Expenses

2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
2.1.1 Maintenance *(may include meter reverification costs, etc.)*								$ -
2.1.2 Other *(please specify)*								$ -
Total Incremental AMCD OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)								
2.2.1 Maintenance								$ -
2.2.2 Other *(please specify)*								$ -
Total Incremental AMRC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)								
2.3.1 Hardware Maintenance *(may include server support, etc.)*								$ -
2.3.2 Software Maintenance *(may include maintenance support, etc.)*				14,927	42,874	52,904		$ 110,705
2.3.2 Other *(please specify)*								$ -
Total Incremental AMCC OM&A Costs	$ -	$ -	$ -	$ 14,927	$ 42,874	$ 52,904	$ -	$ 110,705
2.4 WIDE AREA NETWORK (WAN)								
2.4.1 WAN Maintenance								$ -
2.4.2 Other *(please specify)*								$ -
Total Incremental AMRC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY								
2.5.1 Business Process Redesign								$ -
2.5.2 Customer Communication (may include project communication, etc.)						10,444		$ 10,444
2.5.3 Program Management								$ -
2.5.4 Change Management (may include training, etc.)				6,184	10,963	18,960		$ 36,107
2.5.5 Administration Costs								$ -
2.5.6 Other AMI Expenses *(please specify)*				801	548			$ 1,349
Total Other AMI OM&A Costs Related to Minimum Functionality	$ -	$ -	$ -	$ 6,985	$ 11,511	$ 29,404	$ -	$ 47,900
TOTAL OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY	$ -	$ -	$ -	$ 21,912	$ 54,385	$ 82,308	$ -	$ 158,605
2.6 OM&A COSTS RELATED TO BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual		
2.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06								$ -
2.6.2 Costs for deployment of smart meters to customers other than residential and small general service								$ -
2.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.								$ -
Total OM&A Costs Beyond Minimum Functionality	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Smart Meter OM&A Costs	$ -	$ -	$ -	$ 21,912	$ 54,385	$ 82,308	$ -	$ 158,605

3 Aggregate Smart Meter Costs by Category

3.1	**Capital**								
3.1.1	Smart Meter	$ -	$ -	$ -	$ 1,178,454	$ 388,370	$ 255,355	$ -	$ 1,822,179
3.1.2	Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.3	Computer Software	$ -	$ -	$ 20,974	$ 43,415	$ 50,771	$ 8,546	$ -	$ 123,706
3.1.4	Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.5	Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.6	**Total Capital Costs**	**$ -**	**$ -**	**$ 20,974**	**$ 1,221,869**	**$ 439,141**	**$ 263,901**	**$ -**	**$ 1,945,885**
3.2	**OM&A Costs**								
3.2.1	**Total OM&A Costs**	**$ -**	**$ -**	**$ -**	**$ 21,912**	**$ 54,385**	**$ 82,308**	**$ -**	**$ 158,605**

	2006	2007	2008	2009	2010	2011	2012 and later
Cost of Capital							
Capital Structure[1]							
Deemed Short-term Debt Capitalization			0.0%	0.0%	4.0%	4.0%	4.0%
Deemed Long-term Debt Capitalization	0.0%	0.0%	60.0%	60%	56%	56%	56%
Deemed Equity Capitalization	100.0%	100.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Preferred Shares	0.0%	0.0%	0.0%	0.0%		0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Cost of Capital Parameters							
Deemed Short-term Debt Rate			0.00%	0.00%	0.00%	2.46%	2.46%
Long-term Debt Rate (actual/embedded/deemed)[2]	5.80%	5.80%	6.10%	6.39%	6.02%	5.75%	5.32%
Target Return on Equity (ROE)	0.0%	0.00%	9.00%	8.57%	9.85%	9.58%	9.58%
Return on Preferred Shares	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
WACC	0.00%	0.00%	7.26%	7.26%	7.31%	7.15%	6.91%
Working Capital Allowance							
Working Capital Allowance Rate	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
(% of the sum of Cost of Power + controllable expenses)							
Taxes/PILs							
Aggregate Corporate Income Tax Rate	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%
Capital Tax (until July 1st, 2010)	0.30%	0.225%	0.225%	0.225%	0.075%	0.00%	0.00%
Depreciation Rates							
(expressed as expected useful life in years)							
Smart Meters - years	15	15	15	15	15	15	15
- rate (%)	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
Computer Hardware - years	5	5	5	5	5	5	5
- rate (%)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Computer Software - years	5	5	5	5	5	5	5
- rate (%)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Tools & Equipment - years	10	10	10	10	10	10	10
- rate (%)	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Other Equipment - years	10	10	10	10	10	10	10
- rate (%)	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
CCA Rates							
Smart Meters - CCA Class	47	47	47	47	47	47	47
Smart Meters - CCA Rate	8%	8%	8%	8%	8%	8%	8%
Computer Equipment - CCA Class	50	50	50	50	50	50	50
Computer Equipment - CCA Rate	55%	55%	55%	55%	55%	55%	55%
General Equipment - CCA Class	50	50	50	50	50	50	50
General Equipment - CCA Rate	55%	55%	55%	55%	55%	55%	55%

Assumptions

[1] *Planned smart meter installations occur evenly throughout the year.*

[2] *Fiscal calendar year (January 1 to December 31) used.*

3 *Amortization is done on a striaght line basis and has the "half-year" rule applied.*

	2006	2007	2008	2009	2010	2011	2012 and later
Net Fixed Assets - Smart Meters							
Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ 1,178,454	$ 1,566,824	$ 1,822,179
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ 1,178,454	$ 388,370	$ 255,355	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ 1,178,454	$ 1,566,824	$ 1,822,179	$ 1,822,179
Accumulated Depreciation							
Opening Balance		$ -	$ -	$ -	-$ 39,282	-$ 130,791	-$ 243,758
Amortization expense during year	$ -	$ -	$ -	-$ 39,282	-$ 91,509	-$ 112,967	-$ 121,479
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	-$ 39,282	-$ 130,791	-$ 243,758	-$ 365,236
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ 1,139,172	$ 1,436,033	$ 1,578,421
Closing Balance	$ -	$ -	$ -	$ 1,139,172	$ 1,436,033	$ 1,578,421	$ 1,456,943
Average Net Book Value	$ -	$ -	$ -	$ 569,586	$ 1,287,603	$ 1,507,227	$ 1,517,682
Net Fixed Assets - Computer Hardware							
Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Fixed Assets - Computer Software							
Gross Book Value							
Opening Balance		$ -	$ -	$ 20,974	$ 64,389	$ 115,160	$ 123,706
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ 20,974	$ 43,415	$ 50,771	$ 8,546	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ 20,974	$ 64,389	$ 115,160	$ 123,706	$ 123,706
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	-$ 2,097	-$ 10,634	-$ 28,589	-$ 52,475
Amortization expense during year	$ -	$ -	-$ 2,097	-$ 8,536	-$ 17,955	-$ 23,887	-$ 24,741
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	-$ 2,097	-$ 10,634	-$ 28,589	-$ 52,475	-$ 77,216
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ 18,877	$ 53,755	$ 86,571	$ 71,231
Closing Balance	$ -	$ -	$ 18,877	$ 53,755	$ 86,571	$ 71,231	$ 46,490
Average Net Book Value	$ -	$ -	$ 9,438	$ 36,316	$ 70,163	$ 78,901	$ 58,860
Net Fixed Assets - Tools and Equipment							

Net Fixed Assets - Tools and Equipment

Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation								
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value								
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Net Fixed Assets - Other Equipment

Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation								
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value								
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

	2006	2007	2008	2009	2010	2011	2012 and Later
Average Net Fixed Asset Values (from Sheet 4)							
Smart Meters	$ -	$ -	$ -	$ 569,586	$ 1,287,603	$ 1,507,227	$ 1,517,682
Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Software	$ -	$ -	$ 9,438	$ 36,316	$ 70,163	$ 78,901	$ 58,860
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Net Fixed Assets	**$ -**	**$ -**	**$ 9,438**	**$ 605,902**	**$ 1,357,766**	**$ 1,586,128**	**$ 1,576,542**
Working Capital							
Operating Expenses (from Sheet 2)	$ -	$ -	$ -	$ 21,912	$ 54,385	$ 82,308	$ -
Working Capital Factor (from Sheet 3)	15%	15%	15%	15%	15%	15%	15%
Working Capital Allowance	$ -	$ -	$ -	$ 3,287	$ 8,158	$ 12,346	$ -
Incremental Smart Meter Rate Base	**$ -**	**$ -**	**$ 9,438**	**$ 609,189**	**$ 1,365,924**	**$ 1,598,474**	**$ 1,576,542**
Return on Rate Base							
Capital Structure							
Deemed Short Term Debt	$ -	$ -	$ -	$ -	$ 54,637	$ 63,939	$ 63,062
Deemed Long Term Debt	$ -	$ -	$ 5,663	$ 365,513	$ 764,917	$ 895,146	$ 882,864
Equity	$ -	$ -	$ 3,775	$ 243,676	$ 546,369	$ 639,390	$ 630,617
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Capitalization	$ -	$ -	$ 9,438	$ 609,189	$ 1,365,924	$ 1,598,474	$ 1,576,542
Return on							
Deemed Short Term Debt	$ -	$ -	$ -	$ -	$ -	$ 1,573	$ 1,551
Deemed Long Term Debt	$ -	$ -	$ 345	$ 23,356	$ 46,048	$ 51,471	$ 46,968
Equity	$ -	$ -	$ 340	$ 20,883	$ 53,817	$ 61,254	$ 60,413
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Return on Capital	$ -	$ -	$ 685	$ 44,239	$ 99,865	$ 114,297	$ 108,933
			Error	Error	Error	Error	Error
Operating Expenses	$ -	$ -	$ -	$ 21,912	$ 54,385	$ 82,308	$ -
Amortization Expenses (from Sheet 4)							
Smart Meters	$ -	$ -	$ -	$ 39,282	$ 91,509	$ 112,967	$ 121,479
Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Software	$ -	$ -	$ 2,097	$ 8,536	$ 17,955	$ 23,887	$ 24,741
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Amortization Expense in Year	$ -	$ -	$ 2,097	$ 47,818	$ 109,464	$ 136,853	$ 146,220
Incremental Revenue Requirement before Taxes/PILs	$ -	$ -	$ 2,783	$ 113,969	$ 263,715	$ 333,459	$ 255,153
Calculation of Taxable Income							
Incremental Operating Expenses	$ -	$ -	$ -	$ 21,912	$ 54,385	$ 82,308	$ -
Amortization Expense	$ -	$ -	$ 2,097	$ 47,818	$ 109,464	$ 136,853	$ 146,220
Interest Expense	$ -	$ -	$ 345	$ 23,356	$ 46,048	$ 53,044	$ 48,520
Net Income for Taxes/PILs	$ -	$ -	$ 340	$ 20,883	$ 53,817	$ 61,254	$ 60,413
Grossed-up Taxes/PILs (from Sheet 7)	$ -	$ -	-$ 1,635.38	$ 3,304.89	$ 11,117.76	$ 16,820.89	$ 23,559.73
Revenue Requirement, including Grossed-up Taxes/PILs	$ -	$ -	$ 1,147	$ 117,274	$ 274,832	$ 350,280	$ 278,712

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For PILs Calculation

UCC - Smart Meters

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ 1,131,315.84	$ 1,413,645.77	$ 1,545,694.91
Capital Additions	$ -	$ -	$ -	$ 1,178,454.00	$ 388,370.00	$ 255,355.00	$ -
Retirements/Removals (if applicable)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule	$ -	$ -	$ -	$ 1,178,454.00	$ 1,519,685.84	$ 1,669,000.77	$ 1,545,694.91
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ 589,227.00	$ 194,185.00	$ 127,677.50	$ -
Reduced UCC	$ -	$ -	$ -	$ 589,227.00	$ 1,325,500.84	$ 1,541,323.27	$ 1,545,694.91
CCA Rate Class	47	47	47	47	47	47	47
CCA Rate	8%	8%	8%	8%	8%	8%	8%
CCA	$ -	$ -	$ -	$ 47,138.16	$ 106,040.07	$ 123,305.86	$ 123,655.59
Closing UCC	$ -	$ -	$ -	$ 1,131,315.84	$ 1,413,645.77	$ 1,545,694.91	$ 1,422,039.32

UCC - Computer Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ -	$ 15,206.15	$ 38,318.64	$ 54,052.36	$ 30,519.41
Capital Additions Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Computer Software	$ -	$ -	$ 20,974.00	$ 43,415.00	$ 50,771.00	$ 8,546.00	$ -
Retirements/Removals (if applicable)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule	$ -	$ -	$ 20,974.00	$ 58,621.15	$ 89,089.64	$ 62,598.36	$ 30,519.41
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ 10,487.00	$ 21,707.50	$ 25,385.50	$ 4,273.00	$ -
Reduced UCC	$ -	$ -	$ 10,487.00	$ 36,913.65	$ 63,704.14	$ 58,325.36	$ 30,519.41
CCA Rate Class	50	50	50	50	50	50	50
CCA Rate	55%	55%	55%	55%	55%	55%	55%
CCA	$ -	$ -	$ 5,767.85	$ 20,302.51	$ 35,037.28	$ 32,078.95	$ 16,785.68
Closing UCC	$ -	$ -	$ 15,206.15	$ 38,318.64	$ 54,052.36	$ 30,519.41	$ 13,733.74

UCC - General Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA Rate Class	50	50	50	50	50	50	50
CCA Rate	55%	55%	55%	55%	55%	55%	55%
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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PILs Calculation

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
INCOME TAX							
Net Income	$ -	$ -	$ 339.78	$ 20,882.99	$ 53,817.39	$ 61,253.54	$ 60,413.09
Amortization	$ -	$ -	$ 2,097.40	$ 47,818.10	$ 109,464.17	$ 136,853.37	$ 146,219.80
CCA - Smart Meters	$ -	$ -	$ -	-$ 47,138.16	-$ 106,040.07	-$ 123,305.86	-$ 123,655.59
CCA - Computers	$ -	$ -	-$ 5,767.85	-$ 20,302.51	-$ 35,037.28	-$ 32,078.95	-$ 16,785.68
CCA - Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Change in taxable income	$ -	$ -	-$ 3,330.67	$ 1,260.43	$ 22,204.21	$ 42,722.09	$ 66,191.62
Tax Rate (from Sheet 3)	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%
Income Taxes Payable	$ -	$ -	-$ 1,115.77	$ 415.94	$ 6,883.31	$ 12,068.99	$ 17,375.30
ONTARIO CAPITAL TAX							
Smart Meters	$ -	$ -	$ -	$ 1,139,172.20	$ 1,436,032.93	$ 1,578,421.17	$ 1,456,942.57
Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Software	$ -	$ -	$ 18,876.60	$ 53,755.30	$ 86,571.40	$ 71,230.80	$ 46,489.60
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rate Base	$ -	$ -	$ 18,876.60	$ 1,192,927.50	$ 1,522,604.33	$ 1,649,651.97	$ 1,503,432.17
Less: Exemption	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deemed Taxable Capital	$ -	$ -	$ 18,876.60	$ 1,192,927.50	$ 1,522,604.33	$ 1,649,651.97	$ 1,503,432.17
Ontario Capital Tax Rate (from Sheet 3)	0.300%	0.225%	0.225%	0.225%	0.075%	0.000%	0.000%
Net Amount (Taxable Capital x Rate)	$ -	$ -	$ 42.47	$ 2,684.09	$ 1,141.95	$ -	$ -
Change in Income Taxes Payable	$ -	$ -	-$ 1,115.77	$ 415.94	$ 6,883.31	$ 12,068.99	$ 17,375.30
Change in OCT	$ -	$ -	$ 42.47	$ 2,684.09	$ 1,141.95	$ -	$ -
PIL's	$ -	$ -	-$ 1,073.30	$ 3,100.03	$ 8,025.26	$ 12,068.99	$ 17,375.30
Gross Up PILs							
Tax Rate	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%
Change in Income Taxes Payable	$ -	$ -	-$ 1,677.86	$ 620.81	$ 9,975.81	$ 16,820.89	$ 23,559.73
Change in OCT	$ -	$ -	$ 42.47	$ 2,684.09	$ 1,141.95	$ -	$ -
PIL's	**$ -**	**$ -**	**-$ 1,635.38**	**$ 3,304.89**	**$ 11,117.76**	**$ 16,820.89**	**$ 23,559.73**

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
2006 Q1			Jan-06	2006	Q1	$ -		0.00%	$ -	$ -		
2006 Q2	4.14%	4.68%	Feb-06	2006	Q1	$ -		0.00%	$ -	$ -		
2006 Q3	4.59%	5.05%	Mar-06	2006	Q1	$ -		0.00%	$ -	$ -		
2006 Q4	4.59%	4.72%	Apr-06	2006	Q2	$ -		4.14%	$ -	$ -		
2007 Q1	4.59%	4.72%	May-06	2006	Q2	$ -	$ 614.00	4.14%	$ -	$ 614.00		$ 0.26
2007 Q2	4.59%	4.72%	Jun-06	2006	Q2	$ 614.00	$ 1,766.00	4.14%	$ 2.12	$ 2,382.12		$ 0.26
2007 Q3	4.59%	5.18%	Jul-06	2006	Q3	$ 2,382.12	$ 2,343.00	4.59%	$ 9.11	$ 4,734.23		$ 0.26
2007 Q4	5.14%	5.18%	Aug-06	2006	Q3	$ 4,734.23	$ 2,119.00	4.59%	$ 18.11	$ 6,871.34		$ 0.26
2008 Q1	5.14%	5.18%	Sep-06	2006	Q3	$ 6,871.34	$ 2,322.00	4.59%	$ 26.28	$ 9,219.62		$ 0.26
2008 Q2	4.08%	5.18%	Oct-06	2006	Q4	$ 9,219.62	$ 2,715.00	4.59%	$ 35.27	$ 11,969.89		$ 0.26
2008 Q3	3.35%	5.43%	Nov-06	2006	Q4	$ 11,969.89	$ 2,265.00	4.59%	$ 45.78	$ 14,280.67		$ 0.26
2008 Q4	3.35%	5.43%	Dec-06	2006	Q4	$ 14,280.67	$ 1,896.00	4.59%	$ 54.62	$ 16,231.29	$ 16,231.29	$ 0.26
2009 Q1	2.45%	6.61%	Jan-07	2007	Q1	$ 16,231.29	$ 2,336.00	4.59%	$ 62.08	$ 18,629.37		$ 0.26
2009 Q2	1.00%	6.61%	Feb-07	2007	Q1	$ 18,629.37	$ 2,316.00	4.59%	$ 71.26	$ 21,016.63		$ 0.26
2009 Q3	0.55%	5.67%	Mar-07	2007	Q1	$ 21,016.63	$ 2,751.00	4.59%	$ 80.39	$ 23,848.02		$ 0.26
2009 Q4	0.55%	4.66%	Apr-07	2007	Q2	$ 23,848.02	$ 1,919.00	4.59%	$ 91.22	$ 25,858.24		$ 0.26
2010 Q1	0.55%	4.34%	May-07	2007	Q2	$ 25,858.24	$ 2,778.00	4.59%	$ 98.91	$ 28,735.15		$ 0.26
2010 Q2	0.55%	4.34%	Jun-07	2007	Q2	$ 28,735.15	$ 1,787.00	4.59%	$ 109.91	$ 30,632.06		$ 0.26
2010 Q3	0.89%	4.66%	Jul-07	2007	Q3	$ 30,632.06	$ 1,967.00	4.59%	$ 117.17	$ 32,716.23		$ 0.26
2010 Q4	1.20%	4.01%	Aug-07	2007	Q3	$ 32,716.23	$ 2,507.00	4.59%	$ 125.14	$ 35,348.37		$ 0.26
2011 Q1	1.47%	4.29%	Sep-07	2007	Q3	$ 35,348.37	$ 2,327.00	4.59%	$ 135.21	$ 37,810.58		$ 0.26
2011 Q2	1.47%	4.29%	Oct-07	2007	Q4	$ 37,810.58	$ 2,583.00	5.14%	$ 161.96	$ 40,555.54		$ 0.26
2011 Q3	1.47%	4.29%	Nov-07	2007	Q4	$ 40,555.54	$ 2,106.00	5.14%	$ 173.71	$ 42,835.25		$ 0.26
2011 Q4	1.47%	4.29%	Dec-07	2007	Q4	$ 42,835.25	$ 6,415.00	5.14%	$ 183.48	$ 49,433.73	$ 33,202.44	$ 0.26
2012 Q1	1.47%	4.29%	Jan-08	2008	Q1	$ 49,433.73	$ 3,149.00	5.14%	$ 211.74	$ 52,794.47		$ 0.26
2012 Q2	1.47%	4.29%	Feb-08	2008	Q1	$ 52,794.47	$ 1,892.00	5.14%	$ 226.14	$ 54,912.61		$ 0.26
2012 Q3	1.47%	4.29%	Mar-08	2008	Q1	$ 54,912.61	$ 2,361.00	5.14%	$ 235.21	$ 57,508.82		$ 0.26
2012 Q4	1.47%	4.29%	Apr-08	2008	Q2	$ 57,508.82	$ 2,587.00	4.08%	$ 195.53	$ 60,291.35		$ 0.26
			May-08	2008	Q2	$ 60,291.35	$ 1,927.00	4.08%	$ 204.99	$ 62,423.34		$ 1.00
			Jun-08	2008	Q2	$ 62,423.34	$ 2,516.00	4.08%	$ 212.24	$ 65,151.58		$ 1.00
			Jul-08	2008	Q3	$ 65,151.58	$ 2,637.00	3.35%	$ 181.88	$ 67,970.46		$ 1.00
			Aug-08	2008	Q3	$ 67,970.46	$ 3,506.00	3.35%	$ 189.75	$ 71,666.21		$ 1.00
			Sep-08	2008	Q3	$ 71,666.21	$ 6,951.00	3.35%	$ 200.07	$ 78,817.28		$ 1.00
			Oct-08	2008	Q4	$ 78,817.28	$ 8,147.00	3.35%	$ 220.03	$ 87,184.31		$ 1.00
			Nov-08	2008	Q4	$ 87,184.31	$ 9,104.00	3.35%	$ 243.39	$ 96,531.70		$ 1.00
			Dec-08	2008	Q4	$ 96,531.70	$ 4,749.00	3.35%	$ 269.48	$ 101,550.18	$ 52,116.45	$ 1.00
			Jan-09	2009	Q1	$ 101,550.18	$ 9,157.00	2.45%	$ 207.33	$ 110,914.51		$ 1.00
			Feb-09	2009	Q1	$ 110,914.51	$ 10,237.00	2.45%	$ 226.45	$ 121,377.96		$ 1.00
			Mar-09	2009	Q1	$ 121,377.96	$ 10,050.00	2.45%	$ 247.81	$ 131,675.77		$ 1.00
			Apr-09	2009	Q2	$ 131,675.77	$ 9,472.00	1.00%	$ 109.73	$ 141,257.50		$ 1.00
			May-09	2009	Q2	$ 141,257.50	$ 8,762.00	1.00%	$ 117.71	$ 150,137.21		$ 1.00
			Jun-09	2009	Q2	$ 150,137.21	$ 8,686.00	1.00%	$ 125.11	$ 158,948.32		$ 1.00
			Jul-09	2009	Q3	$ 158,948.32	$ 10,418.00	0.55%	$ 72.85	$ 169,439.17		$ 1.00
			Aug-09	2009	Q3	$ 169,439.17	$ 8,605.00	0.55%	$ 77.66	$ 178,121.83		$ 1.00
			Sep-09	2009	Q3	$ 178,121.83	$ 10,148.00	0.55%	$ 81.64	$ 188,351.47		$ 1.00
			Oct-09	2009	Q4	$ 188,351.47	$ 8,685.00	0.55%	$ 86.33	$ 197,122.80		$ 1.00
			Nov-09	2009	Q4	$ 197,122.80	$ 9,280.00	0.55%	$ 90.35	$ 206,493.15		$ 1.00
			Dec-09	2009	Q4	$ 206,493.15	$ 9,580.00	0.55%	$ 94.64	$ 216,167.79	$ 114,617.61	$ 1.00
			Jan-10	2010	Q1	$ 216,167.79	$ 9,217.00	0.55%	$ 99.08	$ 225,483.87		$ 1.00
			Feb-10	2010	Q1	$ 225,483.87	$ 7,128.00	0.55%	$ 103.35	$ 232,715.22		$ 1.00
			Mar-10	2010	Q1	$ 232,715.22	$ 10,904.00	0.55%	$ 106.66	$ 243,725.88		$ 1.00
			Apr-10	2010	Q2	$ 243,725.88	$ 9,516.00	0.55%	$ 111.71	$ 253,353.59		$ 1.00
			May-10	2010	Q2	$ 253,353.59	$ 9,230.00	0.55%	$ 116.12	$ 262,699.71		$ 2.00
			Jun-10	2010	Q2	$ 262,699.71	$ 12,883.00	0.55%	$ 120.40	$ 275,703.11		$ 2.00
			Jul-10	2010	Q3	$ 275,703.11	$ 21,158.00	0.89%	$ 204.48	$ 297,065.59		$ 2.00
			Aug-10	2010	Q3	$ 297,065.59	$ 17,465.00	0.89%	$ 220.32	$ 314,750.91		$ 2.00
			Sep-10	2010	Q3	$ 314,750.91	$ 20,366.00	0.89%	$ 233.44	$ 335,350.35		$ 2.00
			Oct-10	2010	Q4	$ 335,350.35	$ 17,735.00	1.20%	$ 335.35	$ 353,420.70		$ 2.00
			Nov-10	2010	Q4	$ 353,420.70	$ 18,676.00	1.20%	$ 353.42	$ 372,450.12		$ 2.00
			Dec-10	2010	Q4	$ 372,450.12	$ 17,508.00	1.20%	$ 372.45	$ 390,330.57	$ 174,162.78	$ 2.00
			Jan-11	2011	Q1	$ 390,330.57	$ 18,812.27	1.47%	$ 478.15	$ 409,620.99		$ 2.00
			Feb-11	2011	Q1	$ 409,620.99	$ 19,439.17	1.47%	$ 501.79	$ 429,561.95		$ 2.00
			Mar-11	2011	Q1	$ 429,561.95	$ 18,794.02	1.47%	$ 526.21	$ 448,882.18		$ 2.00
			Apr-11	2011	Q2	$ 448,882.18	$ 19,400.68	1.47%	$ 549.88	$ 468,832.74		$ 2.00
			May-11	2011	Q2	$ 468,832.74	$ 18,514.69	1.47%	$ 574.32	$ 487,921.75		$ 2.50
			Jun-11	2011	Q2	$ 487,921.75	$ 21,461.51	1.47%	$ 597.70	$ 509,980.96		$ 2.50
			Jul-11	2011	Q3	$ 509,980.96	$ 23,291.03	1.47%	$ 624.73	$ 533,896.72		$ 2.50
			Aug-11	2011	Q3	$ 533,896.72	$ 24,101.24	1.47%	$ 654.02	$ 558,651.98		$ 2.50
			Sep-11	2011	Q3	$ 558,651.98	$ 24,101.24	1.47%	$ 684.35	$ 583,437.57		$ 2.50
			Oct-11	2011	Q4	$ 583,437.57	$ 21,461.51	1.47%	$ 714.71	$ 605,613.79		$ 2.50
			Nov-11	2011	Q4	$ 605,613.79	$ 20,000.00	1.47%	$ 741.88	$ 626,355.67		$ 2.50
			Dec-11	2011	Q4	$ 626,355.67	$ 20,000.00	1.47%	$ 767.29	$ 647,122.96	$ 256,792.39	$ 2.50
			Jan-12	2012	Q1	$ 647,122.96	$ 20,000.00	1.47%	$ 792.73	$ 667,915.69		$ 2.50
			Feb-12	2012	Q1	$ 667,915.69	$ 20,000.00	1.47%	$ 818.20	$ 688,733.89		$ 2.50
			Mar-12	2012	Q1	$ 688,733.89	$ 20,000.00	1.47%	$ 843.70	$ 709,577.59		$ 2.50
			Apr-12	2012	Q2	$ 709,577.59	$ 20,000.00	1.47%	$ 869.23	$ 730,446.82		$ 2.50
			May-12	2012	Q2	$ 730,446.82		1.47%	$ 894.80	$ 731,341.62		
			Jun-12	2012	Q2	$ 731,341.62		1.47%	$ 895.89	$ 732,237.51		
			Jul-12	2012	Q3	$ 732,237.51		1.47%	$ 896.99	$ 733,134.50		
			Aug-12	2012	Q3	$ 733,134.50		1.47%	$ 898.09	$ 734,032.59		
			Sep-12	2012	Q3	$ 734,032.59		1.47%	$ 899.19	$ 734,931.78		
			Oct-12	2012	Q4	$ 734,931.78		1.47%	$ 900.29	$ 735,832.07		
			Nov-12	2012	Q4	$ 735,832.07		1.47%	$ 901.39	$ 736,733.46		
			Dec-12	2012	Q4	$ 736,733.46		1.47%	$ 902.50	$ 737,635.96	$ 90,513.00	
			Total Funding Adder Revenues Collected				**$ 711,601.36**		**$ 26,034.60**	**$ 737,635.96**	**$ 737,635.96**	

Check if applicable		
	Smart Meter Funding Adder (SMFA)	
X	Smart Meter Disposition Rider (SMDR)	**The SMDR is calculated based on costs to December 31, 2011**
	Smart Meter Incremental Revenue Requirement Rate Rider (SMIRR)	**The SMIRR is calculated based on the incremental revenue requirement associated with the recovery of capital related costs to December 31, 2012 and associated OM&A.**

	2006	2007	2008	2009	2010	2011	2012 and later	Total
Deferred and forecasted Smart Meter Incremental Revenue Requirement (from Sheet 5)	$ -	$ -	$ 1,147.24	$ 117,274.29	$ 274,832.34	$ 350,279.57	$ 278,712.28	$ 1,022,245.71
SMFA Revenues and carrying charges (from Sheet 8)	$ 16,231.29	$ 33,202.44	$ 52,116.45	$ 114,617.61	$ 174,162.78	$ 256,792.39	$ 90,513.00	$ 737,635.96
Net Deferred Revenue Requirement	-$ 16,231.29	-$ 33,202.44	-$ 50,969.21	$ 2,656.68	$ 100,669.56	$ 93,487.18	$ 188,199.28	$ 284,609.75
Number of Metered Customers (average for 2012 test year)							9833	

Calculation of Smart Meter Disposition Rider (per metered customer per month)

Years for collection or refunding	1	
Deferred Incremental Revenue Requirement from 2006 to December 31, 2011	$ 743,533.43	
SMFA Revenues collected from 2006 to 2012 test year (inclusive)	$ 737,635.96	
Net Deferred Revenue Requirement	$ 5,897.47	
SMDR May 1, 2012 to April 30, 2013	$ 0.05	Match
Check: Forecasted SMDR Revenues	$ 5,899.80	

Appendix D

Account Descriptions	Account Number	2005 Opening Principal Amounts as of Jan-1-05	2005 Transactions Debit / (Credit) during 2005 excluding interest and adjustments [4]	2005 Board-Approved Disposition during 2005	2005 Adjustments during 2005 - other [3]	2005 Closing Principal Balance as of Dec-31-05	2005 Opening Interest Amounts as of Jan-1-05	2005 Interest Jan-1 to Dec-31-05	2005 Board-Approved Disposition during 2005	2005 Adjustments during 2005 - other [3]	2005 Closing Interest Amounts as of Dec-31-05
Group 1 Accounts											
LV Variance Account	1550					$ -					$ -
RSVA - Wholesale Market Service Charge	1580					$ -					$ -
RSVA - Retail Transmission Network Charge	1584					$ -					$ -
RSVA - Retail Transmission Connection Charge	1586					$ -					$ -
RSVA - Power (excluding Global Adjustment)	1588					$ -					$ -
RSVA - Power - Sub-Account - Global Adjustment	1588					$ -					$ -
Recovery of Regulatory Asset Balances	1590					$ -					$ -
Disposition and Recovery of Regulatory Balances (2008)[10]	1595					$ -					$ -
Disposition and Recovery of Regulatory Balances (2009)[10]	1595					$ -					$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -	$ 37,527		$ -	$ 37,527	$ 1,783	$ -			$ 1,783
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -	$ 50,522		$ -	$ 50,522	$ 859	$ -			$ 859
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -	$ -		$ -	$ -	$ -	$ -			$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -	$ -		$ -	$ -	$ -	$ -			$ -
Retail Cost Variance Account - Retail	1518	$ 39,165	$ 10,783		$ -	$ 49,948	$ -	$ -			$ -
Misc. Deferred Debits	1525	$ -	$ -		$ -	$ -	$ -	$ -			$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -					$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -					$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -					$ -
Smart Grid Capital Deferral Account	1534					$ -					$ -
Smart Grid OM&A Deferral Account	1535					$ -					$ -
Smart Grid Funding Adder Deferral Account	1536					$ -					$ -
Retail Cost Variance Account - STR	1548	$ 4,357	$ 7,595		$ -	$ 11,952	$ -	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -	$ -		$ -	$ -	$ -	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ -	$ -		$ -	$ -	$ -	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	$ -	$ -		$ -	$ -	$ -	$ -			$ -
Smart Meter OM&A Variance	1556	$ -	$ -		$ -	$ -	$ -	$ -			$ -
Conservation and Demand Management (CDM) Expenditures and Recoveries	1565	-$ 64,068	$ -		$ -	-$ 64,068	$ -	$ -			$ -
CDM Contra	1566	$ 64,068	$ -		$ -	$ 64,068	$ -	$ -			$ -
Qualifying Transition Costs [5]	1570	$ -	$ -		$ -	$ -	$ -	$ -			$ -
Pre-market Opening Energy Variance [5]	1571	$ -	$ -		$ -	$ -	$ -	$ -			$ -
Extra-Ordinary Event Costs	1572	$ -	$ -		$ -	$ -	$ -	$ -			$ -
Deferred Rate Impact Amounts	1574	$ -	$ -		$ -	$ -	$ -	$ -			$ -
RSVA - One-time	1582	$ 12,399	$ 15,222		$ 66,214	$ 93,835	$ 7,538	$ 6,033			$ 13,571
Other Deferred Credits	2425					$ -					$ -
Group 2 Sub-Total		$ 55,921	$ 121,649	$ -	$ 66,214	$ 243,784	$ 10,180	$ 6,033	$ -	$ -	$ 16,213
Deferred Payments in Lieu of Taxes	1562					$ -					$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592					$ -					$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592					$ -					$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ 55,921	$ 121,649	$ -	$ 66,214	$ 243,784	$ 10,180	$ 6,033	$ -	$ -	$ 16,213
Special Purpose Charge Assessment Variance Account	**1521**										
Total including Account 1521 [1]		$ 55,921	$ 121,649	$ -	$ 66,214	$ 243,784	$ 10,180	$ 6,033	$ -	$ -	$ 16,213
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [8]	1563					$ -					$ -
Board-Approved CDM Variance Account	1567										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592					$ -					$ -
Disposition and Recovery of Regulatory Balances[10]	1595					$ -					$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

[1] Applicants may wish to propose kWh as the allocator for account 1521 appending a final decision of the Board

[2] Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, etc.

[2A] Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the 2006 EDR and account 1595 during the 2008 EDR and subsequent years as ordered by the Board.

[3] Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

[4] Although the Global Adjustment Account is not reported separately under 2.1.7, please provide a breakdown in rows 28 and 29.

[5] Closed April 30, 2002

[6] For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

[7] Please describe "other" components of 1508 and add more component lines if necessary.

[8] 1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligation to the ratepayer.

[9] If the LDC's 2011 rate year started January 1, the projected interest is recorded from January 1, 2011 to April 30, 2012 on the December 31, 2010 balance adjusted for the disposed balances approved by the Board in the 2011 rate decision. If the LDC's 2011 rate year started May 1, the projected interest is recorded from January 1, 2011 to April 30, 11 on the December 31, 2010 balance. The projected interested is recorded from May 1, 2011 to April 30, 2012 on the December 31, 2010 balance adjusted for the disposed balances approved by the Board in the 2011 rate decision.

[10] Include Account 1595 as part of Group 1 accounts (line 31) for review and disposition if the recovery (or refund) period has been completed, and the audited financial statements support the underlying residual balance in account 1595. If the recovery (or refund) period has not been completed, include the balances in Account 1595 on a memo basis only (line 82).

2006

Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [6]	Board-Approved Disposition during 2006 [2, 2A]	Adjustments during 2006 - other [3]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [2, 2A]	Adjustments during 2006 - other [3]	Closing Interest Amounts as of Dec-31-06
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 37,527	$ 7,716	$ -		$ 45,243	$ 1,783	$ 1,886	$ -		$ 3,669
$ 50,522	$ 19,147	$ -		$ 69,669	$ 859	$ 2,824	$ -		$ 3,682
$ -	$ -	$ -		$ -	$ -	$ -	$ -		$ -
$ -	$ -	$ -		$ -	$ -	$ -	$ -		$ -
$ 49,948	$ 10,671	$ 39,165		$ 21,454	$ -	$ 1,911	$ 3,785		-$ 1,874
$ -	$ -	$ -		$ -	$ -	$ -	$ -		$ -
				$ -	$ -				$ -
				$ -	$ -				$ -
				$ -	$ -				$ -
				$ -	$ -				$ -
				$ -	$ -				$ -
				$ -	$ -				$ -
$ 11,952	$ 10,364	$ -		$ 22,315	$ -	$ 876	$ -		$ 876
$ -	$ -	$ -		$ -	$ -	$ -	$ -		$ -
$ -	-$ 16,040	$ -		-$ 16,040	$ -	-$ 190	$ -		-$ 190
$ -	$ -	$ -		$ -	$ -	$ -	$ -		$ -
$ -	$ -	$ -		$ -	$ -	$ -	$ -		$ -
-$ 64,068	$ 41,731	$ -		-$ 22,337	$ -	$ -	$ -		$ -
$ 64,068	-$ 41,731	$ -		$ 22,337	$ -	$ -	$ -		$ -
$ -		$ -		$ -	$ -	$ -	$ -		$ -
$ -		$ -		$ -	$ -	$ -	$ -		$ -
$ -	$ -	$ -		$ -	$ -	$ -	$ -		$ -
$ -	$ -	$ -		$ -	$ -	$ -	$ -		$ -
$ 93,835		$ 63,476		$ 30,359	$ 13,571	-$ 12,422	$ 15,137		-$ 13,988
$ -	$ -			$ -	$ -				$ -
$ 243,784	$ 31,858	$ 102,641	$ -	$ 173,000	$ 16,213	-$ 5,115	$ 18,922	$ -	-$ 7,825
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ 243,784	$ 31,858	$ 102,641	$ -	$ 173,000	$ 16,213	-$ 5,115	$ 18,922	$ -	-$ 7,825
$ 243,784	$ 31,858	$ 102,641	$ -	$ 173,000	$ 16,213	-$ 5,115	$ 18,922	$ -	-$ 7,825
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -

1

2007

Opening Principal Amounts as of Jan-1-07	Transactions Debit / (Credit) during 2007 excluding interest and adjustments [6]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [3]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec-31-07	Board-Approved Disposition during 2007	Adjustments during 2007 - other [3]	Closing Interest Amounts as of Dec-31-07
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 45,243	$ -		$ -	$ 45,243	$ 3,669	$ 2,139			$ 5,808
$ 69,669	$ -		$ -	$ 69,669	$ 3,682	$ 3,294			$ 6,976
$ -	$ -		$ -	$ -	$ -	$ -			$ -
$ -	$ -		$ -	$ -	$ -	$ -			$ -
$ 21,454	$ 3,401		$ -	$ 24,855	-$ 1,874	$ 1,075			-$ 798
$ -	$ -		$ -	$ -	$ -	$ -			$ -
				$ -					$ -
				$ -					$ -
				$ -					$ -
				$ -					$ -
				$ -					$ -
				$ -					$ -
$ 22,315	$ 8,113		$ -	$ 30,428	$ 876	$ 1,252			$ 2,128
$ -	$ -		$ -	$ -	$ -	$ -			$ -
-$ 16,040	-$ 31,879		$ -	-$ 47,919	-$ 190	-$ 1,378			-$ 1,568
$ -	$ -		$ -	$ -	$ -	$ -			$ -
$ -	$ -		$ -	$ -	$ -	$ -			$ -
-$ 22,337	$ 69,388		-$ 48,083	-$ 1,032	$ -	$ -			$ -
$ 22,337	-$ 69,388		$ 48,083	$ 1,032	$ -	$ -			$ -
$ -			$ -	$ -	$ -	$ -			$ -
$ -			$ -	$ -	$ -	$ -			$ -
$ -	$ -		$ -	$ -	$ -	$ -			$ -
$ -	$ -		$ -	$ -	$ -	$ -			$ -
$ 30,359			$ -	$ 30,359	-$ 13,988	$ 721			-$ 13,267
$ -	$ -		$ -	$ -	$ -				$ -
$ 173,000	-$ 20,365	$ -	-$ 0	$ 152,635	-$ 7,825	$ 7,102	$ -	$ -	-$ 722
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ 173,000	-$ 20,365	$ -	-$ 0	$ 152,635	-$ 7,825	$ 7,102	$ -	$ -	-$ 722
$ 173,000	-$ 20,365	$ -	-$ 0	$ 152,635	-$ 7,825	$ 7,102	$ -	$ -	-$ 722
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -

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2

2008

Opening Principal Amounts as of Jan-1-08	Transactions Debit / (Credit) during 2008 excluding interest and adjustments [6]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [3]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec-31-08	Board-Approved Disposition during 2008	Adjustments during 2008 - other [3]	Closing Interest Amounts as of Dec-31-08
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 45,243	-$ 45,243			-$ 0	$ 5,808	$ 1,295	$ 7,103		$ 0
$ 69,669	-$ 69,669			$ 0	$ 6,976	$ 1,995	$ 8,971		-$ 0
$ -	$ -			$ -	$ -	$ -	$ -		$ -
$ -	$ -			$ -	$ -	$ -	$ -		$ -
$ 24,855	$ 6,720			$ 31,575	-$ 798	$ 1,083	$ -		$ 284
$ -	$ -			$ -	$ -	$ -	$ -		$ -
				$ -					$ -
				$ -					$ -
				$ -					$ -
				$ -					$ -
				$ -					$ -
				$ -					$ -
$ 30,428	$ 3,467			$ 33,896	$ 2,128	$ 1,298	$ -		$ 3,426
$ -	$ 20,974			$ 20,974	$ -	$ -	$ -		$ -
-$ 47,919	-$ 49,528			-$ 97,447	-$ 1,568	-$ 2,069	$ -		-$ 3,637
$ -	$ -			$ -	$ -	$ -	$ -		$ -
$ -	$ -			$ -	$ -	$ -	$ -		$ -
-$ 1,032	$ 1,032			$ 0	$ -	$ -	$ -		$ -
$ 1,032	-$ 1,032			-$ 0	$ -	$ -	$ -		$ -
$ -				$ -	$ -	$ -	$ -		$ -
$ -				$ -	$ -	$ -	$ -		$ -
$ -	$ -			$ -	$ -	$ -	$ -		$ -
$ -	$ -			$ -	$ -	$ -	$ -		$ -
$ 30,359				$ 30,359	-$ 13,267	$ 605	$ -		-$ 12,662
$ -	$ -			$ -	$ -		$ -		$ -
$ 152,635	-$ 133,278	$ -	$ -	$ 19,358	-$ 722	$ 4,207	$ 16,074	$ -	-$ 12,589
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ 152,635	-$ 133,278	$ -	$ -	$ 19,358	-$ 722	$ 4,207	$ 16,074	$ -	-$ 12,589
$ 152,635	-$ 133,278	$ -	$ -	$ 19,358	-$ 722	$ 4,207	$ 16,074	$ -	-$ 12,589
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -

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2009

Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [6]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [3]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [3]	Closing Interest Amounts as of Dec-31-09
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
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$ -				$ -	$ -				$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
-$ 0	$ -			-$ 0	$ 0	$ -			$ 0
$ 0	$ -			$ 0	-$ 0	$ -			-$ 0
$ -	$ -			$ -	$ -	$ -			$ -
	$ -			$ -	$ -	$ -			$ -
$ -	$ 5,937			$ 5,937	$ -	$ 4			$ 4
$ 31,575	$ 10,027			$ 41,602	$ 284	$ 393			$ 677
$ -	$ -			$ -	$ -	$ -			$ -
	$ -			$ -	$ -	$ -			$ -
	$ -			$ -	$ -	$ -			$ -
	$ -			$ -	$ -	$ -			$ -
	$ -			$ -	$ -	$ -			$ -
	$ -			$ -	$ -	$ -			$ -
	$ -			$ -	$ -	$ -			$ -
$ 33,896	$ 930			$ 34,826	$ 3,426	$ 407			$ 3,833
$ 20,974	$ 1,252,445			$ 1,273,420	$ -	$ 1,109			$ 1,109
-$ 97,447	-$ 142,251			-$ 239,698	-$ 3,637	$ -			-$ 3,637
$ -	$ -			$ -	$ -	$ -			$ -
$ -	$ 21,112			$ 21,112	$ -	$ 12			$ 12
$ 0	$ -			$ 0	$ -	$ -			$ -
-$ 0	$ -			-$ 0	$ -	$ -			$ -
$ -				$ -	$ -	$ -			$ -
$ -				$ -	$ -	$ -			$ -
$ -	$ -			$ -	$ -	$ -			$ -
$ -	$ -			$ -	$ -	$ -			$ -
$ 30,359				$ 30,359	-$ 12,662	$ 174			-$ 12,488
$ -	$ -			$ -	$ -				$ -
$ 19,358	$ 1,148,200	$ -	$ -	$ 1,167,558	-$ 12,589	$ 2,098	$ -	$ -	-$ 10,491
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ 19,358	$ 1,148,200	$ -	$ -	$ 1,167,558	-$ 12,589	$ 2,098	$ -	$ -	-$ 10,491
$ 19,358	$ 1,148,200	$ -	$ -	$ 1,167,558	-$ 12,589	$ 2,098	$ -	$ -	-$ 10,491
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -

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2

2010

Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [6]	Board-Approved Disposition during 2010	Other [3] Adjustments during Q1 2010	Other [3] Adjustments during Q2 2010	Other [3] Adjustments during Q3 2010	Other [3] Adjustments during Q4 2010	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [3]	Closing Interest Amounts as of Dec-31-10
$ -	-$ 92,482	$ 274,919	$ 138,860			-$ 4,539	-$ 233,080	$ -	-$ 891	$ 18,082	$ 17,350	-$ 1,623
$ -	-$ 243,333	-$ 655,081	-$ 707,732		-$ 351	-$ 26,830	-$ 323,165	$ -	-$ 3,172	-$ 22,154	-$ 21,187	-$ 2,205
$ -	$ 77,520	-$ 17,994	-$ 27,536			-$ 39,253	$ 28,725	$ -	$ 34	-$ 30,235	-$ 30,272	-$ 3
$ -	$ 51,865	-$ 6,252	$ 7,827			-$ 24,385	$ 41,559	$ -	$ 283	-$ 26,258	-$ 26,253	$ 288
$ -	$ 449,908	$ 826,340	$ 1,312,412			-$ 844,538	$ 91,442	$ -	$ 10,724	$ 251	$ 35,712	$ 46,185
$ -	-$ 149,055	$ 118,023	$ 165,711			$ 41,219	-$ 60,148	$ -	-$ 4,732	$ 26,846	$ 27,904	-$ 3,674
$ -	-$ 9,899	-$ 40,635	-$ 15,817				$ 14,919	$ -	-$ 44		-$ 14,875	-$ 14,919
$ -	$ 857	-$ 31,715	-$ 3,879			-$ 32,245	-$ 3,552	$ -	$ 253		$ 3,299	$ 3,552
$ -	-$ 224,685		$ -				-$ 224,685	$ -	-$ 599			-$ 599
$ -	-$ 139,304	$ 467,605	$ 869,846	$ -	-$ 351	-$ 930,571	-$ 667,985	$ -	$ 1,856	-$ 33,468	-$ 8,322	$ 27,002
$ -	$ 9,751	$ 349,582	$ 704,135	$ -	-$ 351	-$ 971,790	-$ 607,837	$ -	$ 6,588	-$ 60,314	-$ 36,226	$ 30,676
$ -	-$ 149,055	$ 118,023	$ 165,711	$ -	$ -	$ 41,219	-$ 60,148	$ -	-$ 4,732	$ 26,846	$ 27,904	-$ 3,674
-$ 0	$ -	$ -	$ -			$ -	-$ 0	$ 0	$ -			$ 0
$ 0	$ -	$ -	$ -			$ -	$ 0	-$ 0	$ -			-$ 0
$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -
$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -
$ 5,937	$ 3,222	$ -	$ -			$ -	$ 9,158	$ 4	$ 79			$ 83
$ 41,602	$ 1,678	$ -	$ -			$ -	$ 43,281	$ 677	$ 340			$ 1,017
$ -	$ -	$ -	$ -			$ 36,872	$ 36,872	$ -	$ -			$ -
$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -
$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -
$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -
$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -
$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -
$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -
$ 34,826	$ 1,397	$ -	$ -			$ -	$ 36,223	$ 3,833	$ 352			$ 4,185
$ 1,273,420	$ 440,710	$ -	$ -			$ -	$ 1,714,130	$ 1,109	$ 8,912			$ 10,020
-$ 239,698	-$ 179,374	$ -	$ -			$ -	-$ 419,071	-$ 3,637	$ -			-$ 3,637
$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -
$ 21,112	$ 54,387	$ -	$ 801			$ -	$ 76,300	$ 12	$ 413			$ 425
$ 0	$ -	$ -	$ -			$ -	$ 0	$ -	$ -			$ -
-$ 0	$ -	$ -	$ -			$ -	$ 0	$ -	$ -			$ -
$ -		$ -	$ -			$ -	$ -	$ -	$ -			$ -
$ -		$ -	$ -			$ -	$ -	$ -	$ -			$ -
$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -
$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -
$ 30,359		$ -	$ -			$ -	$ 30,359	-$ 12,488	$ 121			-$ 12,367
$ -	$ -	$ -	$ -			$ -	$ -	$ -				$ -
$ 1,167,558	$ 322,020	$ -	$ 801	$ -	$ -	$ 36,872	$ 1,527,251	-$ 10,491	$ 10,217	$ -	$ -	-$ 274
$ -							$ -	$ -				$ -
$ -							$ -	$ -				$ -
$ -						$ 31,574	$ 31,574	$ -				$ -
$ 1,167,558	$ 182,716	$ 467,605	$ 870,647	$ -	-$ 351	-$ 893,699	$ 859,266	-$ 10,491	$ 12,073	-$ 33,468	-$ 8,322	$ 26,728
							$ -	$ -				$ -
$ 1,167,558	$ 182,716	$ 467,605	$ 870,647	$ -	-$ 351	-$ 893,699	$ 859,266	-$ 10,491	$ 12,073	-$ 33,468	-$ 8,322	$ 26,728
$ -							$ -	$ -				$ -
							$ -	$ -				$ -
$ -						-$ 31,574	-$ 31,574	$ -				$ -
$ -							$ -	$ -				$ -

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3

2011				Projected Interest on Dec-31-10 Balances			2.1.7 RRR	
Principal Disposition during 2011 - instructed by Board	Interest Disposition during 2011 - instructed by Board	Closing Principal Balances as of Dec 31-10 Adjusted for Dispositions during 2011	Closing Interest Balances as of Dec 31-10 Adjusted during 2011 Disposition	Projected Interest from Jan 1, 2011 to December 31, 2011 on Dec 31 -10 balance adjusted for disposition during 2011 [9]	Projected Interest from January 1, 2012 to April 30, 2012 on Dec 31 -10 balance adjusted for disposition during 2011 [9, 10]	Total Claim	As of Dec 31-10 [4]	Variance RRR vs. 2010 Balance *(Principal + Interest)*
-$ 136,059	-$ 1,804	-$ 97,021	$ 181	-$ 3,426	-$ 1,142	-$ 101,408	-$ 234,703	$ -
-$ 57,776	-$ 10,305	-$ 265,389	$ 8,100	-$ 4,751	-$ 1,584	-$ 263,623	-$ 325,368	$ 2
$ 3,215	-$ 333	$ 25,510	$ 330	$ 422	$ 141	$ 26,403	$ 28,722	$ -
$ 10,891	$ 48	$ 30,668	$ 240	$ 611	$ 204	$ 31,723	$ 42,157	$ 310
$ 523,460	$ 27,266	-$ 432,018	$ 18,919	$ 1,344	$ 448	-$ 411,307	$ 137,630	$ 3
$ 47,668	$ 2,755	-$ 107,816	-$ 6,429	-$ 884	-$ 295	-$ 115,424	-$ 63,822	$ -
		$ 14,919	-$ 14,919	$ 219	$ 73	$ 292	$ -	$ -
		-$ 3,552	$ 3,552	-$ 52	-$ 17	-$ 70		$ -
		-$ 224,685	-$ 599	-$ 3,303	-$ 1,101	-$ 229,688	-$ 225,547	-$ 263
$ 391,399	$ 17,627	-$ 1,059,384	$ 9,375	-$ 9,819	-$ 3,273	-$ 1,063,102	-$ 640,931	$ 52
$ 343,731	$ 14,872	-$ 951,568	$ 15,804	-$ 8,935	-$ 2,978	-$ 947,678	-$ 577,109	$ 52
$ 47,668	$ 2,755	-$ 107,816	-$ 6,429	-$ 884	-$ 295	-$ 115,424	-$ 63,822	$ -
		-$ 0	$ 0	-$ 0	-$ 0	$ 0		-$ 0
		$ 0	-$ 0	$ 0	$ 0	-$ 0		$ 0
		$ -	$ -	$ -	$ -	$ -		$ -
		$ -	$ -	$ -	$ -	$ -		$ -
		$ 9,158	$ 83	$ 135	$ 45	$ 9,421	$ 9,241	-$ 1
		$ 43,281	$ 1,017	$ 636	$ 212	$ 45,145	$ 44,297	-$ 0
		$ 36,872	$ -	$ 542	$ 181	$ 37,595	$ 36,872	$ -
				$ -	$ -	$ -		$ -
				$ -	$ -	$ -		$ -
				$ -	$ -	$ -		$ -
				$ -	$ -	$ -		$ -
				$ -	$ -	$ -		$ -
				$ -	$ -	$ -		$ -
		$ 36,223	$ 4,185	$ 532	$ 177	$ 41,118	$ 40,407	-$ 1
		$ 1,714,130	$ 10,020	$ 25,198	$ 8,399	$ 1,757,747	$ 1,289,072	-$ 435,078
		-$ 419,071	-$ 3,637	-$ 6,160	-$ 2,053	-$ 430,922		$ 422,709
		$ -	$ -	$ -	$ -	$ -		$ -
		$ 76,300	$ 425	$ 1,122	$ 374	$ 78,221	$ 76,722	-$ 3
		$ 0	$ -	$ 0	$ 0	$ 0		-$ 0
		$ 0	$ -	-$ 0	-$ 0	$ 0		$ 0
		$ -	$ -	$ -	$ -	$ -		$ -
		$ -	$ -	$ -	$ -	$ -		$ -
		$ -	$ -	$ -	$ -	$ -		$ -
		$ -	$ -	$ -	$ -	$ -		$ -
		$ 30,359	-$ 12,367	$ 446	$ 149	$ 18,587	$ 17,991	-$ 1
		$ -	$ -	$ -	$ -	$ -		$ -
$ -	$ -	$ 1,527,251	-$ 274	$ 22,451	$ 7,484	$ 1,556,911	$ 1,514,602	-$ 12,375
		$ -	$ -			$ -		$ -
		$ -	$ -			$ -		$ -
		$ 31,574	$ -			$ 31,574		-$ 31,574
$ 391,399	$ 17,627	$ 467,867	$ 9,101	$ 12,631	$ 4,210	$ 525,384	$ 873,671	
						$ -		$ -
$ 391,399	$ 17,627	$ 467,867	$ 9,101	$ 12,631	$ 4,210	$ 525,384	$ 873,671	$ -
						$ -		$ -
						$ -		$ -
						-$ 31,574		$ 31,574
						$ -		$ -

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Accounts that produced a variance on the 2012 continuity schedule are listed below.

Account Descriptions	Account Number	Variance RRR vs. 2010 Balance *(Principal + Interest)*	Explanation
Group 1 Accounts			
RSVA - Wholesale Market Service Charge	1580	$ 2.00	Immaterial, rounding
RSVA - Retail Transmission Connection Charge	1586	$ 310.00	Immaterial, rounding
RSVA - Power (excluding Global Adjustment)	1588	$ 3.00	Immaterial, rounding
Disposition and Recovery of Regulatory Balances (2009)[10]	1595	$ (263.00)	Immaterial, rounding
Group 2 Accounts			
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ (0.06)	Immaterial, rounding
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 0.16	Immaterial, rounding
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ (0.52)	Immaterial, rounding
Retail Cost Variance Account - Retail	1518	$ (0.12)	Immaterial, rounding
Retail Cost Variance Account - STR	1548	$ (0.96)	Immaterial, rounding
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ (435,077.85)	This account varies from the RRR reporting data, and year end trial balance, in the amount of only $-12370. This account is offset by 422709 debit . The reason for the variance is due to a change in the unbilled portion of the account at year end, that
Smart Meter OM&A Variance	1556	$ (3.07)	Immaterial, rounding
Conservation and Demand Management (CDM) Expenditures and Recoveries	1565	$ (0.04)	Immaterial, rounding
CDM Contra	1566	$ 0.08	Immaterial, rounding
RSVA - One-time Wholesale Market Service	1582	$ (1.15)	Immaterial, rounding
Disposition and Recovery of Regulatory Balances[10]	1595	$ 31,574.44	This includes the 1592 balance. This amont was not entered inot the 2.1.7 Filing at year end, and therefore it appears as a variance.

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THIRD PARTY REVIEW AND EVALUATION OF LUI'S CDM PROGRAMS FOR THE PURPOSE OF LRAM AND SSM RECOVERY **4**

RECOVERY OF LOST REVENUE AND SHARED SAVINGS

SUMMARY

In 2010 LUI engaged the services of Burman Energy Consultants Group Inc. (BECGI) to review the LDC's preliminary LRAM and SSM and supporting information and assist in producing finalized calculations and report suitable to support an LRAM and SSM claim as part of its 2011 rates submission.

The results of that review is a report from BECGI which is included in its entirety in this Exhibit including the supporting calculations used to calculate a rate rider which LUI is requesting Board approval to recover over one year. The LRAM amounts proposed for recovery and the calculation of the rate rider is provided in the following table. Note that LUI is not submitting any evidence pertaining to SSM recoveries in this Cost of Service.

Table 10-0 Summary of Requested LRAM Amounts

	LRAM $
OPA Programs	
RESIDENTIAL	$17,097.66
GENERAL SERVICE <50KW	$6,796.82
General Service>50kW to 2,999kW	$2,093.67
GENERAL SERVICE (3,000-4,999kW)	$708.53
	$26,696.67

Table 10-1 LRAM Rate Rider

2012 Test Year - LRAM and SSM Rider

	Amounts		Billing Units (2012)		Rate Riders			Two Year Rate Rider	Three Year Rate Rider	Number of Years to Use	Rate Rider to Use
	LRAM	SSM			LRAM	SSM	Total	Total	Total	(2 or 3)	Total
Rate Class	$	$		Metrics	$/unit (kWh or kW)	$/unit (kWh or kW)	$/unit (kWh or kW)	$/unit (kWh or kW)	$/unit (kWh or kW)		$/unit (kWh or kW)
Residential	17,097.66		73,125,152	kWh	0.0002	0.0000	0.0002	0.0001	0.0001		0.0002
GS < 50 kW	6,796.82		35,160,634	kWh	0.0002	0.0000	0.0002	0.0001	0.0001		0.0002
GS 50-2999	2,093.67		303,629	kW	0.0069	0.0000	0.0069	0.0034	0.0023		0.0069
GS 3000 - 4999	708.53		47,442	kW	0.0149	0.0000	0.0149	0.0075	0.0050		0.0149
Sentinel Lights			218	kW	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000
Street Lighting			3,343	kW	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000
USL			716,623	kWh	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000
0			0	kW	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000
0			0	kW	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000
Total	26,696.67	0.00									

LUI notes that the rate rider requested can be implemented over a one year term, due to the small value and small impact to our rates.

APPENDIX A

THIRD PARTY REVIEW AND EVALUATION OF LUI'S CDM PROGRAMS FOR THE PURPOSE OF LRAM AND SSM RECOVERY

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Lakefront Utilities

LRAM Support

August 29, 2011

Prepared by: Bart Burman, MBA, BA.Sc. P.Eng., President

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Attachment B - LRAM Amounts
Attachment C – LRAM Totals
Attachment D - OPA Assumptions

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1. Introduction

Continuing their participation in OPA province wide CDM programs, Lakefront Utilities has demonstrated leadership and obtained significant energy and peak reductions in the communities they serve. In its prior 2011 rate filing, Lakefront Utilities submitted an LRAM claim for $196,513.82, based on results (input assumptions) validated by the OPA up to the end of 2009, and for combined CDM program efforts undertaken between 2006 and 2009.

With continued success in its CDM activities since the previous claim, Lakefront Utilities has additional lost revenues that need to be addressed as part of its 2012 Cost of Service rate filing with the Ontario Energy Board (OEB).

In accordance with the Ontario Energy Board (OEB) published March 28, 2008 Guidelines for Electricity Distributor Conservation and Demand Management EB-2008-0037 ("CDM Guidelines"), LRAM calculations are required for financial adjustments being claimed. In 2010, finalized 2009, OPA published program evaluations were used for LRAM calculations in Lakefront Utilities' 2011 rate submission since this represented the most current information and basis for input assumptions available at the time.

The LRAM claim made in 2010 did not incorporate energy and peak savings beyond what was attributable to 2009 programs up to the end of 2009. Calculations in this claim continue to utilize persistent 2009 program evaluation results into 2010.

2. Scope

Lakefront Utilities requested that Burman Energy Consultants Group Inc. (Burman Energy) prepare and critically assess an additional LRAM claim for program results to the end of 2010. In lieu of OPA published program evaluation results for 2010, 2009 program results were used as a best representative estimate for 2010 program year results. Adjustments to these estimates may be required to accurately reflect final OPA program evaluation results for 2010 programs.

Burman Energy committed to providing the following:

1. Review available suitability of published Lakefront Utilities data for determining appropriate input assumptions.
2. Prepare and finalize LRAM calculations and assumptions consistent with CDM Guidelines and suitable for inclusion in Lakefront Utilities' 2012 IRM3 application, with supporting details.
3. Produce a report, recommendations, and support related to LRAM assessments/findings.

In performing the above tasks, BECGI's involvement is intended to constitute a third party review as specified in the OEB's CDM Guidelines.

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3. LRAM Principles

The OEB issued GUIDELINES FOR ELECTRICITY DISTRIBUTOR CONSERVATION AND DEMAND MANAGEMENT, EB-2008-0037 were applied to the preparation of this LRAM application.

LRAM was calculated as the product of the demand/energy savings by customer class and the Board-approved variable distribution charge appropriate to each respective class (net of Regulatory Asset Recovery rate riders) for Lakefront Utilities.

The OPA published program evaluation reports were utilized where available in the validation of input assumptions.

4. Process

In calculating LRAM, Burman Energy:

1. Reviewed existing LRAM CDM Guidelines and precedents set through LDC submissions to the OEB, to identify the most prudent course for Lakefront Utilities LRAM.
2. Sought counsel within OEB staff to validate assumptions and processes to complete LRAM submission consistent with other LDC submissions.
3. Reviewed Lakefront Utilities' CDM program results and input assumptions.
4. Verified correct input assumptions were applied in LRAM calculations.
5. Prepared report and recommendations related to LRAM calculations consistent with OEB CDM Guidelines which are in the accompanying documentation.

5. Results

A review of Lakefront Utilities' CDM program supporting data verified that documentation exists to support the use of OPA program evaluations as the basis for LRAM calculations. At the time of this report's preparation, preliminary and final program evaluations for 2010 were unavailable. 2009 results were assumed to be a reasonable proxy for LRAM calculations forecast into 2010. These calculations will be updated once the OPA publishes preliminary and/or final program evaluations. Input assumptions and free ridership rates are identified in Attachment D – OPA Assumptions and Measures

The accompanying table below summarizes the calculated amounts for LRAM for Lakefront Utilities' OPA programs. The calculation of the results, by program and customer class as applicable, are explained in the text below, and detailed in the appended attachment.

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	LRAM $
OPA Programs	
RESIDENTIAL	$17,097.66
GENERAL SERVICE <50KW	$6,796.82
General Service>50kW to 2,999kW	$2,093.67
GENERAL SERVICE (3,000-4,999kW)	$708.53
	$26,696.67

6. Calculation of LRAM

OPA sponsored programs represent lost revenue through their successful implementation and are included in LRAM calculations.

LRAM amounts were identified by rate class consistent with the CDM Guidelines for programs that impacted revenues from 2006 to 2010 for OPA programs. No adjustments were made to incorporate impacts for any kW/kWh reductions assumed in current Board approved load forecasts.

The sum of all program LRAM calculations, including OPA sponsored programs is $26,696.67

Attachment A summarizes load impacts by class and program. Attachment B (Foregone Revenue By Class and Program) summarizes the CDM load impacts by program and rate class and the resultant revenue impacts.

The LRAM amounts arising from CDM programs in each respective rate class are allocated to that class for recovery.

7. Recommendations

Burman Energy recommends the following:

1. LRAM amounts arising from CDM programs in each rate class be allocated to that class for recovery.
2. Prepare adjustments to account for any kW/kWh savings amounts included in current load forecasts.
3. Incorporate impacts of final OPA program evaluation reports into LRAM and rate filing addenda as required.

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4. Rate impacts, proposed rate riders and respective terms to mitigate LRAM recovery be addressed by Lakefront Utilities

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ATTACHMENT A

CDM Load Impacts by Class and Program

	NET		GROSS	
Class	**2010**		**2010**	
Program	**kWh**	**kW**	**kWh**	**kW**
OPA Programs				
Residential				
Secondary Fridge Retirement Pilot	9,429	2.14	10,477	2.37
Cool & Hot Savings Rebate	62,940	48.04	107,390	81.78
Every Kilowatt Counts	312,723	15.47	405,604	19.67
Cool Savings Rebate Program	155,913	101.59	338,820	217.21
Great Refrigerator Roundup	248,075	33.44	503,958	68.94
peaksaver®	1,037	235.17	1,153	261.30
Summer Savings	7,461	9.40	62,172	78.34
Social Housing – Pilot	21,609	2.54	21,609	2.54
Summer Sweepstakes	11,459	4.61	14,770	5.94
Every Kilowatt Counts Power Savings Event	411,313	31.14	1,052,296	80.28
General Service<50kW				
High Performance New Construction	42,134	19.02	60,192	27.18
Power Savings Blitz	704,769	175.55	742,837	184.93
General Service>50kW to 2,999kW				
Electricity Retrofit Incentive Program	970,985	127.98	1,365,334	75.28
Demand Response 1	7,206	164.00	7,206	164.00
Demand Response 2	68,594	111.36	68,594	111.36
Demand Response 3	1,310	159.09	1,310	159.09
Loblaw & York Region Demand Response		27.33		27.33
GENERAL SERVICE (3,000-4,999kW)				
Demand Response 1	10,809	246.00	10,809	246.00
Demand Response 2	102,892	167.04	102,892	167.04
Demand Response 3	1,965	238.63	1,965	238.63
Loblaw & York Region Demand Response		41.00		41.00

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ATTACHMENT B
Foregone Revenue by Class and Program

OPA Programs	2009 kWh or kW	2009 Rate per Unit	2010 Load Unit	2010 kWh or kW	2010 Rate per Unit	2010 Revenue	Total Revenue
Residential							
Secondary Fridge Retirement Pilot	kWh	0.0147	9,429	kWh	0.0133	$ 129.81	
Cool & Hot Savings Rebate	kWh	0.0147	62,940	kWh	0.0133	$ 866.48	
Every Kilowatt Counts	kWh	0.0147	312,723	kWh	0.0133	$ 4,305.16	
Cool Savings Rebate Program	kWh	0.0147	155,913	kWh	0.0133	$ 2,146.41	
Great Refrigerator Roundup	kWh	0.0147	248,075	kWh	0.0133	$ 3,415.16	
peaksaver®	kWh	0.0147	1,037	kWh	0.0133	$ 14.28	
Summer Savings	kWh	0.0147	7,461	kWh	0.0133	$ 102.71	
Social Housing – Pilot	kWh	0.0147	21,609	kWh	0.0133	$ 297.49	
Summer Sweepstakes	kWh	0.0147	11,459	kWh	0.0133	$ 157.76	
Every Kilowatt Counts Power Savings Event	kWh	0.0147	411,313	kWh	0.0133	$ 5,662.41	
							$ 17,097.66
GENERAL SERVICE Less Than 50kW							
High Performance New Construction	kWh	0.0103	42,134	kWh	0.0085	$ 383.42	
Power Savings Blitz	kWh	0.0103	704,769	kWh	0.0085	$ 6,413.40	
							$ 6,796.82
General Service>50kW to 2,999kW							
Electricity Retrofit Incentive Program	kW	4.1355	127.98	kW	3.5044	$ 475.40	
Demand Response 1	kW	4.1355	164.00	kW	3.5044	$ 574.72	
Demand Response 2	kW	4.1355	111.36	kW	3.5044	$ 390.25	
Demand Response 3	kW	4.1355	159.09	kW	3.5044	$ 557.50	
Loblaw & York Region Demand Response	kW	4.1355	27.33	kW	3.5044	$ 95.79	
							$ 2,093.67
GENERAL SERVICE (3,000-4,999kW)							
Demand Response 1	kW	1.5850	246.00	kW	1.0229	$ 251.63	
Demand Response 2	kW	1.5850	167.04	kW	1.0229	$ 170.87	
Demand Response 3	kW	1.5850	238.63	kW	1.0229	$ 244.09	
Loblaw & York Region Demand Response	kW	1.5850	41.00	kW	1.0229	$ 41.94	
							$ 708.53
							$ 26,696.67

ATTACHMENT C
LRAM Totals

	LRAM $
OPA Programs	
RESIDENTIAL	$17,097.66
GENERAL SERVICE <50KW	$6,796.82
General Service>50kW to 2,999kW	$2,093.67
GENERAL SERVICE (3,000-4,999kW)	$708.53
	$26,696.67

Attachment D, which includes Measure Results at End User Level, is attached to the Cost of Service under separate cover, due to size limitations

...\2012 Templates\Attachment A-D - LRAM Application LUSI 2010 OPA Programs - R3.xls