EXHIBIT 4 – OPERATING COSTS

EB-2016-0089

Contents

Overview of Cost Trends

Ex.4/Tab 1/Sch.1 – Overview of Operating Expenses

Operations, Maintenance and Administrative ("OM&A") costs in this application represent Lakefront Utilities Inc.'s ("LUI") integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives, to comply with the Distribution System Code ("DSC"), environmental requirements and Government direction, and to maintain distribution business service quality and reliability at targeted performance levels. These costs represent the reasonably incurred cost to provide services to customers connected to LUI's distribution system, and to meet the service levels stipulated in the Standard Supply Service Code and the Retailer Settlement Codes.

Administration costs for LUI and for Regulatory issues take up a large amount of staff and management time and are a direct cost borne by LUI as set out in the service agreement.

OM&A expenses included in the calculation of a utility's revenue requirement are those determined to be reasonable in amount and necessary for and related to the provision of utility service or in some way benefit customers. OM&A expenses consist of; the required expenditures necessary to maintain and operate LUI's distribution system assets; the costs associated with metering, billing, collecting from its customers; the costs associated with ensuring all stakeholders safety; and costs to maintain the distribution business service quality and reliability.

As required in the Affiliate Relationship Code ("ARC"), LUI has one third of its Board of Directors as an independent director.

An inflation rate of 1.95% for 2016 and 2017 was used where the expense increase could not be specifically identified. The inflation rate is consistent with the OEB-approved parameter for inflation.

As shown in Table 4.0 below, LUI's decrease in OM&A spending from its 2012 Cost of Service ("COS") to the 2017 Test Year amounts to $144,931 or 5.64% less over the last 6 years.

Table 4.0: 2017 vs. 2012 Board Approved

Reporting Basis	2012 Board Approved	2017	Variance from Board Approved
Operations	724,871	525,404	(199,467)
Maintenance	322,942	195,787	(127,156)
Billing and Collecting	412,387	566,316	153,929
Community Relations	6,824	20,219	13,395
Administrative and General (including LEAP)	1,102,146	1,116,514	14,368
Total OM&A Expenses	**2,569,170**	**2,424,239**	**(144,931)**
Percent Change		**-5.64%**	

The following is an explanation of the significant fluctuations:

- The majority of the decrease in operations can be attributed to a decrease in Operation Supervision and Engineering (account 5005) of $194,467 as a result of the retirement of the Manager of Electric Distribution.

  There was also a decrease in Overhead Distribution Lines and Feeders (accounts 5020 and 5025) of $118,252. Although an overall decrease, primarily driven by retirements and an increase in capital work, the balance was also increased to account for a portion of the wages related to a new lineman.

  The above decrease have been offset by an increase in Distribution Station Equipment (accounts 5016 and 5017) of $27,224 as a result of annual maintenance associated with weed control, an infrared survey, station maintenance, station transformer oil tests and station inspections. Furthermore, there is an increase in Underground Distribution Lines and Feeders (account 5040 and 5045) of $76,585 related to the costs associated with outsourcing locates.

- The decrease in maintenance costs is the result of a decrease in Maintenance of Meters (account 5175) of $127,156. The decrease in meter maintenance is partially the result of a retirement and also the result of an allocation of metering costs to account 5310 (meter reading expense) in Billing and Collecting. The decrease was partially offset by inflationary increases in payments to ERTH for metering costs. Furthermore, there was a decrease in Maintenance of Poles, Towers, and Fixtures (account 5120) of $34,444 and Maintenance of Overhead Conductors and Devices (account 5125) of $8,243 as a result of the increased capital work.

  The above decreases have been offset by an increase in Maintenance of Overhead Services (account 5130) and Overhead Distribution Lines and Feeders – Right of Way (account 5135) of $120,753. The increase is a result of an increase in maintenance associated with system inspections, load break switch maintenance and tree trimming.

- The increase in Billing and Collecting of $153,929 is the result of an increase in Meter Reading Expenses (account 5310) of $245,034. This increase is a result of a reallocation of meter reading expenses from Maintenance of Meters (account 5175) to Meter Reading Expenses (account 5310). The expenses consist of payments to Savage Data Systems Ltd, Utilismart Corporation, and Sensus (metering data services provider).

  The above increase was offset by a decrease in Customer Billing and Collecting (account 5315 and 5320) of $45,663 as a result of the retirement of two Customer Service Representatives. Furthermore, there was a decrease of $102,821 related to Miscellaneous Customer Accounts

Expenses (account 5340). The decrease is the result of a decrease in expenses associated with our billing application service provider, ERTH and Ecaliber.

- Community relations consists of expenses related to various customer engagement activities such as scholarships, customer information sessions, preparation of an annual report, and promotion/advertising.

The variance used to determine the OM&A accounts requiring analysis as described by the Filing Requirements issued July 16, 2015 is $50,000 for a distributor with revenue less than or equal to $10 million. LUI will provide analysis for all variances greater than $50,000 for OM&A.

OEB Appendix 2-JA below shows a summary of Lakefront Utilities Inc. Operations, Maintenance and Administrative ("OM&A") costs as required by the OEB's filing guidelines.

Appendix 2-JA: Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013	2014	2015	2016	2017
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations	$724,871	$553,856	$658,284	$596,391	$508,337	$510,101	$525,404
Maintenance	$322,942	$135,286	$239,277	$219,341	$175,003	$190,084	$195,787
SubTotal	**$1,047,813**	**$689,143**	**$897,562**	**$815,732**	**$683,340**	**$700,185**	**$721,191**
%Change (year over year)			30.2%	-9.1%	-16.2%	2.5%	3.0%
%Change (Test Year vs Last Rebasing Year - Actual)							-31.2%
Billing and Collecting	$412,387	$597,740	$574,811	$618,225	$531,136	$549,821	$566,316
Community Relations	$6,824	$12,330	$12,931	$11,089	$12,773	$19,630	$20,219
Administrative and General+LEAP	$1,102,146	$996,623	$1,104,834	$1,056,532	$1,043,672	$1,132,287	$1,116,514
SubTotal	**$1,521,357**	**$1,606,693**	**$1,692,576**	**$1,685,846**	**$1,587,580**	**$1,701,738**	**$1,703,048**
%Change (year over year)			5.3%	-0.4%	-5.8%	7.2%	0.1%
%Change (Test Year vs Last Rebasing Year - Actual)							6.0%
Total	**$2,569,170**	**$2,295,835**	**$2,590,137**	**$2,501,578**	**$2,270,920**	**$2,401,923**	**$2,424,239**
%Change (year over year)			12.8%	-3.4%	-9.2%	5.8%	0.9%

As detailed in Appendix 2-JA, LUI's Operations and Maintenance expenses have decreased from the 2012 Board Approved amounts. Although the expenses decreased, LUI's reliability statistics (SAIDI and SAIFI) have also decreased from 2012 and remain well below the industry average.

Furthermore, as detailed below, the decrease in Operations and Maintenance is the result of numerous retirements.

Employee Flowchart

Position	2012	2013	2014	2015	2016	2017
President	🟦	🟦	🟦	🟦	🟦	🟦
VP of Operations	🟦	🟦	🟦	🟦	🟦	🟦
IT Manager	🟦	🟨	⬜	⬜	⬜	⬜
Manager of Electric Distribution	🟦	🟦	🟦	🟪	⬜	⬜
Manager of Electric Distribution	⬜	🟩	🟦	🟦	🟦	🟦
Electric Distribution Supervisor	🟦	🟦	🟦	🟦	🟦	🟦
Journeyman Lineman	🟦	🟦	🟦	🟦	🟦	🟦
Journeyman Lineman	🟦	🟦	🟦	🟦	🟦	🟦
Journeyman Lineman	🟦	🟦	🟦	🟦	🟦	🟦
Journeyman Lineman	🟩	🟧	⬜	⬜	⬜	⬜
Journeyman Lineman	🟦	🟨	⬜	⬜	⬜	⬜
Journeyman Lineman	⬜	🟩	🟦	🟦	🟦	🟦
Journeyman Lineman	⬜	🟩	🟦	🟦	🟦	🟦
Journeyman Lineman	⬜	⬜	⬜	⬜	🟩	🟦
Distribution Technician	🟦	🟦	🟪	🟩	🟦	🟦
Distribution Technician	🟦	🟦	🟦	🟪	⬜	⬜
Distribution Technician	🟦	🟦	🟦	🟦	🟦	🟦
Distribution Technician	🟦	🟦	🟦	🟪	⬜	⬜
Director of HR/Executive Assistant	🟦	🟦	🟦	🟪	⬜	⬜
HR Generalist	🟦	🟦	🟦	🟦	🟦	🟦
Safety and Training Coordinator	🟦	🟦	🟦	🟪	⬜	⬜
Customer Service Supervisor	🟦	🟦	🟦	🟦	🟦	🟦
Customer Service Representative	🟦	🟦	🟦	🟦	🟦	🟦
Customer Service Representative	🟦	🟦	🟦	🟪	⬜	⬜
Customer Service Representative	🟦	🟦	🟦	🟪	🟩	⬜
Customer Service Representative	🟦	🟦	🟦	🟦	🟦	🟦
Customer Service Representative	🟦	🟦	🟦	🟦	🟦	🟦
CDM/Key Account Representative	⬜	⬜	⬜	🟩	🟦	🟦
Director of Regulatory and Finance	🟦	🟦	🟨	⬜	⬜	⬜
Senior Financial Analyst	🟦	🟧	⬜	⬜	⬜	⬜
Finance Supervisor	⬜	🟩	🟦	🟦	🟦	🟦
Finance Assistant	🟦	🟦	🟦	🟦	🟦	🟦
Finance Assistant	⬜	⬜	🟩	🟦	🟦	🟦
Regulatory and Financial Analyst	🟦	🟦	🟦	🟧	⬜	⬜
Regulatory and Financial Analyst	⬜	⬜	⬜	🟩	🟦	🟦
Field Services Rep/Stores	🟦	🟦	🟦	🟪	⬜	⬜

🟦	Current Employee
🟩	Hired
🟧	Resigned
🟪	Retired
🟨	Terminated
⬜	N/A

Summary of Cost Driver Tables

Ex.4/Tab 2/Sch.1 – Cost Driver Tables

In accordance with the OEB's minimum filing requirements, OEB Appendix 2-JB below outlines the key drivers of OM&A costs over the 2012 to 2017 period. The following pages are the explanations of year over year cost drivers. LUI will provide analysis for all variances greater than $50,000.

Operations and Maintenance expenses include all costs relating to the operation and maintenance of the LUI distribution system which are necessary in order to keep the distribution system in a state of good repair. The work typically involves inspection, testing, cleaning, and verification activities. This includes both direct labour costs and non-capital material spending to support both scheduled and reactive maintenance events.

LUI strives to provide safe, reliable service while minimizing the life cycle costs of assets by doing predictive and preventative work. Maintenance work also helps to identify those areas that require capital investments. LUI is then able to adjust its capital spending priorities to address these matters.

LUI places a high priority on the upkeep and replacement of its aging infrastructure. Asset management leads to increases in operational costs. Distribution equipment that was placed in-service 40 years ago, in many cases, has reached its normal useful life. Therefore LUI is faced with the ongoing replacement of this aging infrastructure that originated in those early years when growth accelerated. Customer expectations for reliability have increased over time and as new technology is added to the system it can only perform on a solid base of well-maintained distribution infrastructure. Thus, investment in replacement equipment along with its associated operational costs has become a continuous reality for LUI as it commits to satisfying the essential community needs.

OEB Appendix 2-JB – Recoverable OM&A Cost Driver Table

OM&A	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance	$ 2,569,170	$ 2,295,835	$ 2,590,137	$ 2,501,577	$ 2,270,920	$ 2,401,922
Operation and supervision wages	($113,193)				($29,625)	
Overhead conductor labour as a result of increased capital	($82,539)		($91,816)			
Overhead distribution labour - less capital work		$79,341				
Overhead materials and supplies			($12,855)			
Tree trimming	($20,895)	$14,459		($4,489)		
Transformer maintenance		$12,607				
Distribution station maintenance		($16,156)	($10,211)			
Technical services technician not hired until 2015	($52,313)					
Billing expenses	($27,642)					
Meter reading	$212,943		($49,637)			
Meter maintenance	($117,038)		($15,186)	($28,034)		
Outside services	($102,316)					
Underground locates, including third party costs		$67,129				
Overhead maintenance - less capital work		$55,931				
IT services		$95,015	($55,725)			
Office supplies		($12,567)				
New manager of electric distribution - succession planning			$61,041			
Retirment of previous electric distribution manager				($90,748)		
Third party service provide - accounting software assistance			($29,595)			
Bad debts			$107,044			
Retirement of distribution technicians				($44,338)		
Retirement of customer service staff				($87,089)		
Overhead disribution lines and feeders - ROW					$60,928	$14,421
Regulatory costs					$21,702	
Community relations					$6,857	$589
Outside service - IT audit, IFRS conversion					$84,639	
Customer service - new staff hire						$16,205
Miscellaneous remaining balance	$29,658	($1,457)	$8,380	$24,041	($13,499)	($8,898)
Closing Balance	$ 2,295,835	$ 2,590,137	$ 2,501,577	$ 2,270,920	$ 2,401,922	$ 2,424,239

Ex.4/Tab 2/Sch.2 – OM&A Variance Analysis

Table 4.1 shows the year over year variances of OM&A expenses from the 2012 Board Approved to the 2017 Test Year. A variance analysis of expenses exceeding materiality threshold of $50,000 follows the table.

Table 4.1: Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013	2014	2015	2016	2017
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations	$724,871	$553,856	$658,284	$596,391	$508,337	$510,101	$525,404
Maintenance	$322,942	$135,286	$239,277	$219,341	$175,003	$190,084	$195,787
SubTotal	**$1,047,813**	**$689,143**	**$897,562**	**$815,732**	**$683,340**	**$700,185**	**$721,191**
%Change (year over year)			30.2%	-9.1%	-16.2%	2.5%	3.0%
%Change (Test Year vs Last Rebasing Year - Actual)							-31.2%
Billing and Collecting	$412,387	$597,740	$574,811	$618,225	$531,136	$549,821	$566,316
Community Relations	$6,824	$12,330	$12,931	$11,089	$12,773	$19,630	$20,219
Administrative and General+LEAP	$1,102,146	$996,623	$1,104,834	$1,056,532	$1,043,672	$1,132,287	$1,116,514
SubTotal	**$1,521,357**	**$1,606,693**	**$1,692,576**	**$1,685,846**	**$1,587,580**	**$1,701,738**	**$1,703,048**
%Change (year over year)			5.3%	-0.4%	-5.8%	7.2%	0.1%
%Change (Test Year vs Last Rebasing Year - Actual)							6.0%
Total	**$2,569,170**	**$2,295,835**	**$2,590,137**	**$2,501,578**	**$2,270,920**	**$2,401,923**	**$2,424,239**
%Change (year over year)			12.8%	-3.4%	-9.2%	5.8%	0.9%

Table 4.2: 2012 Actual vs. 2012 Board Approved

Reporting Basis	**2012 Board Approved**	**2012**	**Variance from Board Approved**
Operations	724,871	553,856	(171,014)
Maintenance	322,942	135,286	(187,656)
Billing and Collecting	412,387	597,740	185,353
Community Relations	6,824	12,330	5,506
Administrative and General (including LEAP)	1,102,146	996,623	(105,523)
Total OM&A Expenses	**2,569,170**	**2,295,835**	**(273,335)**
Percent Change		**-10.64%**	

2012 Board Approved vs. 2012 Actual

The total OM&A expenses in 2012 are $273,335 or 10.64% less than the 2012 Board Approved amount. The main reason for the variances are:

1) A decease in operations of $171,014 is mainly attributable to a decrease of $113,193 as a result of the delay in hiring a replacement for the Manager of Electric Distribution. In the 2012 Cost of

Service, LUI applied for increase in costs to manage succession planning and the addition of another Manager of Electric Distribution, related to attrition issues.

Operation expenses also decreased as a result of a decrease of $82,538 associated with the allocation of labour to capital work on overhead conductors and devices (account 1835).

2) A decrease in maintenance costs of $187,656, is the result of a decrease of $52,313 in maintenance wages. LUI planned on hiring a technical service technician, however, the technician was not hired until 2015, and at that time, the technician's costs were allocated to various capital jobs and projects that are identifiable and directly associated to existing APH accounts.

   Additional decrease is the result of meter maintenance costs of $117,038. The Board Approved amount was to be recorded in account 5175. Lakefront recorded the majority of the meter maintenance costs in account 5310, which is grouped with Billing and Collecting.

   Remaining decrease is related to decrease of $41,787 in poles, towers and fixtures maintenance and $20,892 increase related to tree trimming maintenance.

3) Increase in Billing and Collecting of $185,353 is the result of increase in meter reading expenses of $212,943. As discussed above, the majority of Board Approved meter reading costs were approved for account 5175, however, LUI recorded the expenses in 5310.

   Increase associated with meter reading expenses was offset by decrease of $27,642 in customer billing expenses.

4) Decrease in administration and general expenses of $105,523 is primarily the result of a decrease in outside services of $102,316. LUI had planned for significant expenses associated with the IFRS transition in 2012, which was later deferred until 2016.

Table 4.3: 2013 Actual vs. 2012 Actual

Reporting Basis	2012	2013	Variance
Operations	553,856	658,284	104,428
Maintenance	135,286	239,277	103,991
Billing and Collecting	597,740	574,811	(22,929)
Community Relations	12,330	12,931	601
Administrative and General (including LEAP)	996,623	1,104,834	108,211
Total OM&A Expenses	**2,295,835**	**2,590,137**	**294,302**
Percent Change		**12.82%**	

2013 Actual vs. 2012 Actual

The total OM&A expenses in 2013 are $294,302 or 12.82% greater than the 2012 actual amount. The main reason for the variances are:

1) An increase in operations expenses of $104,428, attributable to an increase of $79,341 in overhead distribution labour as a result of a decrease in capital work. As detailed in Exhibit #2, LUI spent $889,568 in capital work ($28,363 net of amortization), a significant decrease from LUI's average capital of $1,612,834 between 2012 and 2015.

   Furthermore, LUI had an increase in account 5040 – locates of $67,129. Increases were offset by slight decreases in distribution station maintenance ($16,156) and transformer maintenance ($11,681).

2) Increase in maintenance of $103,991 is due to an increase of $55,931 in overhead maintenance, as a result of a decrease in capital work and increases in tree trimming ($14,459) and transformer maintenance ($24,288).

3) Administration and general increased by $108,211 as a result of an increase of $95,015 in IT costs. LUI terminated a full time staff employment in 2013 that was dedicated to IT and hired a subcontractor. As a result, IT expenses in 2013 include a portion of IT staff wages and subcontractor fees.

Table 4.4: 2014 Actual vs. 2013 Actual

Reporting Basis	2013	2014	Variance
Operations	658,284	596,391	(61,894)
Maintenance	239,277	219,341	(19,936)
Billing and Collecting	574,811	618,225	43,414
Community Relations	12,931	11,089	(1,841)
Administrative and General (including LEAP)	1,104,834	1,056,532	(48,302)
Total OM&A Expenses	**2,590,137**	**2,501,578**	**(88,560)**
Percent Change		**-3.42%**	

2014 Actual vs. 2013 Actual

The total OM&A expenses in 2014 are $88,560 or 3.42% less than the 2013 amount. The main reason for the variances are:

1) Overall decrease in operations of $61,894 is the net of an increase in operation supervision and engineering (account 5005) of $64,041 as LUI hired a Manager of Electric Distribution as approved in the 2012 Cost of Service, to assist with succession planning and the retirement of the previous Distribution Manager.

   Furthermore, there was a decrease in overhead distribution (account 5020) of $91,816 as a result of an increase in capital work. There was also slight decreases in various supplies ($12,855) and labour related to distribution stations ($10,211).

2) Increase in billing and collecting of $43,414 is due to an increase of $107,044 in bad debts as a result of an increase in customers paying late (which caused an increase in allowance for doubtful accounts at year end) and the fact that LUI had previously not been consistent with writing off bad debts.

   The increase in bad debts was offset by decrease in meter reading costs of $49,637.

Table 4.5: 2015 Actual vs. 2014 Actual

Reporting Basis	2014	2015	Variance
Operations	596,391	508,337	(88,053)
Maintenance	219,341	175,003	(44,338)
Billing and Collecting	618,225	531,136	(87,089)
Community Relations	11,089	12,773	1,684
Administrative and General (including LEAP)	1,056,532	1,043,672	(12,861)
Total OM&A Expenses	**2,501,578**	**2,270,920**	**(230,658)**
Percent Change		**-9.22%**	

2015 Actual vs. 2014 Actual

The total OM&A expenses in 2015 are $230,658 or 9.22% less than the 2014 amount. The main reason for the variances are:

1) Decrease in operations expenses of $88,053 is the result of a decrease in operation supervision and engineering (account 5005) of $90,748 as a result of the retirement of the Manager of Electric Distribution.

2) Maintenance expenses decreased by $44,338 as a result of a decreases in overhead maintenance ($2,990) and underground maintenance ($1,499) as a result of increased capital work. As detailed in Exhibit #2, LUI's capital work in 2015 was $1,780,581 compared to $1,430,104 in 2014.

   Furthermore, there was a decrease in meter maintenance of $28,034, primarily the result of the retirement of two distribution technicians.

3) Decrease in billing and collecting expenses of $87,089 is a result of the retirement of two Customer Service Representatives and a decrease in bad debts of $107,044 as 2014 bad debts were irregularly high.

Table 4.6: 2016 Bridge Year vs. 2015 Actual

Reporting Basis	2015	2016	Variance
Operations	508,337	510,101	1,764
Maintenance	175,003	190,084	15,081
Billing and Collecting	531,136	549,821	18,685
Community Relations	12,773	19,630	6,857
Administrative and General (including LEAP)	1,043,672	1,132,287	88,615
Total OM&A Expenses	**2,270,920**	**2,401,923**	**131,003**
Percent Change		**5.77%**	

2016 Bridge Year vs. 2015 Actual

The total OM&A expenses in the 2016 Bridge Year are $131,003 or 5.77% greater than the 2015 amount. The main reason for the variances are:

1) Maintenance expenses increased by $15,081 from 2015. The increase is primarily the result of an increase in Maintenance of Overhead Services and Overhead Distribution Lines and Feeders – Right of Way (accounts 5130 and 5135) of $60,928 and the result of expense related to system inspections, tree trimming, and load break switch maintenance.

2) Billing and Collecting expenses increased slightly by $18,685 from 2015 as a result of decrease in customer billing (account 5315) of $26,708 and customer collecting (account 5320) of $12,075 due to the retirement of two Customer Service Representatives ("CSR") in 2015. The decreases were offset by the replacement of one CSR and inflationary increases in meter reading expenses (account 5310) and miscellaneous customer accounts expenses (account 5340).

3) Community Relations expenses increased by $6,857 as a result of $1,750 related to the preparation of an annual report, $1,200 related to customer information sessions and the balance for other events.

4) Administrative and General expenses have increased by $88,615 from 2015. The increase is a result of an increase in Outside Services Employed (account 5630) of $67,110 as a result of $30,000 budgeted for an IT audit and an increase of $15,000 budget for costs associated with transitioning to IFRS.

   Furthermore, there is an increase of $21,702 in regulatory costs as a result of the costs associated with the 2017 Cost of Service, which have been amortized over a five year period. The remaining increase is the result of inflationary increase on wages.

Table 4.7: 2017 Test Year vs. 2016 Bridge Year

Reporting Basis	2016	2017	Variance
Operations	510,101	525,404	15,303
Maintenance	190,084	195,787	5,703
Billing and Collecting	549,821	566,316	16,495
Community Relations	19,630	20,219	589
Administrative and General (including LEAP)	1,132,287	1,116,514	(15,773)
Total OM&A Expenses	**2,401,923**	**2,424,239**	**22,316**
Percent Change		**0.93%**	

2017 Test Year vs 2016 Bridge Year

Between the 2017 Test year to the 2016 Bridge Year there are no significant material variances.

There is no effect on LUI's OM&A expenses due to changes in capitalization as burdens have not been capitalized by LUI. Therefore, Appendix 2-D is not applicable.

OEB Appendix 2-L Recoverable OM&A Cost per Customer and per FTE, outlines the cost per customer per full time employee. This information is provided for the 2012 to 2017 period, in accordance with the OEB's minimum filing requirements, discussions of cost per customer follows the Appendix.

OEB Appendix 2-L: Recoverable OM&A Cost per Customer and per FTE

	Last Rebasing Year - 2012 - Board Approved	Last Rebasing Year - 2012 - Actual	2013 Actuals	2014 Actual	2015 Actuals	2016 Bridge Year	2017 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Number of Customers	12,767	12,681	12,837	12,749	12,936	13,086	13,239
Total Recoverable OM&A from Appendix 2-JB	2,569,170	2,295,835	2,590,137	2,501,578	2,270,920	2,401,923	2,424,239
OM&A cost per customer	201.24	181.05	201.77	196.22	175.56	183.55	183.11
Number of FTEs	22.20	20.22	19.75	20.82	16.83	18.50	18.50
Customers/FTEs	575.09	627.13	649.97	612.34	768.60	707.36	715.62
OM&A Cost per FTE	115,728	113,543	131,146	120,153	134,933	129,834	131,040

As shown in the OEB appendix above, the OM&A cost per customer in the Test Year has decreased by approximately $18 per customer since the 2012 Board Approved costs. According to the 2014 Yearbook of Electricity Distributors released July 31, 2015, LUI's 2014 OM&A cost per customer is well below the provincial average of $339.

Program Delivery Costs with Variance Analysis

Ex.4/Tab 3/Sch.1 – Program Description

The following section describes programs which Lakefront Utilities Inc. is adopting. The categorization of USoA account/functions has been based on the RRFE categories: Customer Focus, Operational Effectiveness and Public & Regulatory Responsiveness.

Program Overview

LUI aims to meet or exceed the system maintenance and inspection requirements of the DSC in order to minimize subsequent repair and/or replacement costs. Section 4.4.1, of the DSC states:

> "A distributor shall maintain its distribution system in accordance with good utility practice and performance standards to ensure reliability and quality of electricity service, on both a short-term and long-term basis."

The following OM&A programs are consistent with good utility practices.

Customer Focus

- Community Relations
- Billing, Collecting, Customer Service
- Bad Debts and Collections

Operational Effectiveness

- Meter Maintenance and Readings
- Overhead Maintenance
- Underground Maintenance
- Engineering
- Distribution Station Maintenance
- Transformer Maintenance
- Vegetation Management
- Building Maintenance
- Administration and Financial

Public and Regulatory Responsiveness

- Insurance
- Regulatory Compliance
- Professional fees and dues

- Office supplies and telecommunications

Each program is discussed further below.

CUSTOMER FOCUS

Community Relations

The organizational effectiveness and communications programs involves developing and maintaining effective employee, customer and shareholder relations. It also involves organizational development, and reaching out to customers in many forms, such as social media and online communication.

Billing, Collecting & Customer Service

LUI's billing staff are responsible for all billing activities supporting all customers in LUI's service territory. This includes monthly billing that results in Lakefront Utilities Inc. issuing over 100,000 bills annually in addition to approximately 2,000 final bills for customers moving within or outside of Lakefront's service territory. The billing department is responsible for managing Electronic Business Transactions ("EBT") and retailer settlement functions for just over 500 retailer accounts; account adjustments; processing of meter change (e.g. re-verification); and other various account related field service orders, and mailing services. In 2015 LUI produced over 84,000 bills with a billing accuracy of 100%.

LUI offers customers a number of billing and payment options including an electronic bill, pre-authorized payments, equal payment plan, and credit card payments. In addition, customers can view their usage and manage their consumption using an online application.

Collection activity is not exclusive to overdue accounts; it also includes the adoption and continued application of the Customer Service Amendments consistent with the OEB's DSC. The department is also responsible for the activation and reconciliation of the equal payment program and processing payments.

LUI endeavours to maintain an early collections process to minimize the number of accounts that near the disconnection stage. Active accounts are collected through phone calls, notices, and hand delivered letters.

The Customer Service staff are responsible for handling day to day customer inquiries in regards to their accounts and fielding numerous other questions as they relate to Government and Regulatory policy, conservation and demand management, pricing and consumption inquiries. In addition to this function, CSR's are also responsible for processing of payments dropped off at our office, going to the post office and processing those payments, responding to emails, and numerous other administrative tasks.

As the number of electricity end users in our service area increases and changes occur within Ontario's electricity market, LUI's call and correspondence volumes will continue to increase.

Bad Debt and Collections

Unfortunately bad debt costs are the nature of any business. However, due to the stringent requirements for the treatment of low income customers, more focus is needed by the customer service staff to assist this group of customers. Overdue final accounts are assigned to a collection agency after being approved at the quarterly board meetings. LUI is now experiencing an increase in its bad debt expense that is attributed to an overall decline in the economy, increased rates and in 2014 a colder winter that increased consumption for electric heating customers.

OPERATIONAL EFFECTIVENESS

Meter Maintenance and Reading

This department is responsible for the installation, testing, and commissioning of new metering and for the ongoing operations of existing metering, both simple and complex metering installations. Testing of complex metering installations ensures the accuracy of the installation (e.g. to verify that the appropriate meter multipliers are applied through the billing process). Metering will also investigate potential stopped meters, diversion and/or theft of power which may give rise to unsafe conditions or cause other customers to be inappropriately held financially responsible for overall costs. The metering group benefits customers in two ways:

1. The ongoing accurate operation of meters provides real time operating data to SCADA and other systems that supports Systems Operations.

2. Ensuring that bills are computed correctly, therefore ensuring that customers are fairly charged for the services provided.

Overhead and Underground Maintenance

LUI's strategy is to provide safe, reliable service at an appropriate level of quality and price throughout the license service area. LUI's maintenance strategy is an important part of its overall strategy of minimizing the life cycle costs of assets by minimizing reactive and emergency-type work, through planned maintenance programs (including predictive and preventative actions). These strategies are implemented through work practices that promote a good experience for the customer with regard to safety, security of supply, reliable continuity of service, the timely restoration of service and the minimization of undesirable service conditions. LUI's customers receive high quality services and customers see that the system is in a state of good repair, that crews are engaged in inspection, testing, cleaning, and verification activities. Increasingly, however, LUI's assets and services are less visible – underground conductors encased in conduits, Smart Meters that do not need to be read manually and, system monitoring (e.g. for voltage sag, line balancing, to ensure backup can be realized) via electronic devices that communicate wirelessly and provide real time analysis that has less of an impact on customers.

LUI's underground and overhead maintenance expenses include all costs relating to the operation and maintenance of LUI's distribution 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 burdens. LUIs existing overhead plant is for the most part over 40 years old and will require increased maintenance costs until it can be replaced as part of the capital asset plan.

Engineering

LUI provides Offers to Connect requests from developers for the design and installation of distribution plant for projects that require expansion to LUI's system. LUI must also maintain the collection, analysis and allocation of materials, and labour for the overall system planning coordination and management of the distribution system design, through construction activities to enhance, modify and renew the distribution system.

LUI monitors its distribution station transformers and feeders through a Supervisory Control and Data Acquisition (SCADA) system. Real-time breaker status, voltage and current readings from the seven stations are on display in the engineering office. The SCADA system can also coordinate field work to establish and preserve work protection and safe conditions for the crews doing work on the system.

Distribution Station Maintenance and Transformer Maintenance

LUI owns and operates seven distribution station transformers, with five in Cobourg and two in Colborne. Beginning in 2012, LUI invested in a SCADA system at its seven stations and LUI utilizes the services of Utilismart to provide remote meter readings to some of its stations. This assists in more accurate and timely station and feeder loading models. Additionally, LUI implemented GIS to assist in mapping assets, and improving data input for increased system optimization.

LUI maintenance consists of completing visual inspections as per the OEB's DSC requirements 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.

Vegetation Management (Tree Trimming)

Tree trimming is a critical element of the overall maintenance program that brings measureable results to the utility. LUI's service territory is heavily treed and there is the potential for unplanned outages that are caused by tree contact; therefore regular vegetation management is required. LUI's regular vegetation management is based on a regular cyclical geographical based schedule as well as input from routine inspections. Vegetation is managed to ensure there is adequate clearance between the line and any trees or other vegetation that could interfere with the operation of the power system.

To manage the tree trimming activities requirement for LUI, an outside contractor is used.

Building Maintenance

Building maintenance expenditures are required for the repair maintenance and upkeep of LUI's administration building and garage facility. LUI's administrative building is over 85 years old and classified as a heritage building in Cobourg. Regular maintenance is conducive to its safe, ergonomically suitable upkeep.

Administration and Financial

The program includes administrative/financial costs incurred annually as part of the utility's business operations. These costs also include general accounting, policy development and human resources. This program covers preparation of statutory, management and financial report; accounts payable and general accounting; treasury functions, including borrowing and cash management; financial risk management; accounting systems and internal control processes; preparation of consolidated budgets and forecasts; and tax compliance.

PUBLIC AND REGULATORY COMPLIANCE

Insurance

This program includes costs for executive insurance, liability insurance and property insurance required to protect LUI in its daily operations.

Regulatory Compliance

These program costs are related to LUI's commitment to comply with Ontario's evolving energy market, changing government policy and evolving regulatory framework. The increased complexity in the regulatory environment, such as RRFE, Distribution System Plan, all can increase spending. LUI constantly searches ways to minimize costs and improve efficiencies through collaboration, whether it is with CHEC or neighboring utilities - purchasing groups, we are always seeking economies of scale and scope opportunities.

Professional Fees and Dues

The program includes costs such as auditor, outside consultants and legal costs incurred annually as part of the utility's business operations. The program covers preparation of audited financial statements, legal costs for preparation of documents or advice for LUI's tax filing.

Office Supplies and Telecommunications

This program includes the monthly costs of phone service, fibre services, postage, bill print paper, etc. The expense also includes the costs of an after-hours service to ensure that operations respond to emergencies in a timely manner.

Ex.4/Tab 3/Sch.2 – Program Variance Analysis

Appendix 2-JC shows LUI's OM&A programs and Table 4.8 shows the year over year variances of OM&A programs for 2012 Board Approved to the 2017 Test Year. A variance analysis of expenses exceeding the materiality threshold follows the table.

OEB Appendix 2-JC: OM&A Programs Table

Programs	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year	Variance (Test Year vs. 2015 Actuals)	Variance (Test Year vs Last Rebasing Year - 2012 Board Approved)
Reporting Basis	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	CGAAP
Customer Focus									
Community Relations	$11,824	$17,330	$18,331	$16,390	$18,074	$24,931	$26,069	$7,995	$14,245
Billing, Collecting, & Customer Service	$272,247	$226,672	$238,989	$269,073	$215,759	$252,023	$259,584	$43,825	($12,664)
Bad Debts and Collections	$125,968	$75,933	$114,330	$177,296	$54,964	$46,143	$47,527	($7,437)	($78,441)
Sub-Total	$410,040	$319,934	$371,649	$462,759	$288,797	$323,097	$333,180	$44,383	($76,860)
Operational Effectiveness									
Meter Maintenance & Readings	$200,113	$362,653	$304,014	$239,192	$299,715	$292,744	$301,526	$1,812	$101,414
Overhead Maintenance	$404,724	$243,798	$370,714	$279,123	$288,009	$319,989	$329,589	$41,579	($75,135)
Underground Maintenance	$44,645	$48,443	$125,622	$125,491	$137,460	$144,497	$148,832	$11,372	$104,187
Engineering	$309,923	$162,528	$121,462	$201,117	$99,345	$69,720	$71,812	($27,534)	($238,111)
Distribution Station Maintenance	$35,133	$95,013	$98,332	$86,319	$63,805	$66,446	$68,439	$4,634	$33,306
Transformer Maintenance	$30,309	$47,681	$60,288	$34,723	$9,997	$11,619	$11,968	$1,971	($18,341)
Vegetation Maintenance	$37,137	$24,162	$38,622	$21,623	$45,421	$46,825	$48,230	$2,809	$11,093
Building Maintenance	$69,546	$38,485	$54,655	$61,316	$55,770	$59,812	$61,606	$5,836	($7,939)
Administrative and Financial	$608,037	$547,236	$655,255	$596,638	$630,501	$617,762	$635,652	$5,151	$27,615
Sub-Total	$1,739,566	$1,569,999	$1,828,964	$1,645,541	$1,630,024	$1,629,414	$1,677,654	$47,630	($61,913)
Public and Regulatory Responsiveness									
Insurance	$75,084	$78,054	$77,687	$91,850	$62,136	$62,941	$64,829	$2,693	($10,255)
Regulatory Compliance	$85,364	$115,667	$40,476	$78,889	$39,238	$66,940	$63,299	$24,061	($22,065)
Professional Fees & Dues	$167,289	$110,191	$172,662	$120,861	$157,587	$225,997	$188,937	$31,350	$21,648
Office Supplies & Telecommunications	$91,826	$101,991	$98,700	$101,677	$93,139	$93,534	$96,340	$3,201	$4,514
Sub-Total	$419,563	$405,902	$389,525	$393,277	$352,100	$449,412	$413,405	$61,306	($6,158)
Total OM&A	**$2,569,170**	**$2,295,835**	**$2,590,137**	**$2,501,578**	**$2,270,920**	**$2,401,923**	**$2,424,239**	**$153,319**	**($144,931)**

Table 4.8: OM&A Program Variances

Programs	2012 vs 2012 BA	2013 vs 2012	2014 vs 2013	2015 vs 2014	2016 vs 2015	2017 vs 2016
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP/MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Customer Focus						
Community Relations	$5,505	$1,001	($1,940)	$1,684	$6,857	$1,138
Billing, Collecting, & Customer Service	($45,576)	$12,317	$30,084	($53,315)	$36,264	$7,561
Bad Debts and Collections	($50,036)	$38,397	$62,966	($122,332)	($8,821)	$1,384
Sub-Total	($90,106)	$51,715	$91,110	($173,963)	$34,301	$10,083
Operational Effectiveness						
Meter Maintenance & Readings	$162,540	($58,638)	($64,823)	$60,523	($6,971)	$8,782
Overhead Maintenance	($160,926)	$126,916	($91,591)	$8,886	$31,980	$9,600
Underground Maintenance	$3,799	$77,178	($131)	$11,970	$7,037	$4,335
Engineering	($147,394)	($41,066)	$79,655	($101,772)	($29,625)	$2,092
Distribution Station Maintenance	$59,879	$3,319	($12,014)	($22,513)	$2,641	$1,993
Transformer Maintenance	$17,372	$12,607	($25,565)	($24,726)	$1,622	$349
Vegetation Maintenance	($12,975)	$14,459	($16,999)	$23,798	$1,404	$1,405
Building Maintenance	($31,060)	$16,170	$6,661	($5,546)	$4,042	$1,794
Administrative and Financial	($60,802)	$108,019	($58,616)	$33,863	($12,739)	$17,891
Sub-Total	($169,567)	$258,965	($183,422)	($15,517)	($610)	$48,240
Public and Regulatory Responsiveness						
Insurance	$2,970	($367)	$14,163	($29,714)	$805	$1,888
Regulatory Compliance	$30,302	($75,191)	$38,413	($39,651)	$27,702	($3,641)
Professional Fees & Dues	($57,098)	$62,471	($51,801)	$36,726	$68,410	($37,060)
Office Supplies & Telecommunications	$10,165	($3,290)	$2,977	($8,539)	$395	$2,806
Sub-Total	($13,661)	($16,378)	$3,752	($41,177)	$97,312	($36,007)
Total	**($273,334)**	**$294,302**	**($88,560)**	**($230,658)**	**$131,003**	**$22,316**

Variance Analysis Programs Discussion (based on OEB Appendix 2-JC)

In accordance with Chapter 2 Filing Requirements, LUI’s materiality threshold is $50,000 for a distributor with a distribution revenue requirement less than or equal to $10 million.

Customer Focus – Bad Debts and Collections

The 2017 Test Year balance of $47,527 is $78,441 less than the 2012 Board Approved amount of $125,968. The main reason for the variances are:

1) LUI is expecting a slight increase in bad debts expense from $18,583 in the 2012 Board Approved to $26,080 in the 2017 Test Year, an increase of $7,497. The increase is consistent with the increased frequency in which overdue accounts are sent to collections.

2) The increase in bad debts has been offset by a decrease in customer collecting (account 5320) by $88,778. The decrease is mainly the result of the retirement of two Customer Service Representatives and also the allocation of wages to customer billing (account 5315).

Operational Effectiveness – Meter Maintenance and Readings

The 2017 Test Year balance of $301,526 is $101,414 greater than the 2012 Board Approved amount of $200,113. The main reason for the variances are:

1) Meter maintenance expenses mainly consist of payments to Savage Data Systems Ltd., Utilismart Corporation, and Sensus Canada. The total paid in 2015 was $145,661 and LUI has projected inflationary increases in 2016 and 2017.

   Also included in meter maintenance and readings are wages. Similar to above, LUI has projected an inflationary increase in 2016 and 2017.

Operational Effectiveness – Overhead Maintenance

The 2017 Test Year balance of $329,589 is $75,135 greater than the 2015 actual balance of $288,009. The reason for the variances are:

1) Maintenance of Overhead Service (account 5130) is expected to increase by $52,490 in 2017. The increase is the result of planned annual maintenance associated with system inspections, infrared survey, and load break switch maintenance.

Operational Effectiveness – Underground Maintenance

The 2017 Test Year balance of $148,832 is $104,187 greater than the 2012 Board Approved amount of $44,645. The main reason for the variances are:

1) Increase is mainly due to an increase of $85,581 in Underground Distribution Lines (account 5040 and account 5045). Beginning in 2015, LUI outsourced locates to Promark Telecom and have budgeted $87,498 for the costs in 2017.

   In the 2012 Board Approved amount, these wages were recorded in account 5105 – Maintenance Supervision and Engineering and therefore the increase in Underground Maintenance is partially offset by the decrease in Engineering.

2) The additional increase is the result of an increase in Maintenance of Underground Services (account 5155) of $27,603. The increase is mainly the result of the hiring of a new lineman and the CPI increase in wages.

Operational Effectiveness – Engineering

The 2017 Test Year balance of $71,812 is $238,111 less than the 2012 Board Approved amount of $309,923. The main reasons for the variances are:

1) The 2017 Operation Supervision and Engineering are expected to decrease by $194,990. The 2012 Board Approved amount included costs associated with hiring a replacement for the Manager of Electric Distribution to assist with attrition planning. The replacement was hired in November 2013 and therefore the expenses 2017 have decreased from the 2012 Board Approved amount.

2) Included in the 2012 Board Approved amount was $52,313 associated with Maintenance Supervision and Engineering (account 5105). The costs primarily consisted of wages and these expenses were outsourced to Promark Telecom in 2015.

Ex.4/Tab 3/Sch.3 – Employee Compensation

LUI's overall compensation philosophy for all employees is designed to be competitive and equitable in order to attract and retain qualified personnel in an industry that is facing an aging workforce and is very competitive for skilled resources. The compensation package includes a base wage and benefits package. LUI's workforce is comprised of both unionized and non-unionized employees.

Compensation – Union

Compensation for unionized employees is negotiated through the collective bargaining process. When negotiated wage levels, consideration is given to the skill sets required to work within LUI's distribution system, as well as the competitive wage levels of its geographic market. They are represented by the Canadian Union of Public Employees (CUPE) Local #25.

LUI's Collective Agreement with unionized staff provides for annual pay increases and employee set progressions. Labour rates and benefits are adjusted annually based on negotiated percentages as per the collective agreement. The current collective agreement commenced February 1, 2014 and will expire January 31, 2017. LUI negotiated annual wage increases for 2014 to 2017 are 1.75%, 1.75%, and 2.0% respectively.

Compensation – Non-Union

Annual pay increases for non-union employees are based on performance targets established each year on corporate, department and individual objectives. In 2003 and 2012 the Hays system was used to evaluate non-union and management positions and this system of pay grids has been kept in place.

Pension

The employees of all LDCs are required to participate in the OMERS retirement plan. Therefore, the pension benefits provided to the employees of Lakefront Utilities Inc. are consistent with the pension benefits provided to employees of other LDCs.

Benefits

A comprehensive and competitive benefits package exists which includes health and dental insurance, life insurance, vacation and leave policies. The plans are designed to address the health and wellness needs of the employees.

All benefit plans for each employee group are essentially the same. The unionized benefit plans, negotiated through collective bargaining, play a significant role in driving the plan design for the non-unionized employees, with many plan provisions remaining common across all employee groups.

OEB Appendix 2-K presented at the next page details Lakefront Utilities Inc.'s employee compensation.

In accordance with Board policy which states that: “Where there are three, or fewer, full-time equivalents (FTEs) in any category, Lakefront Utilities Inc. may aggregate this category with the category to which it is most closely related. This higher level of aggregation may be continued, if required, to ensure that no category contains three, or fewer, FTEs”. LUI has separated out its Executive and Management employees in the FTEs but has lumped them in with the non-union employees for all other reporting in OEB Appendix 2-K.

OEB Appendix 2-K – Employee Compensation

	Last Rebasing Year - 2012 - Board Approved	Last Rebasing Year - 2012 - Actual	2013 Actuals	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year
Number of Employees (FTEs including Part-Time)							
Management (including executive)	3.25	3.70	3.65	4.05	2.77	2.46	2.46
Non-Management (union and non-union)	18.95	16.52	16.1	16.77	14.06	16.04	16.04
Total	22.20	20.22	19.75	20.82	16.83	18.50	18.50
Total Salary and Wages including overtime and incentive pay							
Management (including executive)							
Non-Management (union and non-union)	$1,634,980	$1,477,389	$1,493,761	$1,574,865	$1,319,512	$1,321,235	$1,342,148
Total	$1,634,980	$1,477,389	$1,493,761	$1,574,865	$1,319,512	$1,321,235	$1,342,148
Total Benefits (Current and Accrued)							
Management (including executive)						$0	$0
Non-Management (union and non-union)	$277,953	$387,525	$384,663	$434,869	$378,503	378,997	384,996
Total	$277,953	$387,525	$384,663	$434,869	$378,503	$378,997	$384,996
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$0	$0	$0	$0	$0	$0	$0
Non-Management (union and non-union)	$1,912,933	$1,864,914	$1,878,424	$2,009,734	$1,698,015	$1,700,232	$1,727,144
Total	$1,912,933	$1,864,914	$1,878,424	$2,009,734	$1,698,015	$1,700,232	$1,727,144

The 2012 Board Approved FTE for Management included wages for the President, Vice-President of Operations, Director of Finance and IT Manager. The actual 2012 FTE includes the aforementioned employees, as well as the Manager of Electric Distribution. The revision is a reallocation between Management and Non-Management and more accurately reflects LUI’s organizational chart and properly reflects the responsibilities and decision making within the organization.

Staffing and Compensation

The number of employees is based on the compensation of the number of full-time equivalent (FTE) positions throughout each of the fiscal years. A position that was added in a particular calendar year is counted as a portion of an FTE in the calendar year based on the start date of the position.

The salaries and wage amounts includes all salaries and wages paid, inclusive of overtime, vacations, float holidays, sick leave, bereavement leave, union meetings and other miscellaneous paid leave. The benefit amounts include the employer’s portion of statutory benefits (CPP and EI), employer contributions to EHT, WSIB, OMERS, and LUI’s costs for providing extended health care, dental, long-term disability, life insurance.

Employee Staffing Levels

The number of employees has decreased by 3.70 FTE since LUI’s last Cost of Service application. The main reason for the variance is as follows:

1) A decrease from 20.22 in 2012 to 19.75 in 2013 or 0.47 as a result of:

   - A decrease due to the departure of the IT manager as the IT costs were outsourced, and the departure of two journeyman lineman.

   - The decreases were offset by the hiring of three new journeyman lineman and the hiring of the Manager of Electric Distribution, to assist with the transition and impending retirement of the current manager. There was also the departure of the senior financial analyst, however, this position was replaced during the year with the finance supervisor and the net effect was insignificant.

2) An increase from 19.75 in 2013 to 20.82 in 2014 or 1.07 as a result of:

   - Hiring of an additional finance assistant to fill a gap in the finance department.

   - The remaining increase was the result of the remaining increases from the Manager of Electric Distribution and the two new journeyman lineman as they were hired mid/late 2013.

   - The increases above were partially offset by a decrease as a result of the departure of the Director of Finance.

3) A decrease in 2015 from 23.82 to 16.83 or 6.99 as a result of the retirement of:
   - Journeyman lineman
   - Manager of Electric Distribution
   - Technical Services Representative
   - Purchasing/Stock keeper
   - Customer Service Representative (2)
   - Director of Human Resources
   - Safety and Training Co-ordinator

   There was also an additional decrease with the departure of the financial/regulatory analyst in December 2014.

   The above decreases were offset by the replacement of the financial/regulatory analyst, and the hiring of an Electrical Distribution Technician and a CDM/Key Account Representative.

4) An increase in 2016 from 16.83 to 18.50 or 1.67, as a result of the hiring of a journeyman lineman and the hiring of a customer service representative.

Annual Wages

A summary of annual wage increase is presented in Table 4.9.

Table 4.9: Summary of Wage Increases by Year

	Union/Non-Union			Management	
Year	**% Increase**	**Cummulative**	**Year**	**% Increase**	**Cummulative**
February 1, 2012	3.00%	3.00%	February 1, 2012	3.00%	3.00%
February 1, 2013	3.00%	6.00%	February 1, 2013	3.00%	6.00%
February 1, 2014	1.75%	7.75%	February 1, 2014	1.75%	7.75%
February 1, 2015	1.75%	9.50%	February 1, 2015	1.75%	9.50%
February 1, 2016	2.00%	11.50%	February 1, 2016	2.00%	11.50%

Benefit Program Costs

A detailed summary of benefit program costs are presented in Table 4.10.

Statutory deductions have decreased 4.54% between 2012 Actual and 2017 Test Year, as a result of wage decreases, offset by annual increases in statutory rates.

Company benefits have increased 0.83% over the same time period mainly as a result of OMERS increases. Health and dental benefits have remained relatively stable with the increases mainly due to staff changing from single to family benefits.

LUI's latest Actuarial Report is found in Exhibit 4, Attachment B.

Table 4.10: Benefit Expenses

Benefit	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Bridge	2017 Test
Statutory						
CPP	45,367	47,883	49,084	41,564	41,628	42,289
EI	19,929	22,305	22,841	19,533	19,563	19,874
EHT	26,650	28,877	31,048	24,658	24,696	25,088
WSIB	12,745	15,531	16,766	12,470	12,489	12,688
Total Statutory	**104,691**	**114,596**	**119,739**	**98,225**	**98,376**	**99,939**
Company						
OMERS	127,717	109,904	150,135	122,204	122,392	124,336
Health	124,733	130,877	139,516	126,936	127,131	129,151
Life Insurance	30,384	29,285	25,480	31,138	31,186	31,681
Total Company	**282,834**	**270,066**	**315,131**	**280,278**	**280,710**	**285,168**
Total Benefit Costs	**387,525**	**384,662**	**434,870**	**378,503**	**379,086**	**385,107**

OMERS Pension Plan

LUI's employees are members of the Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan that most LDCs participate in, therefore the pension benefit provided to LUI's employees is consistent with that of other LDCs. The plan is a contributory defined benefit pension plan which is financed by equal contributions from the employer and employee based on the employee's contributory earnings. LUI's pension premium information is detailed in Table 4.10 above.

Ex.4/Tab 3/Sch.4 – Shared Services of Corporate Cost Allocation

LUI rents office space to Lakefront Utility Services Inc. (LUSI) and Cobourg Networks Inc. (CNI), LUI’s affiliate companies. The office space is a shared building space – LUSI’s office space is approximately 400 square feet and CNI’s office space is approximately 30 square feet. CNI was merged with LUSI effective January 1st 2016. The rent excludes property taxes, and excludes utilities.

Table 4.11: Shared Services

Year: 2012

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Lakefront Utilities Inc.	Lakefront Utility Services Inc.	Office Rental	Cost Based	48,000	48,000
Lakefront Utilities Inc.	Cobourg Networks Inc.	Office Rental	Cost Based	3,600	3,600
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Water and Sewer Billing Services	Cost Based	30,000	30,000
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Customer Billing and Collecting	Cost Based	218,856	218,856
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Community Relations	Cost Based	12,330	12,330
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Management and Administrative Wages and Benefits	Cost Based	482,738	482,738
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Office Supplies and Expenses	Cost Based	98,200	98,200
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Outside Services Employed	Cost Based	53,921	53,921
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Insurance	Cost Based	78,054	78,054
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Maintenance of General Plant	Cost Based	38,485	38,485

Year: 2013

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Lakefront Utilities Inc.	Lakefront Utility Services Inc.	Office Rental	Cost Based	48,000	48,000
Lakefront Utilities Inc.	Cobourg Networks Inc.	Office Rental	Cost Based	3,600	3,600
Lakefront Utilities Inc.	Lakefront Lighting Inc.	Office Rental	Cost Based	4,000	4,000
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Water and Sewer Billing Services	Cost Based	27,500	27,500
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Customer Billing and Collecting	Cost Based	287,238	287,238
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Community Relations	Cost Based	12,931	12,931
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Management and Administrative Wages and Benefits	Cost Based	571,152	571,152
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Office Supplies and Expenses	Cost Based	96,436	96,436
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Outside Services Employed	Cost Based	114,823	114,823
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Insurance	Cost Based	77,687	77,687
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Maintenance of General Plant	Cost Based	54,655	54,655

Year: 2014

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Lakefront Utilities Inc.	Lakefront Utility Services Inc.	Office Rental	Cost Based	48,000	48,000
Lakefront Utilities Inc.	Cobourg Networks Inc.	Office Rental	Cost Based	12,000	12,000
Lakefront Utilities Inc.	Lakefront Lighting Inc.	Office Rental	Cost Based	4,800	4,800
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Water and Sewer Billing Services	Cost Based	30,000	30,000
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Customer Billing and Collecting	Cost Based	277,925	277,925
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Community Relations	Cost Based	11,089	11,089
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Management and Administrative Wages and Benefits	Cost Based	516,252	516,252
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Office Supplies and Expenses	Cost Based	101,462	101,462
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Outside Services Employed	Cost Based	61,589	61,589
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Insurance	Cost Based	91,850	91,850
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Maintenance of General Plant	Cost Based	61,316	61,316

Year: 2015

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Lakefront Utilities Inc.	Lakefront Utility Services Inc.	Office Rental	Cost Based	48,720	48,720
Lakefront Utilities Inc.	Cobourg Networks Inc.	Office Rental	Cost Based	12,210	12,210
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Water and Sewer Billing Services	Cost Based	30,000	30,000
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Customer Billing and Collecting	Cost Based	203,543	203,543
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Community Relations	Cost Based	12,773	12,773
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Management and Administrative Wages and Benefits	Cost Based	509,299	509,299
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Office Supplies and Expenses	Cost Based	93,139	93,139
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Outside Services Employed	Cost Based	92,587	92,587
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Insurance	Cost Based	62,136	62,136
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Maintenance of General Plant	Cost Based	55,770	55,770

Year: 2016

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Lakefront Utilities Inc.	Lakefront Utility Services Inc.	Office Rental	Cost Based	62,758	62,758
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Water and Sewer Billing Services	Cost Based	30,000	30,000
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Customer Billing and Collecting	Cost Based	217,454	217,454
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Community Relations	Cost Based	19,630	19,630
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Management and Administrative Wages and Benefits	Cost Based	549,926	549,926
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Office Supplies and Expenses	Cost Based	93,534	93,534
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Outside Services Employed	Cost Based	159,697	159,697
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Insurance	Cost Based	62,941	62,941
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Maintenance of General Plant	Cost Based	59,812	59,812

Year: 2017

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Lakefront Utilities Inc.	Lakefront Utility Services Inc.	Office Rental	Cost Based	64,641	64,641
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Water and Sewer Billing Services	Cost Based	30,000	30,000
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Customer Billing and Collecting	Cost Based	223,978	223,978
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Community Relations	Cost Based	20,219	20,219
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Management and Administrative Wages and Benefits	Cost Based	566,424	566,424
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Office Supplies and Expenses	Cost Based	96,340	96,340
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Outside Services Employed	Cost Based	120,648	120,648
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Insurance	Cost Based	64,829	64,829
Lakefront Utility Services Inc.	Lakefront Utilities Inc.	Maintenance of General Plant	Cost Based	61,606	61,606

Ex.4/Tab 3/Sch.5 – Variance Analysis of Corporate Cost Allocation

2017 Test Year vs. 2012 Board Approved

The total cost allocation in 2017 of $1,248,685 is $184,501 more than the 2012 Board Approved amount of $689,967. The main reason for the variances are:

1) An increase in office rental to LUSI of $13,041 as a result of annual inflationary increases.

2) An increase in customer billing and collecting of $5,122. The increase is the net of a decrease as a result of retirements, an increase for one CSR replacement and inflationary increases in wages.

3) An increase in community relations of $7,889 as a result of increased customer engagement, including costs of preparing an annual report.

4) An increase of $83,686 in management and administrative wages and benefits. The total increase is primarily the result of inflationary increases in wages.

5) A decrease in office supplies and expenses of $1,860.

6) An increase in outside services employed of $66,727, primarily the result of an increase associated with an IT audit planned for 2016.

7) Insurance decreased by $13,225. In the past, LUI had paid for accounts receivable insurance of approximately $22,000 for two large customers. As the customers have not had issues paying their bill in time and LUI was able to obtain financial statements to determine financial viability, it was decided to cancel the insurance.

   The decrease in insurance was offset by annual inflationary increases.

8) An increase in maintenance of general plant of $23,121. The increase is a result of inflationary increases and increases consistent with the fact that LUI’s building is 85 years old and classified as heritage building in Cobourg.

Ex.4/Tab 3/Sch.6 – Reconciliation of Revenue

LUI's services provided to its affiliates outlined in OEB Appendix 2-N are reconciled as recorded in the USoA accounts in Table 4.12: Reconciliation of Revenues from Affiliates below.

Table 4.12: Reconciliation of Revenue from Affiliates

Item	Source Account	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Bridge	2017 Test
Building Rent	4205 - Interdepartment Rent	51,600	55,600	64,800	60,930	62,758	64,641
Pole Rentals	4210 - Rent from Electric Property	67,144	48,429	65,093	76,692	78,993	81,363
Total		**118,744**	**104,029**	**129,893**	**137,622**	**141,751**	**146,003**

Ex.4/Tab 3/Sch.7 – Purchases of Non-Affiliate Services

LUI purchases equipment, materials, and services in a cost effective manner with full consideration given to price as well as product quality, the ability to deliver on time, reliability, compliance with engineering specifications and quality of service. Vendors are screened to ensure knowledge, reputation, and the capability to meet Lakefront Utilities Inc.'s needs. The procurement of goods and/or services for LUI is carried out with the highest ethical standards and consideration to the public nature of the expenditures.

Purchase Authorization

The Board of Directors approve all purchases over $150,000 after three quotes are obtained. The approval is either done during the budget process or if needed, outside the budget process at the quarterly Board meetings.

Tendering

When goods or services are tendered, a tender/request for proposal/request for quote will be issued to a minimum of three vendors, if availability permits.

LUI's 2015 vendor list over the materiality threshold of $50,000 is presented in Table 4.13: Products and Services from Non-Affiliates.

Table 4.13: Products and Services from Non Affiliates 2015

Supplier Name	Service Product	Procurement Method	Document Amount
IESO	Electricity	Single Source	25,180,503
Hydro One Networks Inc.	Distributor	Single Source	3,714,146
Ontario Electricity Financial Corp	Debt Retirement	Regulated	1,730,626
Anixter Power	Materials	Quote/Tender	370,095
K.P.C. Power Electrical Ltd.	Maintenance/Capital work	Quote/Tender	152,906
MEARIE Group	Insurance/training/life and LTD insurance	Industry	80,388
ERTH Holdings Inc.	Meter maintenance, billing system maintenance	RFQ	108,442
Ascent Solutions Inc.	Materials/Maintenance	Quote/Tender	142,212
Survalent Technology	Capital work	Quote/Tender	138,891
Burman Energy Consultants Group	CDM Services	Quote/Tender	118,804
G&W Canada	Capital work	Quote/Tender	117,493
Posi-Plus Technologies Inc.	Capital work	Quote/Tender	113,678
Sensus Canada	Meter reading	Quote/Tender	98,370
Raven Engineering	Maintenance/Capital work	Quote/Tender	99,017
Promark Telecon Inc.	Locates	Quote/Tender	73,434

Ex.4/Tab 3/Sch.8 – One-Time Costs

The only noteworthy one-time cost relates to the preparation costs associated with the 2017 Cost of Service application which are amortized over a period of five years. Regulatory costs are discussed at the next section.

Ex.4/Tab 3/Sch.9 – Regulatory Costs

OEB Appendix 2-M: Regulatory Costs below shows LUI's regulatory costs for the 2012 Board Approved, 2015 and for the 2016 Bridge and 2017 Test Year.

The second part of the chart for OEB Appendix 2-M below details the breakout of the costs forecast to occur in order to prepare the 2017 application. The total cost of $118,150 is for consultant costs, legal fees, and costs of hiring a third party to do customer engagement. The costs will be amortized over a 5 year period in the amount of $23,630 per year.

All regulatory costs listed below are tracked in account 5655 – Regulatory Expenses. LUI notes that it did not include any costs related to Settlement Conference and/or Oral Hearing. As an effort to keep OM&A costs to a minimum, and as noted at Exhibit 1, the utility wishes to proceed with the review of the application by way of written hearing. However, if the OEB requires the utility to go to settlement or oral hearing, the utility reserves the right to increase its Regulatory Costs accordingly.

Appendix 2-M: Regulatory Costs

Regulatory Cost Category		USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2012 Board Approved)	Most Current Actuals Year 2015	2016 Bridge Year	Annual % Change	2017 Test Year	Annual % Change
(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 34,633	$ 28,540	$ 28,800	0.91%	$ 29,664	3.00%
2	OEB Section 30 Costs (Applicant-originated)	5655		On-Going	$ 1,412	$ 1,570	$ 1,200	-23.56%	$ 1,236	3.00%
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going						
4	Expert Witness costs for regulatory matters	5655								
5	Legal costs for regulatory matters	5655		One-Time	$ 18,055					
6	Consultants' costs for regulatory matters	5655		One-Time	$ 35,382	$ 3,290	$ 3,000	-8.80%	$ 3,300	10.00%
7	Operating expenses associated with staff resources allocated to regulatory matters	5655		On-Going	$ 3,752	$ 5,839	$ 10,310	76.58%	$ 5,469	-46.95%
8	Operating expenses associated with other resources allocated to regulatory matters [1]	5655								
9	Other regulatory agency fees or assessments	5655								
10	Any other costs for regulatory matters (please define)	5655		On-Going	$ 5,754					
11	Intervenor costs			One-Time	$ 4,575					
12	Sub-total - Ongoing Costs [3]	▨	$ -	▨	$ 45,550	$ 39,238	$ 43,310	10.38%	$ 39,669	-8.41%
13	Sub-total - One-time Costs [4]	▨	$ -	▨	$ 58,012	$ -	$ 23,630		$ 23,630	0.00%
14	Total	▨	$ -	▨	$ 103,562	$ 39,238	$ 66,940	70.60%	$ 63,299	-5.44%

		Historical Year(s)	2016 Bridge Year	2017 Test Year	Amortized over 5 years
4	Expert Witness costs				
5	Legal costs		$28,350		$5,670
6	Consultants' costs		$19,800		$3,960
7	Incremental operating expenses associated with staff resources allocated to this application.				$0
8	Incremental operating expenses associated with other resources allocated to this application. [1]		$70,000		$14,000
11	Intervenor costs				
	Total		$118,150		$23,630

Ex.4/Tab 3/Sch.10 – Low Income Energy Assistance Programs

LUI has included $5,850 of expense for the Low Income Energy Assistance Program (LEAP) under Deductions – Donation Expense (USoA #6205). This amount is based on the Board's determination that the greater of 0.12% of a distributor's Board-Approved distribution revenue requirement, or $2,000 should be included in the utility's costs.

LUI has partnered with The Help Centre of Northumberland to assist in the LEAP program intended to provide emergency relief to eligible low-income customers who may be experiencing difficulty paying current arrears to LUI.

In compliance with OEB policy, LUI:

- Collects money from ratepayers for LEAP EFA in the amount approved by the OEB;
- Transfers program funds to the Help Centre of Northumberland;
- Determines funding allocations within their service territory by geography;
- Establishes partnerships, contracts, and operational procedures with the Help Centre;
- Receives, records and takes appropriate action upon notification from an Intake Agency (or Lead Agency as appropriate) that an assessment of eligibility is being undertaken;
- Receives, records and takes appropriate action upon notification from an Intake Agency (or Lead Agency as appropriate) of decision on applications;
- Confirms customer and account information used in determining program eligibility, including information on payment history; and
- Reports to the OEB in accordance with OEB reporting requirements through filings 2.1.1.6

LUI no longer participates in any Winter Warmth programs.

Ex.4/Tab 3/Sch.11 – Charitable and Political Donations

LUI does not donate to charities and as such, the utility confirms that no charitable donations have been included in OM&A expenses for 2017 other than the $5,850 for LEAP funding.

LUI does not make any political donations.

Depreciation, Amortization & Depletion

Ex.4/Tab 4/Sch.1 – Depreciation Rate and Methodology

LUI does not have a formal depreciation/amortization policy but bases its practice for depreciation/amortization on MIFRS, and guidelines set out by the Ontario Energy Board, where applicable. LUI has converted to IFRS January 1, 2015 and as such the depreciation/amortization policy in effect for the 2016 Bridge Year and 2017 Test Year is compliant with MIFRS.

On July 17, 2012 the Board issued a statement that changes to depreciation rates and capitalization policies that would have been implemented under IFRS could be made in 2012 under CGAAP (effective January 1, 2012), and must be made to later than 2013 (effective January 1, 2013) regardless of where the Accounting Standards Board (AcSB) permitted further deferrals beyond 2013 for the changeover to IFRS. In 2012, LUI implemented the change to depreciation rates and componentization of Property, Plant and Equipment (PP&E). Useful lives were guided by the Kinectrics report and LUI confirms that parts or components of PP&E are being depreciated separately. LUI presented its changes to useful lives/depreciation rates and the components therefore in its last COS application (EB-2011-0250) and continues to use the same useful lives on a go-forward basis.

LUI does not have any capitalized borrowing costs in any of the years presented in this application.

Ex.4/Tab 4/Sch.2 – Depreciation Expense

In accordance with the filing requirements, LUI has completed depreciation and amortization expense tables for the following:

- 2012 MIFRS (Table 4.14) – Board Appendix 2-CB
- 2013 MIFRS (Table 4.15) – Board Appendix 2-CC
- 2014 MIFRS (Table 4.16) – Board Appendix 2-CD
- 2015 MIFRS (Table 4.17) – Board Appendix 2-CE
- 2016 MIFRS (Table 4.18) – Board Appendix 2-CF
- 2017 MIFRS (Table 4.19) – Board Appendix 2-CG

As stated previously, LUI adopted a change in capitalization and useful lives policies for their assets in 2012. This was submitted and approved during LUI’s 2012 Cost of Service Application (EB-2011-0250).

Table 4.14 – 2012 MIFRS Depreciation Expense – Appendix 2-CB

Year 2012 MIFRS

Account	Description	Opening NBV as at Jan 1, 2012 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2012 Depreciation Expense (k) = (j) + (h)	2012 Depreciation Expense per Appendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2012 Full Year Additions (n) = (d)/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2012 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 67,109	$ 277,365	2.00	10.00	10.00%	$ 33,555	$ 13,868	$ 47,423	$ 48,998	-$ 1,575	$ 27,737		$ 61,291
1612	Land Rights (Formally known as Account 1906)					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1805	Land	$ 219,284				0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ 818,486	$ 153,163	47.80	50.00	2.00%	$ 17,123	$ 1,532	$ 18,655	$ 12,729	$ 5,926	$ 3,063		$ 20,186
1810	Leasehold Improvements					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 1,202,655	$ 22,303	34.50	45.00	2.22%	$ 34,860	$ 248	$ 35,107	$ 33,681	$ 1,426	$ 496		$ 35,355
1825	Storage Battery Equipment					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 1,165,264	$ 263,466	42.00	45.00	2.22%	$ 27,744	$ 2,927	$ 30,672	$ 22,649	$ 8,023	$ 5,855		$ 33,599
1835	Overhead Conductors & Devices	$ 3,218,487	$ 774,550	45.20	55.00	1.82%	$ 71,205	$ 7,041	$ 78,247	$ 43,645	$ 34,602	$ 14,083		$ 85,288
1840	Underground Conduit	$ 730,709	$ 3,350	48.50	50.00	2.00%	$ 15,066	$ 34	$ 15,100	$ 12,896	$ 2,204	$ 67		$ 15,133
1845	Underground Conductors & Devices	$ 1,280,053	$ 227,824	22.20	35.00	2.86%	$ 57,660	$ 3,255	$ 60,915	$ 62,611	-$ 1,696	$ 6,509		$ 64,169
1850	Line Transformers	$ 2,855,663	$ 265,754	21.65	35.00	2.86%	$ 131,901	$ 3,796	$ 135,698	$ 101,838	$ 33,860	$ 7,593		$ 139,494
1855	Services (Overhead & Underground)	$ 354,950	$ 14,709	45.55	55.00	1.82%	$ 7,793	$ 134	$ 7,926	$ 2,256	$ 5,670	$ 267		$ 8,060
1860	Meters	$ 349,480		11.50	25.00	4.00%	$ 30,390	$ -	$ 30,390	$ 31,681	-$ 1,291	$ -		$ 30,390
1860	Meters (Smart Meters)		$ 2,044,874	15.00	15.00	6.67%	$ -	$ 68,162	$ 68,162	$ 68,162	$ 0	$ 136,325		$ 136,325
1905	Land					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1910	Leasehold Improvements					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 49,172	$ 31,047	8.25	10.00	10.00%	$ 5,960	$ 1,552	$ 7,513	$ 6,680	$ 833	$ 3,105		$ 9,065
1915	Office Furniture & Equipment (5 years)					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 20,404	$ 21,321	3.50	5.00	20.00%	$ 5,830	$ 2,132	$ 7,962	$ 7,900	$ 62	$ 4,264		$ 10,094
1920	Computer Equip.-Hardware(Post Mar. 22/04)					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 514,869	$ 317,215	6.25	8.00	12.50%	$ 82,379	$ 19,826	$ 102,205	$ 105,115	-$ 2,910	$ 39,652		$ 122,031
1935	Stores Equipment					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 180,160	$ 32,759	8.50	10.00	10.00%	$ 21,195	$ 1,638	$ 22,833	$ 22,989	-$ 156	$ 3,276		$ 24,471
1945	Measurement & Testing Equipment	$ 17,955		9.50	10.00	10.00%	$ 1,890	$ -	$ 1,890	$ 1,772	$ 118	$ -		$ 1,890
1950	Power Operated Equipment					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ 996	$ 1,426	9.50	10.00	10.00%	$ 105	$ 71	$ 176	$ 157	$ 19	$ 143		$ 247
1970	Load Management Controls Customer Premises					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment		$ 97,796	20.00	20.00	5.00%	$ -	$ 2,445	$ 2,445	$ 2,445	-$ 0	$ 4,890		$ 4,890
1985	Miscellaneous Fixed Assets					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 1,951,474	-$ 152,967	23.50	25.00	4.00%	-$ 83,041	-$ 3,059	-$ 86,101	-$ 86,608	$ 507	-$ 6,119		-$ 89,160
	Total	**$11,094,222**	**$ 4,395,955**				**$ 461,614**	**$ 125,602**	**$ 587,217**	**$ 501,596**	**$ 85,621**	**$ 251,205**	**$ -**	**$ 712,819**

Table 4.15 – 2013 MIFRS Depreciation Expense – Appendix 2-CC

2013 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2013 Depreciation Expense [1] (h)=2012 Full Year Deprecation + ((d)*0.5)/(f)	2013 Depreciation Expense per Apppendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (h) - (l)	Depreciation Expense on 2013 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2013 Full Year Depreciation [3] (p) = 2012 Full Year Depreciation + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 26,107	10.00	10.00%	$ 62,596	$ 76,176	-$ 13,580	$ 2,611		$ 63,902
1612	Land Rights (Formally known as Account 1906)	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1805	Land	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ 38,411	50.00	2.00%	$ 20,571	$ 28,715	-$ 8,144	$ 768		$ 20,955
1810	Leasehold Improvements	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 67,234	45.00	2.22%	$ 36,102	$ 55,745	-$ 19,643	$ 1,494		$ 36,849
1825	Storage Battery Equipment	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 133,398	45.00	2.22%	$ 35,081	$ 47,472	-$ 12,391	$ 2,964		$ 36,564
1835	Overhead Conductors & Devices	$ 190,493	55.00	1.82%	$ 87,020	$ 108,963	-$ 21,943	$ 3,464		$ 88,752
1840	Underground Conduit	$ 86,322	50.00	2.00%	$ 15,996	$ 26,590	-$ 10,594	$ 1,726		$ 16,860
1845	Underground Conductors & Devices	$ 151,915	35.00	2.86%	$ 66,340	$ 90,460	-$ 24,120	$ 4,340		$ 68,510
1850	Line Transformers	$ 153,741	35.00	2.86%	$ 141,691	$ 157,657	-$ 15,966	$ 4,393		$ 143,887
1855	Services (Overhead & Underground)	$ 80,834	55.00	1.82%	$ 8,795	$ 9,343	-$ 548	$ 1,470		$ 9,530
1860	Meters	$ 117,332	25.00	4.00%	$ 32,736	$ 37,804	-$ 5,068	$ 4,693		$ 35,083
1860	Meters (Smart Meters)	$ -		0.00%	$ 136,325	$ 140,236	-$ 3,911	$ -		$ 136,325
1905	Land	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1910	Leasehold Improvements	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 13,799	10.00	10.00%	$ 9,755	$ 9,784	-$ 29	$ 1,380		$ 10,445
1915	Office Furniture & Equipment (5 years)	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 24,126	5.00	20.00%	$ 12,507	$ 12,691	-$ 184	$ 4,825		$ 14,919
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ -		0.00%	$ 122,031	$ 114,134	$ 7,897	$ -		$ 122,031
1935	Stores Equipment	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 181,952	10.00	10.00%	$ 33,569	$ 35,198	-$ 1,629	$ 18,195		$ 42,666
1945	Measurement & Testing Equipment	$ 1,476	10.00	10.00%	$ 1,964	$ 2,087	-$ 123	$ 148		$ 2,038
1950	Power Operated Equipment	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ 10,500	10.00	10.00%	$ 772	$ 844	-$ 72	$ 1,050		$ 1,297
1970	Load Management Controls Customer Premises	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 4,312	20.00	5.00%	$ 4,998	$ 4,998	-$ 0	$ 216		$ 5,105
1985	Miscellaneous Fixed Assets	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 392,384	25.00	4.00%	-$ 97,008	-$ 97,693	$ 685	-$ 15,695		-$ 104,855
	Total	**$ 889,568**			**$ 731,840**	**$ 861,204**	**-$ 129,364**	**$ 38,042**	**$ -**	**$ 750,861**

Table 4.16 – 2014 MIFRS Depreciation Expense – Appendix 2-CD

2014 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2014 Depreciation Expense [1] (h)=2013 Full Year Deprecation + ((d)*0.5)/(f)	2014 Depreciation Expense per Apppendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (h) - (l)	Depreciation Expense on 2014 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2014 Full Year Depreciation [3] (p) = 2013 Full Year Depreciation + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 19,400	10.00	10.00%	$ 64,872	$ 76,707	-$ 11,835	$ 1,940		$ 65,842
1612	Land Rights (Formally known as Account 1906)	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1805	Land	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ 54,231	50.00	2.00%	$ 21,497	$ 30,007	-$ 8,510	$ 1,085		$ 22,039
1810	Leasehold Improvements	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 80,630	45.00	2.22%	$ 37,745	$ 54,397	-$ 16,652	$ 1,792		$ 38,641
1825	Storage Battery Equipment	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 245,546	45.00	2.22%	$ 39,292	$ 51,421	-$ 12,129	$ 5,457		$ 42,020
1835	Overhead Conductors & Devices	$ 399,016	55.00	1.82%	$ 92,379	$ 109,850	-$ 17,471	$ 7,255		$ 96,007
1840	Underground Conduit	$ 18,558	50.00	2.00%	$ 17,045	$ 27,661	-$ 10,616	$ 371		$ 17,231
1845	Underground Conductors & Devices	$ 18,007	35.00	2.86%	$ 68,767	$ 90,546	-$ 21,779	$ 514		$ 69,024
1850	Line Transformers	$ 112,751	35.00	2.86%	$ 145,498	$ 161,753	-$ 16,255	$ 3,221		$ 147,108
1855	Services (Overhead & Underground)	$ -	55.00	1.82%	$ 9,530	$ 9,931	-$ 401	$ -		$ 9,530
1860	Meters	$ -	25.00	4.00%	$ 35,083	$ 33,809	$ 1,274	$ -		$ 35,083
1860	Meters (Smart Meters)	$ 68,805	15.00	6.67%	$ 138,618	$ 147,044	-$ 8,426	$ 4,587		$ 140,912
1905	Land	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1910	Leasehold Improvements	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ -	10.00	10.00%	$ 10,445	$ 10,442	$ 3	$ -		$ 10,445
1915	Office Furniture & Equipment (5 years)	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 21,136	5.00	20.00%	$ 17,033	$ 16,868	$ 165	$ 4,227		$ 19,146
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 77,846	8.00	12.50%	$ 126,896	$ 146,082	-$ 19,186	$ 9,731		$ 131,762
1935	Stores Equipment	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 186,821	10.00	10.00%	$ 52,007	$ 53,656	-$ 1,649	$ 18,682		$ 61,348
1945	Measurement & Testing Equipment	$ -	10.00	10.00%	$ 2,038	$ 2,225	-$ 187	$ -		$ 2,038
1950	Power Operated Equipment	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ 42,293	10.00	10.00%	$ 3,412	$ 3,350	$ 62	$ 4,229		$ 5,527
1970	Load Management Controls Customer Premises	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 85,064	20.00	5.00%	$ 7,232	$ 7,232	$ -	$ 4,253		$ 9,359
1985	Miscellaneous Fixed Assets	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	$ -	25.00	4.00%	-$ 104,855	-$ 100,710	-$ 4,145	$ -		-$ 104,855
	Total	**$ 1,430,104**			**$ 784,533**	**$ 932,271**	**-$ 147,738**	**$ 67,344**	**$ -**	**$ 818,205**

Table 4.17 – 2015 MIFRS Depreciation Expense – Appendix 2-CE

2015 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2015 Depreciation Expense [1] (h)=2014 Full Year Depreciation + ((d)*0.5)/(f)	2015 Depreciation Expense per Appendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (h) - (l)	Depreciation Expense on 2015 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2015 Full Year Depreciation [3] (p) = 2014 Full Year Depreciation + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 215,982	10.00	10.00%	$ 76,641	$ 100,245	-$ 23,604	$ 21,598		$ 87,440
1612	Land Rights (Formally known as Account 1906)	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1805	Land	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ -	50.00	2.00%	$ 22,039	$ 30,550	-$ 8,511	$ -		$ 22,039
1810	Leasehold Improvements	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 339,833	45.00	2.22%	$ 42,417	$ 59,068	-$ 16,651	$ 7,552		$ 46,193
1825	Storage Battery Equipment	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 295,393	45.00	2.22%	$ 45,302	$ 56,842	-$ 11,540	$ 6,564		$ 48,584
1835	Overhead Conductors & Devices	$ 282,760	55.00	1.82%	$ 98,577	$ 113,703	-$ 15,126	$ 5,141		$ 101,148
1840	Underground Conduit	$ -	50.00	2.00%	$ 17,231	$ 27,846	-$ 10,615	$ -		$ 17,231
1845	Underground Conductors & Devices	$ 75,391	35.00	2.86%	$ 70,101	$ 105,558	-$ 35,457	$ 2,154		$ 71,178
1850	Line Transformers	$ 62,788	35.00	2.86%	$ 148,005	$ 164,261	-$ 16,256	$ 1,794		$ 148,902
1855	Services (Overhead & Underground)	$ 239,787	55.00	1.82%	$ 11,710	$ 12,111	-$ 401	$ 4,360		$ 13,889
1860	Meters	$ -	25.00	4.00%	$ 35,083	$ 33,809	$ 1,274	$ -		$ 35,083
1860	Meters (Smart Meters)	$ 39,921	15.00	6.67%	$ 142,243	$ 150,668	-$ 8,425	$ 2,661		$ 143,573
1905	Land	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1910	Leasehold Improvements	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ -	10.00	10.00%	$ 10,445	$ 10,442	$ 3	$ -		$ 10,445
1915	Office Furniture & Equipment (5 years)	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 29,160	5.00	20.00%	$ 22,062	$ 19,852	$ 2,210	$ 5,832		$ 24,978
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ -	8.00	12.50%	$ 131,762	$ 147,667	-$ 15,905	$ -		$ 131,762
1935	Stores Equipment	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 5,368	10.00	10.00%	$ 61,617	$ 62,353	-$ 736	$ 537		$ 61,885
1945	Measurement & Testing Equipment	$ -	10.00	10.00%	$ 2,038	$ 2,225	-$ 187	$ -		$ 2,038
1950	Power Operated Equipment	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ 107,577	10.00	10.00%	$ 10,906	$ 10,844	$ 62	$ 10,758		$ 16,284
1970	Load Management Controls Customer Premises	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 145,085	20.00	5.00%	$ 12,986	$ 12,986	-$ 0	$ 7,254		$ 16,613
1985	Miscellaneous Fixed Assets	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -	-	0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 58,465	25.00	4.00%	-$ 106,025	-$ 106,728	$ 703	-$ 2,339		-$ 107,194
	Total	**$ 1,780,580**			**$ 855,139**	**$ 1,014,302**	**-$ 159,163**	**$ 73,867**	**$ -**	**$ 892,072**

Table 4.18 – 2016 MIFRS Depreciation Expense – Appendix 2-CF

2016 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2016 Depreciation Expense [1] (h)=2015 Full Year Depreciation + ((d)*0.5)/(f)	2016 Depreciation Expense per Appendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 10,000	10.00	10.00%	$ 87,940	$ 108,511.00	-$ 20,571
1612	Land Rights (Formally known as Account 1906)	$ -	-	0.00%	$ -	$ -	$ -
1805	Land	$ -	-	0.00%	$ -	$ -	$ -
1808	Buildings	$ 10,000	50.00	2.00%	$ 22,139	$ 30,649.00	-$ 8,510
1810	Leasehold Improvements	$ -	-	0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -	-	0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 599,000	45.00	2.22%	$ 52,848	$ 69,500.00	-$ 16,652
1825	Storage Battery Equipment	$ -	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 207,631	45.00	2.22%	$ 50,891	$ 63,074.00	-$ 12,183
1835	Overhead Conductors & Devices	$ 197,837	55.00	1.82%	$ 102,946	$ 118,090.00	-$ 15,144
1840	Underground Conduit	$ -	50.00	2.00%	$ 17,231	$ 27,846.00	-$ 10,615
1845	Underground Conductors & Devices	$ 58,750	35.00	2.86%	$ 72,018	$ 106,536.00	-$ 34,518
1850	Line Transformers	$ 56,280	35.00	2.86%	$ 149,706	$ 165,321.00	-$ 15,615
1855	Services (Overhead & Underground)	$ 140,302	55.00	1.82%	$ 15,165	$ 15,647.00	-$ 482
1860	Meters	$ -	25.00	4.00%	$ 35,083	$ 33,809.00	$ 1,274
1860	Meters (Smart Meters)	$ 35,000	15.00	6.67%	$ 144,740	$ 153,399.00	-$ 8,659
1905	Land	$ -	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ -	-	0.00%	$ -	$ -	$ -
1910	Leasehold Improvements	$ -	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ -	10.00	10.00%	$ 10,445	$ 10,442.00	$ 3
1915	Office Furniture & Equipment (5 years)	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 15,000	5.00	20.00%	$ 26,478	$ 20,649.00	$ 5,829
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	-	0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ 280,000	8.00	12.50%	$ 149,262	$ 148,750.00	$ 512
1935	Stores Equipment	$ -	-	0.00%	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 5,000	10.00	10.00%	$ 62,135	$ 62,587.00	-$ 452
1945	Measurement & Testing Equipment	$ -	10.00	10.00%	$ 2,038	$ 2,225.00	-$ 187
1950	Power Operated Equipment	$ -	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ -	-	0.00%	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 78,000	10.00	10.00%	$ 20,184	$ 19,773.00	$ 411
1970	Load Management Controls Customer Premises	$ -	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -	20.00	5.00%	$ 16,613	$ 16,613.00	-$ 0
1985	Miscellaneous Fixed Assets	$ -	-	0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	$ -	25.00	4.00%	-$ 107,194	-$ 107,897.00	$ 703
	Total	$1,692,800			$ 930,668	$ 1,065,524	-$ 134,856

Table 4.19 – 2017 MIFRS Depreciation Expense – Appendix 2-CG

2017 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2017 Depreciation Expense [1] (h)=2016 Full Year Depreciation + ((d)*0.5)/(f)	2017 Depreciation Expense per Appendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 10,000	10.00	10.00%	**$88,440**	$82,904	**$5,536**
1612	Land Rights (Formally known as Account 1906)	$ -	-	0.00%	**$0**	$0	**$0**
1805	Land	$ -	-	0.00%	**$0**	$0	**$0**
1808	Buildings	$ 10,000	50.00	2.00%	**$22,239**	$30,849	**-$8,610**
1810	Leasehold Improvements	$ -	-	0.00%	**$0**	$0	**$0**
1815	Transformer Station Equipment >50 kV	$ -	-	0.00%	**$0**	$0	**$0**
1820	Distribution Station Equipment <50 kV	$ 550,000	45.00	2.22%	**$58,960**	$81,268	**-$22,308**
1825	Storage Battery Equipment	$ -	-	0.00%	**$0**	$0	**$0**
1830	Poles, Towers & Fixtures	$ 265,320	45.00	2.22%	**$53,839**	$68,536	**-$14,697**
1835	Overhead Conductors & Devices	$ 258,665	55.00	1.82%	**$105,298**	$122,792	**-$17,494**
1840	Underground Conduit	$ -	50.00	2.00%	**$17,231**	$27,846	**-$10,615**
1845	Underground Conductors & Devices	$ 211,454	35.00	2.86%	**$75,038**	$105,475	**-$30,437**
1850	Line Transformers	$ 73,584	35.00	2.86%	**$150,757**	$160,000	**-$9,243**
1855	Services (Overhead & Underground)	$ 168,067	55.00	1.82%	**$16,693**	$18,993	**-$2,300**
1860	Meters	$ -	25.00	4.00%	**$35,083**	$26,425	**$8,658**
1860	Meters (Smart Meters)	$ 76,500	15.00	6.67%	**$147,290**	$157,349	**-$10,059**
1905	Land	$ -	-	0.00%	**$0**	$0	**$0**
1908	Buildings & Fixtures	$ -	-	0.00%	**$0**	$0	**$0**
1910	Leasehold Improvements	$ -	-	0.00%	**$0**	$0	**$0**
1915	Office Furniture & Equipment (10 years)	$ -	10.00	10.00%	**$10,445**	$0	**$10,445**
1915	Office Furniture & Equipment (5 years)	$ -	-	0.00%	**$0**	$10,442	**-$10,442**
1920	Computer Equipment - Hardware	$ 15,000	5.00	20.00%	**$27,978**	$21,516	**$6,462**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	-	0.00%	**$0**	$0	**$0**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	-	0.00%	**$0**	$0	**$0**
1930	Transportation Equipment	$ 35,000	8.00	12.50%	**$151,449**	$149,901	**$1,548**
1935	Stores Equipment	$ -	-	0.00%	**$0**	$0	**$0**
1940	Tools, Shop & Garage Equipment	$ 5,000	10.00	10.00%	**$62,385**	$61,828	**$557**
1945	Measurement & Testing Equipment	$ -	10.00	10.00%	**$2,038**	$2,225	**-$187**
1950	Power Operated Equipment	$ -	-	0.00%	**$0**	$0	**$0**
1955	Communications Equipment	$ -	-	0.00%	**$0**	$0	**$0**
1955	Communication Equipment (Smart Meters)	$ -	-	0.00%	**$0**	$0	**$0**
1960	Miscellaneous Equipment	$ 21,000	10.00	10.00%	**$21,234**	$24,373	**-$3,139**
1970	Load Management Controls Customer Premises	$ -	-	0.00%	**$0**	$0	**$0**
1975	Load Management Controls Utility Premises	$ -	-	0.00%	**$0**	$0	**$0**
1980	System Supervisor Equipment	$ -	20.00	5.00%	**$16,613**	$16,613	**$0**
1985	Miscellaneous Fixed Assets	$ -	-	0.00%	**$0**	$0	**$0**
1990	Other Tangible Property	$ -	-	0.00%	**$0**	$0	**$0**
1995	Contributions & Grants	$ -	25.00	4.00%	**-$107,194**	-$107,897	**$703**
	Total	**$ 1,699,590**			**$955,816**	**$1,061,438**	**-$105,622**
	Depreciation exp. adj. from gain or loss on the retirement of assets (pool of like assets)						
	Total Depreciation expense to be included in the test year revenue requirement				**$955,816**		

Ex.4/Tab 4/Sch.3 – Typical Useful Lives Study

The Board-sponsored Kinetrics study, on which the utility has based its depreciation rates that were approved in LUI's last Cost of Service (EB-2011-0250), are presented below as Table 4.20: Comparison of Depreciation Rates.

Table 4.20: Comparison of Depreciation Rates

USoA Account Number	Description	Current (EB-2011-0250)	Proposed
1611	Computer Software (Formally known as Account 1925)	5.00	5.00
1808	Building	50.00	50.00
1820	Distribution Station Equipment <50kV	45.00	45.00
1830	Poles, Towers & Fixtures	45.00	45.00
1835	Overhead Conductors & Devices	55.00	55.00
1840	Conduit	50.00	50.00
1845	Underground Conductors & Devices	35.00	35.00
1850	Line Transformers	35.00	35.00
1855	Services (Overhead & Underground)	55.00	55.00
1860	Meters	25.00	25.00
1860	Meters (Smart Meters)	15.00	15.00
1915	Office Furniture & Equipment	10.00	10.00
1920	Computer Equipment - Hardware	5.00	5.00
1930	Transportation Equipment - cars	5.00	5.00
1930	Transportation Equipment - trucks	8.00	8.00
1940	Tools, Shop & Garage Equipment	10.00	10.00
1960	Miscellaneous Equipment	-	10.00
1980	System Supervisory Equipment	-	20.00
1995	Contributions & Grants	-	25.00

Ex.4/Tab 4/Sch.4 – OEB Appendix 2-BB

Table 4.21 below, consistent with Board Appendix 2-BB, provides a summary of the life comparison between LUI's selected useful lives and those provided in Table F-1 of the Kinetrics Report.

Table 4.21: Service Life Comparison – Appendix 2-BB

		Asset Details			Useful Life			USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
Parent*	#	Category| Component | Type			MIN UL	TUL	MAX UL			Years	Rate	Years	Rate	Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers and Fixtures	45	2%	45	2%	No	No
			Cross Arm	Wood	20	40	55	1830	Poles, Towers and Fixtures	45	2%	45	2%	No	No
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	3	Fully Dressed Steel Poles	Overall		60	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95	1830	Poles, Towers and Fixtures	45	2%	45	2%	No	No
	4	OH Line Switch			30	45	55	1835	Undgerground Conductors and Devices	55	2%	45	2%	No	No
	5	OH Line Switch Motor			15	25	25								
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60	1835	Undgerground Conductors and Devices	55	2%	45	2%	No	No
	8	OH Conductors			50	60	75	1835	Undgerground Conductors and Devices	55	2%	45	2%	Yes	No
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Line Transformers	35	3%	40	3%	No	No
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55								
TS & MS	12	Power Transformers	Overall		30	45	60	1820	Distribution Station Equipment	45	2%	45	2%	No	No
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55								
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30								
			Battery Bank		10	15	15								
			Charger		20	20	30								
	16	Station Metal Clad Switchgear	Overall		30	40	60	1820	Distribution Station Equipment	45	2%	45	2%	No	No
			Removable Breaker		25	40	60	1820	Distribution Station Equipment	45	2%	45	2%	No	No
	17	Station Independent Breakers			35	45	65	1820	Distribution Station Equipment	45	2%	45	2%	No	No
	18	Station Switch			30	50	60	1820	Distribution Station Equipment	45	2%	45	2%	No	No
	19	Electromechanical Relays			25	35	50								
	20	Solid State Relays			10	30	45	1820	Distribution Station Equipment	45	2%	45	2%	No	No
	21	Digital & Numeric Relays			15	20	20	1820	Distribution Station Equipment	45	2%	45	2%	No	Yes
	22	Rigid Busbars			30	55	60								
	23	Steel Structure			35	50	90	1820	Distribution Station Equipment	45	2%	45	2%	No	No
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75								
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30								
	27	Primary Non-TR XLPE Cables in Duct			20	25	30	1845	Undgerground Conductor	35	3%	30	3%	No	No
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40	1855	Secondary Services	55	2%	35	3%	No	No
	32	Secondary Cables in Duct			35	40	60								
	33	Network Tranformers	Overall		20	35	50								
			Protector		20	35	40								
	34	Pad-Mounted Transformers			25	40	45	1850	Transformer	35	3%	40	3%	No	No
	35	Submersible/Vault Transformers			25	35	45								
	36	UG Foundation			35	55	70								
	37	UG Vaults	Overall		40	60	80								
			Roof		20	30	45								
	38	UG Vault Switches			20	35	50								
	39	Pad-Mounted Switchgear			20	30	45								
	40	Ducts			30	50	85	1840	Conduit	50	2%	50	2%	No	No
	41	Concrete Encased Duct Banks			35	55	80								
	42	Cable Chambers			50	60	80								
S	43	Remote SCADA			15	20	30	1980	SCADA	20	5%	20	5%	No	No

Table F-2 from Kinetics Report[1]

	Asset Details		Useful Life Range		USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
#	Category| Component | Type						Years	Rate	Years	Rate	Below Min Range	Above Max Range
1	Office Equipment		5	15	1915	Office Equipment	10	10%	10	10%	No	No
2	Vehicles	Trucks & Buckets	5	15	1930	Transportation Equipment	5	20%	5	20%	No	No
		Trailers	5	20								
		Vans	5	10								
3	Administrative Buildings		50	75	1808	Buildings	50	2%	50	2%	No	No
4	Leasehold Improvements		Lease dependent									
5	Station Buildings	Station Buildings	50	75	1820	Distribution Station Equipment	45	2%	45	2%	Yes	No
		Parking	25	30								
		Fence	25	60	1820	Distribution Station Equipment	45	2%	45	2%	No	No
		Roof	20	30								
6	Computer Equipment	Hardware	3	5	1920	Computer Hardware	5	20%	5	20%	No	No
		Software	2	5	1611	Computer Software	5	20%	5	20%	No	No
7	Equipment	Power Operated	5	10								
		Stores	5	10								
		Tools, Shop, Garage Equipment	5	10	1940	Tools	10	10%	10	10%	No	No
		Measurement & Testing Equipment	5	10	1960	Measurement & Testing Equipment	10	10%	10	10%	No	No
8	Communication	Towers	60	70								
		Wireless	2	10	1980	System Supervisor Equipment	20	5%	20	5%	No	Yes
9	Residential Energy Meters		25	35								
10	Industrial/Commercial Energy Meters		25	35	1860	Meters	25	4%	25	4%	No	No
11	Wholesale Energy Meters		15	30	1860	Meters	25	4%	25	4%	No	No
12	Current & Potential Transformer (CT & PT)		35	50								
13	Smart Meters		5	15	1860	Meters	25	4%	25	4%	No	Yes
14	Repeaters - Smart Metering		10	15								
15	Data Collectors - Smart Metering		15	20								

Ex.4/Tab 4/Sch.5 – Depreciation Expense Associated with Retirement Obligation

At this time, LUI does not have any Asset Retirement Obligations (“AROs”), associated depreciation, or accretion expenses in relation to AROs to report as part of this Application.

Ex.4/Tab 4/Sch.6 – Depreciation and Capitalization Policy

LUI does not have a formal depreciation/amortization policy but bases its practice for depreciation/amortization on MIFRS, and guidelines set out by the Ontario Energy Board, where applicable. LUI has converted to IFRS January 1, 2015 and as such the depreciation/amortization policy in effect for the 2016 Bridge Year and 2017 Test Year is compliant with MIFRS.

LUI calculates depreciation based on the “Half year” rule for all distribution system assets and capital contributions.

A summary of LUI’s depreciation by year from 2012 Board Approved to the 2017 Test Year is provided in Table 4.22 on the next page.

Table 4.22: Depreciation Expenses Summary

		2012 Board Approved	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year	Depreciation Rate
USoA	**Description**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	
1611	Computer Software (Formally known as Account 1925)	67,578	48,998	76,176	76,707	100,245	108,511	82,904	10.00%
1612	Land Rights (Formally known as Account 1906 and 1806)	0	0	0	0	0	0	0	0.00%
1805	Land	0	0	0	0	0	0	0	0.00%
1808	Buildings	25,859	12,729	28,715	30,007	30,550	30,649	30,849	2.00%
1810	Leasehold Improvements	0	0	0	0	0	0	0	0.00%
1815	Transformer Station Equipment >50 kV	0	0	0	0	0	0	0	0.00%
1820	Distribution Station Equipment <50 kV	49,799	33,681	55,745	54,397	59,068	69,500	81,268	2.22%
1825	Storage Battery Equipment	0	0	0	0	0	0	0	0.00%
1830	Poles, Towers & Fixtures	39,108	22,649	47,472	51,421	56,842	63,074	68,536	2.22%
1835	Overhead Conductors & Devices	86,558	43,645	108,963	109,850	113,703	118,090	122,792	1.82%
1840	Underground Conduit	24,905	12,896	26,590	27,661	27,846	27,846	27,846	2.00%
1845	Underground Conductors & Devices	74,723	62,611	90,460	90,546	105,558	106,536	105,475	2.86%
1850	Line Transformers	136,676	101,838	157,657	161,753	164,261	165,321	160,000	2.86%
1855	Services (Overhead & Underground)	7,820	2,256	9,343	9,931	12,111	15,647	18,993	1.82%
1860	Meters	35,455	31,681	37,804	33,809	33,809	33,809	26,425	4.00%
1860	Meters (Smart Meters)	109,276	68,162	140,236	147,044	150,668	153,399	157,349	6.67%
1905	Land	0	0	0	0	0	0	0	0.00%
1908	Buildings & Fixtures	0	0	0	0	0	0	0	0.00%
1910	Leasehold Improvements	0	0	0	0	0	0	0	0.00%
1915	Office Furniture & Equipment (10 years)	6,615	6,680	9,784	10,442	10,442	10,442	10,442	10.00%
1915	Office Furniture & Equipment (5 years)		0	0	0	0	0	0	0.00%
1920	Computer Equipment - Hardware	19,302	7,900	12,691	16,868	19,852	20,649	21,516	20.00%
1920	Computer Equip.-Hardware(Post Mar. 22/04)	0	0	0	0	0	0	0	0.00%
1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0.00%
1930	Transportation Equipment	91,195	105,115	114,134	146,082	147,667	148,750	149,901	12.50%
1935	Stores Equipment	0	0	0	0	0	0	0	0.00%
1940	Tools, Shop & Garage Equipment	40,392	22,989	35,198	53,656	62,353	62,587	61,828	10.00%
1945	Measurement & Testing Equipment	1,907	1,772	2,087	2,225	2,225	2,225	2,225	10.00%
1950	Power Operated Equipment	0	0	0	0	0	0	0	0.00%
1955	Communications Equipment	0	0	0	0	0	0	0	0.00%
1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0.00%
1960	Miscellaneous Equipment	0	157	844	3,350	10,844	19,773	24,373	10.00%
1970	Load Management Controls Customer Premises	0	0	0	0	0	0	0	0.00%
1975	Load Management Controls Utility Premises	0	0	0	0	0	0	0	0.00%
1980	System Supervisor Equipment	0	2,445	4,998	7,232	12,986	16,613	16,613	5.00%
1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0.00%
1990	Other Tangible Property	0	0	0	0	0	0	0	0.00%
1995	Contributions & Grants	(78,020)	(86,608)	(97,693)	(100,710)	(106,728)	(107,897)	(107,897)	4.00%
Total Depreciation		**739,148**	**501,597**	**861,205**	**932,271**	**1,014,303**	**1,065,522**	**1,061,439**	
Less: Fully Allocated Depreciation		**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Total Depreciation for Rate Setting Purposes		**739,148**	**501,597**	**861,205**	**932,271**	**1,014,303**	**1,065,522**	**1,061,439**	

Ex.4/Tab 4/Sch.7 – Adoption of Half Year Rule

LUI confirms that it has applied the half-year rule for the purposes of computing the net book value of Property, Plant, and Equipment and General Plant to include in the rate base. Under the half-year rule, acquisitions and investments made during the year are amortized assuming they entered service at the mid-point of the year.

Taxes or Payments In Lieu of Taxes (PILS) and Property Taxes

Ex.4/Tab 5/Sch.1 – Overview of PILs

LUI is required to make payments in lieu of income taxes (“taxes”) based on its taxable income. LUI files Federal/Provincial tax returns annually. There have been no special circumstances that would require specific tax planning measures to minimize taxes payable. There are no outstanding audits, reassessments or disputes relating to the tax returns filed by LUI.

There are no non-utility activities included in LUI’s financial results, therefore the entire amount of PILs payable is considered in the proposed allowance to be included in the revenue requirement.

LUI has used the OEB Tax Work Form model to calculate the amount of taxes for inclusion in its 2017 rates. PILs have been calculated under MIFRS accounting policies.

Table 4.23 summarizes LUI’s grossed up taxes for the 2015 Historical Year, 2016 Bridge Year and 2017 Test Year. Under the new accounting policies, LUI’s PILs amount is $134,477.

Table 4.23: Income Tax Summary

Year	Grossed-Up PILs
2012 Board Approved	$22,112
2012 Actual	$534,948
2013 Actual	$74,753
2014 Actual	$123,038
2015 Actual	$104,291
2016 Bridge Year	$133,534
2017 Test Year	$134,477

The income tax sheet from the Revenue Requirement Work Form is presented below as Table 4.24 and the PILs mode is being filed in conjunction with this application.

Table 4.24: Tax Provision for the 2017 Test Year

Line No.	Particulars	Application
	Determination of Taxable Income	
1	Utility net income before taxes	$726,705
2	Adjustments required to arrive at taxable utility income	($353,721)
3	Taxable income	$372,984
	Calculation of Utility income Taxes	
4	Income taxes	$98,841
6	Total taxes	$98,841
7	Gross-up of Income Taxes	$35,636
8	Grossed-up Income Taxes	$134,477
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$134,477
10	Other tax Credits	$ -
	Tax Rates	
11	Federal tax (%)	15.00%
12	Provincial tax (%)	11.50%
13	Total tax rate (%)	26.50%

Ex.4/Tab 5/Sch.2 – Latest Filed Tax Return, Tax Assessments and Correspondence

The utility's latest tax return is presented in this Exhibit, Attachment C.

LUI does not have any loss carry forwards. The financial statements are not different than the statement filed in this application. Therefore, financial statements have not been included with the tax return in Attachment C.

Ex.4/Tab 5/Sch.3 – Calculation of Tax Credits

LUI is not claiming an Apprenticeship Training Tax Credit or Scientific Research and Experimental Development ("SRED").

Ex.4/Tab 5/Sch.4 – Non-recoverable and Disallowed Expenses

LUI has no donation other than LEAP, in calculation of revenue requirement.

Ex.4/Tab 5/Sch.5 – Integrity Checklist

LUI attests that the following integrity checks have been completed in its application. In completing the PILs model, LUI attests that:

- The depreciation and amortization added back in the application's PILs model agree with the numbers disclosed in the rate base section of the application;

- The capital additions and deductions in the UCC/CCA Schedule 8 agree with the rate base section for historic, bridge and test years;

- Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31st historic year UCC that agrees with the opening bridge year UCC at January 1st;

- The CCA deductions in the application's PILs tax model for historic, bridge and test years agree with the numbers in the UCC schedules for the same years filed in the application;

- Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application;

- CCA is maximized even if there are tax loss carry-forwards; and

- LUI does not have any loss carry forwards

Ex.4/Tab 5/Sch.6 – Property Taxes

LUI has forecasted the 2016 Bridge and 2017 Test Year property taxes using 2015 actual property taxes of $59,997 and increase to:

2016: $61,167

2017: $62,359

The increase in 2016 and 2017 represent a 1.95% inflationary increase.

Conservation and Demand Side Management

Ex.4/Tab 6/Sch.1 – Overview of CDM

LUI filed its CDM Strategy with the OEB in accordance with the CDM Code for Electricity Distributors in the fall of 2010 for LUI's 2011-2014 CDM portfolio. LUI began delivering CDM programs in 2011 in order to meet the mandated targets. The emphasis has been on Ontario Power Authority ("OPA") Contracted Province-Wide Programs to residential and general service customers. LUI has not sought approval for Board-Approved CDM programs. LUI is currently in the process of using the 2015-2020 CDM portfolio.

The IESO (formerly OPA) provides funding for LUI's CDM programs. Funding the expenditures for the delivery of IESO Contracted Province-Wide Programs are kept separate and tracked in Non-Distribution Revenue Accounts in accordance with the guidance in Chapter 5, Accounting Treatment of the CDM Code.

In addition, LUI has ensured that any function performed within the distribution company for CDM activity has been attributed and tracked in the non-distribution accounts. Therefore, CDM activities are not included in the calculation of revenue requirement or revenue offsets.

LUI will not be applying for any OM&A costs related to the administration and delivery of CDM programs to be recovered through the revenue requirement.

Ex.4/Tab 6/Sch.2 – LRAMVA

On March 31, 2010, the Minister of Energy and Infrastructure issued a directive (the "Directive") to the Board regarding electricity CDM targets to be met by licensed electricity distributors. The Directive required that the Board amend the licenses of distributors to add, as a condition of license, the requirement for distributors to achieve reductions in electricity demand through the delivery of CDM programs over a four-year period beginning January 1, 2011. Section 12 of the Directive required that the Board have regard to the objective that lost revenues that resulted from CDM Programs should not act as a disincentive to a distributor. On April 26, 2012, the Board issued Guidelines for Electricity Distributor Conservation and Demand Management ("CDM Guidelines"). In keeping with the Directive, the Board adopted a mechanism to capture the difference between the results of actual, verified impacts of authorized CDM activities undertaken by distributors between 2011 and 2014 and the level of activities embedded into rates through the distributors load forecast in an LRAM variance account.

Table 4.26: Summary of Requested LRAMVA Amounts (2011-2014)

Particulars	2011 LRAMVA	2012 LRAMVA	2013 LRAMVA	2014 LRAMVA	Total
Total LRAMVA - Pre 2011 Programs Completed in 2011	1,511	1,579	1,620	1,639	
Total LRAMVA - 2011 OPA Program Results	7,267	7,488	7,620	7,140	
Total LRAMVA - 2012 OPA Program Results		5,917	5,976	6,015	
Total LRAMVA - 2013 OPA Program Results			10,211	10,221	
Total LRAMVA - 2014 OPA Program Results				11,341	
Total LRAMVA - 2014 OPA Program Results	**8,778**	**14,984**	**25,427**	**36,356**	**85,545**

LUI has used the most recent input assumptions when calculating lost revenue and has relied on the 2014 final evaluation report and the 2011-2014 Finalized CDM results from the IESO in support of its LRAM calculation for its contracted province-wide CDM programs ("OPA Programs") for 2011-2013. Lost revenues are based on Board approved variable charges and carrying charges through to December 31, 2016 are requested using the quarterly rates prescribed by the Board provided in Exhibit 9.

LUI is not currently requesting recovery of lost revenue resulting from Board-approved programs.

LRAMVA Calculations

				2011				2012				2013				2014				Distribution Volumetric Rates				Total LRAM				
	Incentive Name	Persistence	Program Year	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Gross Summer Peak Demand Savings (kW)	Gross Energy Savings (kWh)	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Gross Summer Peak Demand Savings (kW)	Gross Energy Savings (kWh)	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Gross Summer Peak Demand Savings (kW)	Gross Energy Savings (kWh)	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Gross Summer Peak Demand Savings (kW)	Gross Energy Savings (kWh)	2011 Dist Vol Rate	2012 Dist Vol Rate	2013 Dist Vol Rate	2014 Dist Vol Rate	2011 LRAMVA	2012 LRAMVA	2013 LRAMVA	2014 LRAMVA	
	Residential																			0.0134	0.0143	0.0144	0.0146					
	GS<50																			0.0081	0.0082	0.0082	0.0083					
	Pre-2011 Programs Completed in 2011																			Distribution Volumetric Rates				Total LRAM				
				2011				2012				2013				2014				2011	2012	2013	2014	2011	2012	2013	2014	
Residential	Electricity Retrofit Incentive Program		pre 2011	18.85	111,742			18.85	111,742			18.85	111,742			18.85	111,742			0.0134	0.0140	0.0144	0.0145	$1,497.34	$1,564.39	$1,605.36	$1,623.98	
	High Performance New Construction		pre 2011	0.15	832			0.15	832			0.15	832			0.15	832			0.0134	0.0140	0.0144	0.0145	$11.15	$11.65	$11.95	$12.09	
	Electricity Retrofit Incentive Program		pre 2011	0.00	0.00			0.00	0			0.00	0			0.00	0			0.0134	0.0140	0.0144	0.0145	$0.00	$0.00	$0.00	$0.00	
	High Performance New Construction		pre 2011	0.00	209			0.00	209				209			0.00	209			0.0134	0.0140	0.0144	0.0145	$2.80	$2.93	$3.00	$3.04	
																				0.0134	0.0140	0.0144	0.0145	$0.00	$0.00	$0.00	$0.00	
	Adjustments																			0.0134	0.0140	0.0144	0.0145	$0.00	$0.00	$0.00	$0.00	
																				0.0134	0.0140	0.0144	0.0145	$0.00	$0.00	$0.00	$0.00	
																				0.0134	0.0140	0.0144	0.0145	$0.00	$0.00	$0.00	$0.00	
																				0.0134	0.0140	0.0144	0.0145	$0.00	$0.00	$0.00	$0.00	
																				0.0134	0.0140	0.0144	0.0145	$0.00	$0.00	$0.00	$0.00	
	Total			19.00	112783.00	0.00	0.00	19.00	112783.00	0.00	0.00	19.00	112783.00	0.00	0.00	19.00	112783.00	0.00	0.00					1511.29	1578.96	1620.32	1639.11	
GS<50			pre 2011																	0.0081	0.0082	0.0082	0.0083	$0.00	$0.00	$0.00	$0.00	
			pre 2011																	0.0081	0.0082	0.0082	0.0083	$0.00	$0.00	$0.00	$0.00	
	Total			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00					0.00	0.00	0.00	0.00	
																								1511.29	1578.96	1620.32	1639.11	6349.68
	Programs Completed in 2011																			Distribution Volumetric Rates				Total LRAM				
				2011				2012				2013				2014				2011	2012	2013	2014	2011	2012	2013	2014	
Residential	Appliance Retirement		2011	6.00	43,268			6.00	43,268			6.00	43,268			6.00	40,128			0.0134	0.0140	0.0144	0.0145	$579.79	$605.75	$621.62	$583.19	
	Appliance Exchange		2011	1.00	825			1.00	825			1.00	825			1.00	765			0.0134	0.0140	0.0144	0.0145	$11.06	$11.55	$11.85	$11.12	
	HVAC Incentives		2011	62.00	118,914			62.00	118,914			62.00	118,914			62.00	110,285			0.0134	0.0140	0.0144	0.0145	$1,593.45	$1,664.80	$1,708.40	$1,602.80	
	Conservation Instant Coupon Booklet		2011	2.00	36,294			2.00	36,294			2.00	36,294			2.00	33,660			0.0134	0.0140	0.0144	0.0145	$486.34	$508.12	$521.42	$489.19	
	Bi-Annual Retailer Event		2011	3.00	56,036			3.00	56,036			3.00	56,036			3.00	51,970			0.0134	0.0140	0.0144	0.0145	$750.88	$784.50	$805.05	$755.29	
	Retailer Co-op		2011					0.00	0			0.00	0			0.00	0			0.0134	0.0140	0.0144	0.0145	$0.00	$0.00	$0.00	$0.00	
	Residential Demand Response (switch/pstat)†		2011					0.00	0			0.00	0			0.00	0			0.0134	0.0140	0.0144	0.0145	$0.00	$0.00	$0.00	$0.00	
	Residential Demand Response (IHD)†		2011					0.00	0			0.00	0			0.00	0			0.0134	0.0140	0.0144	0.0145	$0.00	$0.00	$0.00	$0.00	
	Residential New Construction		2011					0.00	0			0.00	0.00			0.00	0			0.0134	0.0140	0.0144	0.0145	$0.00	$0.00	$0.00	$0.00	
	Adjustments																			0.0134	0.0140	0.0144	0.0145	$0.00	$0.00	$0.00	$0.00	
	Adjustments to 2011 Verified Results		2011	0.00	73785.14			0.00	73785.14			0.00	73785.14			0.00	68430.63			0.0134	0.0140	0.0144	0.0145	$988.72	$1,032.99	$1,060.05	$994.53	
																				0.0134	0.0140	0.0144	0.0145	$0.00	$0.00	$0.00	$0.00	
																				0.0134	0.0140	0.0144	0.0145	$0.00	$0.00	$0.00	$0.00	
																				0.0134	0.0140	0.0144	0.0145	$0.00	$0.00	$0.00	$0.00	
	Total			74.00	329,122	0.00	0.00	74.00	329,122	0.00	0.00	74.00	329,122	0.00	0.00	74.00	305,238	0.00	0.00					4410.24	4607.71	4728.39	4436.13	
GS<50	Retrofit		2011	11.00	44,447			11.00	44,447			11.00	44,447			11.00	41,222			0.0081	0.0082	0.0082	0.0083	$360.02	$362.98	$364.47	$340.76	
	Direct Install Lighting		2011	116.00	308,217			116.00	308,217			116.00	308,217			116.00	285,850			0.0081	0.0082	0.0082	0.0083	$2,496.56	$2,517.11	$2,527.38	$2,363.03	
	Energy Manager		2011	0.00	0.00			0.00	0			0.00	0.00			0.00	0			0.0081	0.0082	0.0082	0.0083	$0.00	$0.00	$0.00	$0.00	
	Total			127.00	352,664	0.00	0.00	127.00	352,664	0.00	0.00	127.00	352,664	0.00	0.00	127.00	327,072	0.00	0.00					2856.58	2880.09	2891.84	2703.79	
																								7266.82	7487.80	7620.23	7139.92	29514.77
	Programs Completed in 2012																			Distribution Volumetric Rates				Total LRAM				
				2011				2012				2013				2014				2011	2012	2013	2014	2011	2012	2013	2014	
Residential	Appliance Retirement		2012					3.00	25,892			1.80	25,815			1.08	25,739				0.0140	0.0144	0.0145		$362.49	$370.88	$374.07	
	Appliance Exchange		2012					1.00	1,509			0.60	1,505			0.36	1,500				0.0140	0.0144	0.0145		$21.13	$21.61	$21.80	
	HVAC Incentives		2012					33.00	58,485			19.77	58,311			11.85	58,138				0.0140	0.0144	0.0145		$818.79	$837.74	$844.95	
	Conservation Instant Coupon Booklet		2012					0.00	2,666			0.00	2,658			0.00	2,650				0.0140	0.0144	0.0145		$37.32	$38.19	$38.52	
	Bi-Annual Retailer Event		2012					3.00	51,067			1.80	50,915			1.08	50,764				0.0140	0.0144	0.0145		$714.94	$731.49	$737.78	
	Retailer Co-op		2012					0.00	0.00			0.00	0			0.00	0				0.0140	0.0144	0.0145		$0.00	$0.00	$0.00	
	Residential Demand Response (switch/pstat)†		2012					0.00	0.00			0.00	0			0.00	0				0.0140	0.0144	0.0145		$0.00	$0.00	$0.00	
	Home Assistance Program		2012					2.00	26046.00			1.20	25,969			0.72	25,892				0.0140	0.0144	0.0145		$364.64	$373.08	$376.29	
	Residential New Construction		2012					0.00	0.00			0.00	0			0.00	0				0.0140	0.0144	0.0145		$0.00	$0.00	$0.00	
	Adjustments																				0.0140	0.0144	0.0145		$0.00	$0.00	$0.00	
	Adjustments to 2012 Verified Results		2012					0.00	4,928			0.00	4,913			0.00	4,898				0.0140	0.0144	0.0145		$68.99	$70.58	$71.19	
									0			0.00	0			0.00	0				0.0140	0.0144	0.0145		$0.00	$0.00	$0.00	
									0			0.00	0			0.00	0				0.0140	0.0144	0.0145		$0.00	$0.00	$0.00	
									0			0.00	0			0.00	0				0.0140	0.0144	0.0145		$0.00	$0.00	$0.00	
									0			0.00	0			0.00	0				0.0140	0.0144	0.0145		$0.00	$0.00	$0.00	
	Total			0.00	0.00	0.00	0.00	42.00	170,593	0.00	0.00	25.17	170,086	0.00	0.00	15.08	169,582	0.00	0.00						2388.30	2443.58	2464.59	
GS<50	Retrofit		2012					57	271,670			34.15	270,864			20.46	270,060				0.0082	0.0082	0.0083		$2,218.64	$2,221.08	$2,232.50	
	Direct Install Lighting		2012					28	110,062			16.78	109,735			10.05	109,410				0.0082	0.0082	0.0083		$898.84	$899.83	$904.45	
	Energy Audit		2012					10.00	50,353			5.99	50,204			3.59	50,055				0.0082	0.0082	0.0083		$411.22	$411.67	$413.78	
	Total			0.00	0.00	0.00	0.00	95.00	432,085	0.00	0.00	56.92	430,803	0.00	0.00	34.11	429,525	0.00	0.00						3528.69	3532.58	3550.74	
																									5916.99	5976.16	6015.32	17908.48
	Programs Completed in 2013																			Distribution Volumetric Rates				Total LRAM				
				2011				2012				2013				2014				2011	2012	2013	2014	2011	2012	2013	2014	
Residential	Appliance Retirement		2013									3.00	19,992			1.21	19,812					0.0144	0.0145			$287.22	$287.93	
	Appliance Exchange		2013									5.00	8,497			2.02	8,420					0.0144	0.0145			$122.07	$122.38	
	HVAC Incentives		2013									38.00	68,390			15.34	67,774					0.0144	0.0145			$982.54	$984.98	
	Conservation Instant Coupon Booklet		2013									1.00	14,697			0.40	14,565					0.0144	0.0145			$211.15	$211.67	
	Bi-Annual Retailer Event		2013									2.00	32,758			0.81	32,463					0.0144	0.0145			$470.62	$471.79	
	Retailer Co-op		2013													0.00	0					0.0144	0.0145			$0.00	$0.00	
	Residential Demand Response (switch/pstat)†		2013													0.00	0					0.0144	0.0145			$0.00	$0.00	
	Home Assistance Program		2013									5.00	75,767			2.02	75,084					0.0144	0.0145			$1,088.52	$1,091.23	
	Residential New Construction		2013									1.00	8,283			0.40	8,208					0.0144	0.0145			$119.00	$119.30	
	Adjustments																					0.0144	0.0145			$0.00	$0.00	
	Adjustments to 2013 Verified Results		2013										173431.20			0.00	171,869					0.0144	0.0145			$2,491.63	$2,497.83	
																						0.0144	0.0145			$0.00	$0.00	
																						0.0144	0.0145			$0.00	$0.00	
																							0.0145				$0.00	
																						0.0144	0.0145			$0.00	$0.00	
																						0.0144	0.0145			$0.00	$0.00	
	Total			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	55.00	401,815	0.00	0.00	22.20	398,195	0.00	0.00							5772.75	5787.10	
GS<50	Retrofit		2013									60	292,770			24.22	290,132					0.0082	0.0083			$2,400.71	$2,398.43	
	Direct Install Lighting		2013									49	174,051			19.78	172,483					0.0082	0.0083			$1,427.22	$1,425.86	
	New Construction		2013									12	74396			4.84	73,726					0.0082	0.0083			$610.05	$609.47	
	Total			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	121.00	541,217	0.00	0.00	48.84	536,341	0.00	0.00							4437.98	4433.75	
																										10210.72	10220.86	20431.58
	Programs Completed in 2014																			Distribution Volumetric Rates				Total LRAM				
				2011				2012				2013				2014				2011	2012	2013	2014	2011	2012	2013	2014	
Residential	Appliance Retirement		2014													5.00	29,768						0.0145				$432.63	
	Appliance Exchange		2014													1.00	2,217						0.0145				$32.22	
	HVAC Incentives		2014													39.00	72,906						0.0145				$1,059.57	
	Conservation Instant Coupon Booklet		2014													5.00	56,616						0.0145				$822.82	
	Bi-Annual Retailer Event		2014													15.00	234,350						0.0145				$3,405.89	
	Retailer Co-op		2014													1.00							0.0145				$0.00	
	Residential Demand Response (switch/pstat)†		2014																				0.0145				$0.00	
	Residential Demand Response (IHD)†		2014																				0.0145				$0.00	
	Residential New Construction		2014													1.00	10,799						0.0145				$156.95	
	Home Assistance Program															6.00	33,436						0.0145				$485.94	
	Adjustments																						0.0145				$0.00	
																							0.0145				$0.00	
																							0.0145				$0.00	
																							0.0145				$0.00	
																							0.0145				$0.00	
																							0.0145				$0.00	
	Total			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	73.00	440,092	0.00	0.00								6396.00	
GS<50	Retrofit		2014													29	248,761						0.0083				$2,056.42	
	Direct Install Lighting		2014													85	349,386						0.0083				$2,888.26	
	Energy Manager		2014																				0.0083				$0.00	
	Total			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	114.00	598,147	0.00	0.00								4944.68	
																											11340.69	
																								8,778	14,984	25,427	36,356	85,545

Attachments

Attachment A	LUI Collective Agreement
Attachment B	LUI Actuarial Report
Attachment C	2015 Tax Return
Attachment D	2011-2014 Final CDM Results

Attachment A - LUI Collective Agreement

COLLECTIVE AGREEMENT

BETWEEN

LAKEFRONT UTILITY SERVICES INC.
(hereinafter referred to as LUSI)

AND
LOCAL 25
CANADIAN UNION OF PUBLIC EMPLOYEES
(OUTSIDE AND OFFICE EMPLOYEES)
(hereinafter referred to as the Union)

FEBRUARY 1, 2014 TO JANUARY 31, 2017

Table of Contents – Collective Agreement

ARTICLE 1 - PURPOSE OF AGREEMENT

1.1 The Purpose of this Agreement is to maintain a harmonious relationship between LUSI and the employees and to provide a means of settling differences through the grievance/arbitration process.

ARTICLE 2 – UNION RECOGNITION

2.1 LUSI agrees to recognize the Union as the sole bargaining agent in respect to hours of work, wages and working conditions set out in the agreement for all employees, save and except the President, Vice President, Director of HR/Executive Assistant, Sr. Financial Analyst, Financial Assistant, Financial Analyst, Customer Service Supervisor, HR Generalist, Manager Water Treatment & Distribution, Manager Electric Distribution, Electric Distribution Supervisor, Water Distribution Supervisor, Water Treatment Supervisor and persons above the ranks so listed.

2.2 The Employer will not condone any discrimination, bullying or harassment of employees by any of its management staff, representatives or employees.

2.3 The Union will not condone any discrimination, bullying or harassment of employees by any of its members or representatives.

ARTICLE 3 – MANAGEMENT RIGHTS

3.1 The Union acknowledges that except as specifically restricted by this Agreement, LUSI retains all rights to run the business and direct the working force and, not restricting the generality of the foregoing, LUSI has the right to:

(a) Manage its affairs, hire, promote, transfer, lay off or demote employees.
(b) Discipline, or discharge any employee for just cause.

3.2 LUSI agrees that these functions shall be executed in a manner consistent with the general purpose and intent of this Agreement and subject to the right of an employee to lodge a grievance as set forth herein.

ARTICLE 4 – UNION SECURITY AND CHECK-OFF

4.1 All future employees (in accordance with Article 2.1) must become members within sixty (60) days of their employment and retain their membership so long as the Union is recognized as the Collective Bargaining Agent for all the employees (in accordance with Article 2.1) of LUSI.

4.2 LUSI agrees that it be a condition of employment whether members or non-members after the waiting period of sixty (60) days, each employee shall pay an amount equal to the monthly dues and such money shall be deducted from every pay cheque, and remitted to the Secretary-Treasurer of the Union. The Union agrees to keep LUSI informed of the name of the Secretary-Treasurer, and to give one (1) month's notice of any change in the amount of dues to be deducted.

4.3 LUSI will provide the Union with a listing of employees covered by this Agreement. This listing will indicate for each employee his/her date of hire and occupational classification. The Employer will provide notification to the Union, in writing, of the engagement of any new bargaining-unit member, defining the particulars of employment.

4.4 Every new employee shall be given a copy of this Collective Agreement upon joining LUSI.

4.5 When Management holds a disciplinary meeting with an employee, the Union Steward shall be present.

ARTICLE 5 – STATUS OF EMPLOYEES

5.1 **Temporary Employees** – A temporary employee is an employee hired for a period of limited duration, for relief during sick leave, vacation, maternity leave and swing shift relief, or for a position which is not likely to become a continuing position within LUSI, not to exceed six (6) months. Such period may be extended as deemed necessary by both parties. When a Paternity Leave has been granted, the notice of a temporary replacement to the Union shall suffice for the entire leave.

The hiring of a temporary employee will not result in the layoff or demotion of full-time employees. The hiring of temporary employees will not be used in any way as to eliminate continuous full-time positions.

All temporary employees, covering unionized positions, shall pay union dues after sixty (60) days worked. A temporary employee will not be entitled to the benefits provided in this Agreement except as specifically provided in this Agreement.

5.2 **Probationary Employees** – A probationary employee is an employee hired on trial for a period not exceeding six (6) months. During this probationary period an employee shall not be considered having regular status and will be entitled only to those provisions of this collective Agreement specifically identified as applying to probationary employees. The probationary employee may be terminated at the sole discretion of Management without recourse to the grievance and arbitration procedure.

Management may grant a time extension to a probationary employee to meet the relocation requirements.

5.3 **Regular Employees** – If a probationary employee satisfactorily completes his/her probationary period of six (6) months, then that employee is deemed to be a regular employee.

If a time extension is granted to satisfy a relocation requirement, then regular status will only apply once the employee has completed the relocation. Failure to relocate within the specified time requirements may result in termination.

ARTICLE 6 – GRIEVANCE PROCEDURE

6.1 Complaints and grievances shall be dealt with in the following manner and all grievances must be in writing and recorded within seven (7) working days of the alleged grievances.

The employee shall take the complaint up with their Supervisor verbally. Failing satisfactory settlement, the employee shall proceed to Step 1.

6.2 **Step 1**

The employee, accompanied by a Steward, shall take the grievance up with the Supervisor. Failing settlement within five (5) working days the Union may proceed to Step 2.

Step 2

The employee, within five (5) working days of the reply of Step 1, accompanied by a Steward, may take the matter up with the President. Failing settlement within five (5) working days the Union may proceed to Step 3.

Step 3

Within five (5) working days of the reply to Step 2, the employee, accompanied by the Steward and/or a Representative of the Union, may take the matter up with the President, at which time any or all of the people concerned may be present. Failing a settlement at this level within seven (7) working days, the grievance may then be referred to Article 7 of this Agreement.

ARTICLE 7 – PROVISION FOR ARBITRATION

7.1 Failing settlement at Step 3, any difference of opinion involving the interpretation or application of this Agreement may be submitted to arbitration.

7.2 When either party requests that a question be submitted to arbitration, it shall make such request in writing to the other party and at the same time inform the other party that it is the first party's intention to do so after five (5) working days. If no request for arbitration is received within ten (10) working days after the decision rendered at Step 3 is given, it shall be deemed to be abandoned or settled.

7.3 Along with the request for arbitration the party requesting shall submit either the name of a nominee to an arbitration board or a list of selections for a sole arbitrator. Should the parties or their nominees fail to agree on an arbitrator, the matter will be referred to the Ministry of Labour.

7.4 The decision of the arbitrator shall be final and binding on both parties.

7.5 No arbitrator or arbitration board shall have the power to alter or change any of the provisions of this Agreement or substitute any new provision for any existing provision or to provide a decision which is inconsistent with any provision of this Agreement.

7.6 Each party to this Agreement will bear the expense and fee of its nominee, and the parties will share equally the expenses and fee of the arbitrator or arbitration board chairman.

ARTICLE 8 – MANAGEMENT AND EMPLOYEE RESPONSIBILITIES

8.1 It is recognized that LUSI provides service for the safety, health, comfort and general welfare of the citizens. Therefore, the employee must be prepared at all hours of the day or night to assist in providing the many services and agree this complies with consent for overtime required by S20(3) of the Employment Standards Act.

8.2 The responsibility of providing the services to our customers is mutual to both LUSI and the employees and necessitates that any difference of opinion of the interpretation of the terms of this Agreement will be settled in an orderly manner in accordance with Article 6 and 7. There shall be no strikes or lockouts so long as this Agreement continues to operate. The definition of a strike or lockout is as dictated by the Ontario Labour Relations Act.

ARTICLE 9 – HOURS OF WORK

9.1 The following shall be considered straight time or regular hours.

(a) **Summer Hours**
The period from the first Monday in May to the first Friday in November, the following shall be considered straight time or regular hours:

Outside Employees
40 hours per week
Monday to Thursday 7:00 a.m. to 4:30 p.m.
with ½ hour lunch
Friday 7:00 a.m. to 11:00 a.m.

The Union acknowledges that regularly scheduled staff may perform work from 11:00 a.m. to 4:30 p.m. on Fridays.

Outside employees refers to the categories, as contained in the Hourly Rates Schedule, Electric Department, Water Treatment & Distribution Departments and the Electric and Water Departments Combined.

Water Treatment Plant Employees – Afternoon Shift (if required by management)
40 hours per week
Monday to Thursday 4:00 p.m. to 12:30 a.m.
Friday 10:30 a.m. to 3:00 p.m.
with ½ hour lunch.

(b) **Winter Hours**
The period excluding that referred to in 9.1 (a), the following shall be considered straight time or regular hours:
Outside Employees
40 hours per week
Monday to Friday 8:00 a.m. to 4:30 p.m.
With ½ hour lunch

Water Treatment Plant Employees – Afternoon Shift (if required by management)
40 hours per week
Monday to Friday 4:00 p.m. to 12:30 a.m.
With ½ hour lunch

(c) **Office Employees**
Customer Service Representatives
33 ¾ hours per week with ¾ hour lunch

Monday to Friday between the hours of (as per schedule) 8:30 a.m. to 4:30 p.m.

9.2 **Overtime**
All time worked outside the regular or normal hours as set forth in the Agreement will be classed as overtime and paid at double time except the hours between normal quitting time and 6:00 p.m. Monday to Friday, which will be paid at time and one-half.

9.3 **Banked Overtime**
Employees will be allowed to bank time off in lieu of overtime payment. In such cases, an employee may elect to bank one (1) hour off with pay for each hour paid outside of normal scheduled hours of work. A cap of forty (40) hours will apply to the overtime bank.

Time off will be given on an hour-for-hour basis from the overtime bank at a mutually agreed upon time. All requests for time off in lieu of pay for banked overtime are granted at the discretion of the supervisor. The supervisor will make every attempt to grant requests that do not place a burden on the department to complete scheduled work assignments or interfere with other schedules.

Vacation requests will take priority over the use of banked-time. Banked hours will not be carried forward. All hours remaining in an employee's overtime bank on November 30th will be paid out prior to the end of the year at the employee's regular rate.

9.4 **On-Call**

(a) A Journeyman Lineman, a Water Distribution Employee and a Water Treatment Plant Employee will be required to perform on-call duty as determined by Management.

(b) The normal on-call schedule for outside employees and Water Treatment Plant employees shall be from quitting time on Friday to start time the following Friday. If Friday is a Statutory Holiday, on-call will commence at the normal start time on Friday. On any subsequent calls during the following week they are to be called first.

(c) Qualified employees will be informed in advance of their scheduled on-call; it will be distributed on as equitable a basis as possible.

(d) The on-call person may call another person for assistance as they deem necessary.

(e) The daily on-call allowance shall be:

	2014	2015	2016
Weekday	$26	$27	$28
Weekend & Statutory Holidays	$51	$52	$53

(f) The Water Treatment Plant employee that is on-call will be required to check the Plant once per day on Saturdays, Sundays and Statutory Holidays. A weekend maintenance schedule to be performed by the on-call employee for which he will receive one and one-half (1 ½) hours at double time per day.

When the Water Treatment Plant operates on a single daily shift, the on-call allowance will be in accordance with the electric and water distribution department on-call rates.

9.5 **Minimum Call Out**

When employees are called to perform emergency response, they will be allowed a minimum of two (2) hours at the appropriate premium rate except that more than one call within two (2) hours from the start of the previous call, shall be considered as continuous time.

9.6 **Meal Allowance**

When an employee is required to work overtime, the employer will provide a meal allowance of twelve ($12.00) Dollars. Meal allowances will be provided (not including scheduled overtime) as follows:

(a) When called out on emergency work when the duration of the time worked is five (5) consecutive hours, and every four (4) hours thereafter, exclusive of meal breaks, or one (1) hour before normal start time.

(b) When working past normal quitting time, after performing a normal day's work and the duration of the time worked is three (3) hours, and every four (4) hours thereafter.

9.7 **Shift Differential**

When employees are required to work shifts, a shift differential of $0.80 per hour shall be paid. The employer reserves the right to implement an 11:00 p.m. to 7:00 a.m. shift provided the employee receives 48 hours notice of the implementation of the shift.

ARTICLE 10 – PAID HOLIDAYS

10.1 The following holidays are recognized as time off with pay for all employees:

New Year's Day
Family Day (3rd Monday of February)
Good Friday
Easter Monday
Victoria Day
Canada Day
Civic Holiday
Labour Day
Thanksgiving Day
Half working day before Christmas
Christmas Day
Boxing Day
Half working day before New Years
Any other day proclaimed by Federal, Ontario or Municipal Government

When one of the above listed holidays falls on a Saturday or Sunday, the following Monday will be observed as the holiday.

10.2 All employees must work the regular day preceding and the next regular day following any of the Paid Holidays listed in Article 10.1 to receive pay for the holiday, unless pre-arranged with Management.

10.3 Regular employees will be allowed one floating holiday per year to be taken at a time mutually agreeable between the employee and his/her supervisor.

ARTICLE 11 – VACATION ENTITLEMENT

11.1 (a) Employees with less than one (1) year of service shall receive one (1) day for each month of service, to be taken in that calendar year, to a maximum of ten (10) days.

(b) In the year that an employee completes one (1) year of service, the employee shall be entitled to ten (10) days vacation, to be taken in that calendar year.

(c) In the year that an employee completes four (4) years of service, the employee shall be entitled to fifteen (15) days vacation, to be taken in that calendar year.

(d) In the year than an employee completes ten (10) years of service, the employee shall be entitled to twenty (20) days vacation, to be taken in that calendar year.

(e) In the year that an employee completes seventeen (17) years of service, the employee shall be entitled to twenty-five (25) days vacation, to be taken in that calendar year.

(f) In the year that an employee completes twenty-eight (28) years of service, the employee shall be entitled to thirty (30) days vacation, to be taken in that calendar year.

11.2 The minimum vacation allowed will be in 2 hour increments.

11.3 Vacation shall be arranged by Management and the employee.

11.4 Annual Vacation Days for the previous calendar year shall be taken by March 31st of the following year.

11.5 For the purposes of calculating vacation time, the following shall apply:

(a) Outside employees (40 hour work week), 8 hours will represent 1 day.

(b) Inside employees (33 ¾ hour work week), 6 ¾ hours will represent 1 day.

(c) Vacation is earned in the same year that it is taken.

11.6 An employee's vacation pay will be reduced on a pro rata basis if:

(a) Absent without pay for a period exceeding twenty (20) working days in the vacation accumulation period.

(c) The employee has left LUSI's service.

ARTICLE 12 – SICK LEAVE PLAN

12.1 LUSI shall have the right at any time, after three (3) consecutive working days of illness, to have an employee claiming sick pay produce a Doctor's Certification of Illness attesting to the nature of the illness or injury, the course of treatment and the prognosis for recovery.

The employer will reimburse the employee for the cost of a medical certificate, up to twenty ($20) dollars, if requested by Management.

12.2 Sick Leave benefits are not payable to an employee who refuses to authorize disclosure to the insurers of any medical information required under this Collective Agreement.

12.3 Any employee who, because of illness or injury, is unable to report for work must notify LUSI by normal starting time.

12.4 The Sick Leave Plan will provide coverage during periods of illness or injury as follows:

(a) Short Term Coverage – Periods of less than one hundred and nineteen (119) consecutive calendar days.

(b) Long Term Coverage – Periods in excess of one hundred and nineteen (119) consecutive calendar days.

12.5 **Short Term Sick Leave**
Short Term Sick Leave pay for regular employees for each occurrence of illness or injury, including illness resulting from pregnancy, childbirth, miscarriage or abortion is:

a) Regular Employees Hired After January 31st, 2014
The accumulation of employee's sick leave will be at the rate of 1 day per month for each month of service commencing with the first full month of service and continuing to the final month of service, provided the employee works 15 or more days in the final month. Sick leave credits will cap at 85 work days (119 calendar days).

Where an employee has not accumulated 85 days of 100% paid sick leave, the difference between the accumulated 100% days and the maximum of 85 days, shall be paid at 67% of earnings.

Employees will not accumulate sick leave if absent from work for 1 calendar month or more except in the case of pregnancy/parental leave.

b) **Regular Employees Hired Prior to February 1st, 2014**

	Length of Service	**Income Security Benefits**
(i)	Less than 3 months	Up to 17 weeks 75% of normal straight time wage rate
(ii)	3 months but less than 1 year	2 weeks full salary Next 15 weeks 75% of normal straight time Wage rate
(iii)	1 year but less than 2 years	4 weeks full salary Next 13 weeks 75% of normal straight time wage rate
(iv)	2 years but less than 3 years	8 weeks full salary Next 9 weeks 75% of normal straight time wage rate
(v)	3 years but less than 4 years	12 weeks full salary Next 5 weeks 75% of normal straight time wage rate
(vi)	4 years but less than 5 years	16 weeks full salary Next 1 week 75% of normal straight time wage rate
(vii)	5 years and over	17 weeks full salary 100% of normal straight time wage rate

(viii)	If the disability is new, full benefits must be reinstated no later than one (1) month after the employee returns to work.
(ix)	If the disability is a recurrence of an earlier one, full benefits must be reinstated no later than three (3) months after the employee returns to work.

12.6 Long Term Disability

(a) Benefits in the long term for regular employees are those provided under the Long Term Disability Plan in Article 12.4 (b) of this Agreement and begin after the one hundred and nineteenth (119th) day of illness at which time the Insurance Carrier shall maintain payments in the amount of the long term disability coverage at sixty-six and two-thirds (66 2/3%) percent of normal straight time monthly earnings up to a maximum of Four Thousand ($4,000) Dollars per month until the employee reaches age sixty-five (65). Long Term Disability payments will not be paid to an employee on Worker's Compensation.

(b) For a period of time not to exceed twenty-four (24) months from the first day of non-occupational sickness or injury, the employee shall be eligible to return to the same job if capable of performing the required work. If unable to perform the required work, the employee shall be given all reasonable consideration for any available job for which the employee is able and qualified to perform.

12.7 Workplace Safety and Insurance Board (WSIB)

When an employee, through his/her paid employment by the Board, suffers an illness or injury which is compensable under the Workplace Safety and Insurance Act, the employee will receive payment in accordance with the Act.

For a period of time not to exceed twenty-four (24) months, only those employees on leave covered by the Workplace Safety and Insurance Board shall be given consideration for any job, if available, and if the employee is capable and qualified to perform.

12.8 General Conditions for Sick Leave Coverage

(a) After the one hundred and nineteenth (119th) day of illness or injury an employee's vacation or recognized holiday shall be paid and prorated only on the basis of time worked.

(b) LUSI shall continue to pay, for a period of time not to exceed twelve (12) months from the first day of sickness or injury, the premiums for benefits in Article 13 and Article 14 of this Agreement. After the twelve month period, employees on disability shall be entitled to pay the full cost of premiums in order to continue on the group plan for a further twelve months.

(c) In consideration of the benefits granted by LUSI, the employees agree to make no claim against any savings in UIC premiums resulting from the Sick Leave Plan.

ARTICLE 13 – HEALTH INSURANCE PLAN

13.1 LUSI agrees to pay for all regular and probationary employees one hundred (100%) percent of the premium cost of the Sun Life Insurance Semi Private Plan and the Sun Life Insurance Extended Health Care Plan ($25 per employee, family coverage, deductible per year). Coverage shall commence after the normal notification of the Carrier.

13.2 Included in the extended health care plan:

- (a) **Chiropractic Plan** up to a maximum of $500 per calendar year.
- (b) **Naturopath** coverage up to a maximum of $500 per calendar year.
- (c) **Massage Therapist** coverage up to a maximum of $500 per calendar year.

13.3 LUSI agrees to pay one hundred (100%) percent of the premium cost of the Sun Life Insurance **Vision Care Plan** to a maximum coverage of three hundred and fifty ($350) dollars every two years for adults, three hundred ($300) dollars every twelve (12) months for children under eighteen (18) years of age.

The employer will increase **eye exam coverage** from fifty ($50) dollars to one hundred ($100) dollars per family member. The employer has the option of self-insuring the increased benefit.

13.4 LUSI agrees to pay one hundred (100%) percent of the premium cost of the Sun Life Insurance **Dental Plan,** including 50% reimbursement of the initial cost of dentures, based on the current ODA rates for all regular and probationary employees in receipt of normal straight time wage rates from LUSI. Dental Recall Examination coverage every 9 months.

13.5 LUSI agrees to pay one hundred (100%) percent of the premium cost of the Sun Life Insurance **Orthodontics Plan** to a maximum of two thousand five hundred ($2500) dollars Lifetime, fifty (50%) percent co-insurance. Management has the option of self-administering the orthodontic benefit.

13.6 LUSI agrees to pay these benefits for all regular and probationary employees in receipt of normal base pay from LUSI. Should Lakefront change to another benefit provider during the life of this collective agreement, every effort will be made to mirror existing benefits provided on date of ratification.

13.7 In the event of the death of an active employee, who is in receipt of benefits, the employee's current spouse and dependants will continue to have the above employee health benefits and dental coverage for a maximum of twelve (12) months or age sixty-five (65) or until they remarry, whichever comes first.

13.8 The Employer agrees to co-share (50/50), with the employee, the cost of the income tax payroll deduction for the Ontario Health Premium.

13.9 Benefits for Retirees

- a) Employees who retire on a reduced pension between the ages of fifty-five (55) and sixty-five (65), may continue to participate in the Group Extended Health Benefits Plan upon payment to Lakefront Utility Services Inc. the full cost of the billed premium applicable to each employee providing only that the employee is eligible to participate in such plan or plans.

b) Lakefront will provide an option to all employees who retire on an unreduced pension from the Ontario Municipal Employees Retirement System to the age of sixty-five (65) years to continue Group Extended Health Benefits Plan for the employee, at Lakefront's cost providing the employee is eligible to participate in the plans.

c) In the event of a death of a retiree, prior to age 65, the retiree's spouse (and any applicable dependents) may remain on the benefit plan until the retiree would have attained the age of 65, however, they will be responsible for the full cost of the 'Retiree Benefit Coverage'.

Note: This Extended Health Coverage does not include "Out of Province" coverage.

ARTICLE 14 – LIFE INSURANCE

14.1 All regular employees will continue to be enrolled in LUSI's insurance plan for which LUSI pays one hundred (100%) percent of the premiums for coverage up to one and one-half (1 ½) times salary in accordance with the terms of the policy in force.

14.2 Employees will be able to take advantage of the insurance options offered under the life insurance program. LUSI will pay for the basic coverage, as defined in the plan, and the employee will be responsible for the cost of the optional insurance, which will be deducted through payroll.

ARTICLE 15 – OMERS PENSION

15.1 All regular and probationary employees will participate in the Ontario Municipal Employees Retirement System (OMERS) basic pension plan in accordance with the OMERS regulations.

ARTICLE 16 – SENIORITY AND PROMOTION

16.1 Seniority shall be given special consideration in making promotions, layoffs, or re-employment, providing the qualifications and ability are satisfactory to Management. Subject to grievance procedure.

16.2 When a vacancy occurs within the bargaining unit it shall be posted for a period of seven (7) calendar days on the bulletin board(s) in order to give employees an opportunity to make an application for the position. The job posting will contain a job classification, required education, skills, hours of work, job requirements, and rate of pay.

16.3 Management shall not be precluded from selecting a candidate from outside the existing bargaining unit if no employee(s) have the necessary qualifications, skills and ability to perform the job. The name(s) of the successful applicant(s) shall be posted on the designated bulletin boards for five (5) calendar days.

16.4 When employees are promoted they shall receive a trial period not exceeding two (2) months during which time they may return or be returned to their former job.

16.5 Progression in the line, meter and water classifications are not automatic but based on the successful completion of the Electricity Distributors Association/Electricity & Utility Safety Association Lineman Certification or the successful completion of the appropriate Ontario Ministry of the Environment Water Certificate.

16.6 Seniority shall commence from the date the employee last entered the employ of LUSI as a probationary employee. Temporary employees shall not accumulate seniority.

16.7 An employee shall lose seniority and shall cease to be an employee if he or she:

(a) Quits voluntarily or is discharged and such discharge is not reversed by the grievance arbitration procedure;

(b) Retires;

(c) Fails to report for work after a layoff within seven (7) working days of recall, notice of which has been mailed by registered mail to the last address of which LUSI was notified by the employee; an employee shall have his or her seniority frozen if laid off;

(d) Is absent from work because of occupational or non-occupational illness or injury for twenty-four (24) months.

16.8 **Layoff and Recall**
Layoff will be in reverse order of seniority provided the employees retained have the skill and ability to perform the remaining jobs. Recall will be in reverse order of layoff provided the employees recalled have the skill and ability to do the required work.

Employees will receive layoff notice in accordance with the current Employment Standards Act.

16.9 Management has the option to credit a new employee with a portion of the employee's previous relevant experience with respect to calculating vacation entitlement only.

ARTICLE 17 – RELIEF PAY

17.1 **Outside**
When an outside regular employee is relieving in a higher grade for a period of more than one (1) working day upon instructions from Management he/she shall receive the rate for that classification for all time so worked.

17.2 **Office**
When a regular office employee is relieving in a higher classification for a period of one (1) working day or more, upon instruction from Management, the employee shall receive the rate for that classification for all time so worked.

17.3 **Acting Supervisor**
When an employee is assigned by Management to an Acting Supervisor or Non-Union Position, for a period of one (1) working day or more, upon instruction from Management, he/she shall receive a rate of pay ten (10%) percent higher than the employee's regular rate.

ARTICLE 18 – LEAVE OF ABSENCE

18.1 **Union Consultation**
Leave of absence with pay will be granted to representatives of the Union while in consultation with LUSI on matters pertaining to the agreement during working hours.

18.2 **Union Functions**

Upon request of the Union, LUSI agrees to allow leave of absence without pay or loss of seniority to members for Union functions, provided that the leave concerned does not exceed ten (10) days. LUSI may grant a leave of absence to any employee for any reasonable request, without pay.

Such request shall be in writing two (2) weeks prior to the leave of absence if possible. Any leave of absence granted by LUSI shall be in writing. Any employee granted leave of absence shall not lose his/her seniority rights.

18.3 **Maternity, Paternity & Adoption Leave**

" As per Employment Standards Act"

18.4 **Bereavement**

(a) An employee will be allowed five (5) days off with pay when a death occurs in the employee's immediate family. Immediate family means current spouse, common-law spouse, child or stepchild.

(b) An employee will be allowed three (3) days off with pay in the event of the death of a parent, current spouse's parent, sister, brother, grandchild, current son-in-law or current daughter-in-law.

(c) An employee will be allowed one (1) day with pay, to regular employees, in the event of the death of a grandparent, current grandparent-in-law, current sister-in-law or current brother-in-law, for the purpose of attending the funeral on a scheduled work day.

18.5 **Jury or Court Witness Duty**

The employer shall grant leave of absence without loss of seniority to an employee who serves as a juror or witness in any court. The employer shall pay such an employee the difference between his/her normal earnings and the payment he/she receives for jury service or court witness, excluding payment for traveling, meals, or other expenses. The employee will present proof of service and the amount of pay received.

18.6 **Compassionate Leave**

Employees within the Customer Service Representative classification shall be entitled, with pay, up to two days annually for Compassionate Leave which can be taken in increments up to the two day allotment to address personal emergencies, involving their immediate family or parents.

ARTICLE 19 – ALLOWANCES

19.1 LUSI will provide all tools and equipment necessary to carry out the work of LUSI, each employee whose duties call for the same will be issued with tools and equipment to enable satisfactory working conditions.

Each employee will use the tools and equipment in a safe and proper manner and will provide proper care for these tools.

19.2 All regular full time employees (as referred to in Article 5.3) will be eligible to receive the following clothing and footwear allowance as outlined for their department.

LUSI will contribute, per contract year, toward the replacement of CSA approved appropriate safety footwear (including green patch and/or OHM rating), for applicable employees. Employees will be reimbursed upon the presentation of a properly dated receipt evidencing the purchase of new safety footwear. The employee, in accepting this safety footwear allowance, agrees to wear approved safety footwear (in good condition) during all working hours.

LUSI will provide rubber safety footwear for the Linemen, Water Distribution and Water Treatment Operators as required and will be replaced on an exchange basis.

Employees will be allowed to carry forward any unused boot allowance (to a maximum of one (1) year's boot allowance) to the following year.

Reimbursement by employee category will be as follows:

	2014	2015	2016
Electric Distribution	$235.00	$240.00	$245.00
Water Distribution	$235.00	$240.00	$245.00
Others	$205.00	$210.00	$215.00

LUSI will contribute, per contract year, toward the purchase of approved appropriate safety clothing for each applicable employee. The employee, in accepting this safety clothing allowance, agrees to wear approved safety clothing (in good condition) as required.

	2014	2015	2016
Electric Distribution	$610.00	$620.00	$630.00
Water Distribution/Metering	$360.00	$370.00	$380.00

19.3 LUSI will provide an annual allowance of One Hundred ($100.00) Dollars to the Office Staff for the purchase of suitable clothing.

19.4 LUSI will supply protective equipment for use against live conductors, including rubber gloves, line hose and rubber blankets.

19.5 Safety hats and safety equipment provided by LUSI shall be worn and used during working hours by employees that have been issued such equipment. Failure to comply with these regulations, the employee shall be subject to disciplinary action as the Management and LUSI see fit.

19.6 The current accident prevention rule book E&USA and such other safety rules as Management may stipulate from time to time shall be observed by all employees.

19.7 LUSI will supply the Stockkeeper with a shop coat.

19.8 Water Treatment Plant Employees will be issued two (2) pair (non-orange work-wear) coveralls and replaced on an as-needed basis.

Information Note: Each employee presently has been issued one (1) pair.

ARTICLE 20 – UNION COMMITTEE & STEWARDS

20.1 LUSI acknowledges the right of the Union to appoint or otherwise select Committees and Stewards in accordance with the selections of this Article. The Union shall advise the Management of the personnel serving on these Committees and also the names of the Stewards.

LUSI will recognize a Negotiating Committee comprised of five (5) union representatives as follows:

1 – CUPE National Representative
1 – Local CUPE Executive Representative (President/Vice-President)
1 – Representative each from Electric, Water and Office for a 2-day period.
If negotiations continue beyond the second day, the Union will incur the cost of the 4th local representative, or choose to have one less committee member.

20.2 The Union acknowledges that Stewards, members of the Committee and Union Officers have regular duties to perform on behalf of LUSI. Such persons shall not leave their regular duties without receiving permission from their Supervisor and such permission shall not be unreasonably withheld.

When resuming their regular duties they shall report to their Supervisor.

It is clearly understood that Stewards and other Union Officials shall not absent themselves from their regular duties unreasonably in order to deal with the grievances of employees up to but not including arbitration. In accordance with this, the Management shall not make any pay deduction from such employees for the time spent in handling grievances and meetings with Management. This does not apply to the time spent on such matters outside regular working hours.

20.3 Notwithstanding the above, it is understood in the absence of a water, electric and/or office representative, the Union shall appoint or elect a replacement representative.

20.4 **Joint Employee Relations Committee**
Management and the Union recognize the importance of maintaining employee and employer relations and to that end agree to participate in semi-annual meetings, or as may be required from time to time, to discuss matters of mutual interest to improve their relationship. The Committee shall consist of the President and Corporate Secretary, representing Management, and the CUPE Local Executive Member (President/Vice-President) and the Union Steward, representing the Union.

ARTICLE 21 – GENERAL

21.1 **Inclement Weather**
LUSI will provide alternative work, for employees who usually work outside during inclement weather. Inclement weather will be determined by Management.

When it is necessary for employees to work in inclement weather, Management will provide suitable rainwear.

21.2 **Alcoholic Beverages**
It is the policy of LUSI that no employee will use alcoholic beverages during working hours. Failure to observe this policy will result in disciplinary action up to and including discharge.

21.3 **Time of Pay**
Employees will be paid by direct bank deposit every two weeks on Thursday, before noon, except in circumstances beyond the control of LUSI.

ARTICLE 22 – CLASSIFICATION AND WAGE SCHEDULE

22.1 Electric Department

A) Journeyman Lineman	100% of Journeyman Lineman Rate
Learner Lineman 'A'	Fourth 2000 hours of service–90% of Journeyman Lineman Rate
Learner Lineman 'B'	Third 2000 hours of service–85% of Journeyman Lineman Rate
Learner Lineman 'C'	Second 2000 hours of service-80% of Journeyman Lineman Rate
Learner Lineman 'D'	First 2000 hours of service-70% of Journeyman Lineman Rate

Progressions are not automatic to the **full Journeyman Lineman** rate but are based on the successful completion of the 8000 hours and the Infrastructure Health & Safety Association Training Program.

B) Distribution Technician	100% of Distribution Technician Rate
3rd Year	90% of Distribution Technician Rate
2nd Year	80% of Distribution Technician Rate
1st Year	70% of Distribution Technician Rate

Progressions are not automatic to the **full Distribution Technician** rate but are based on annual performance evaluations that indicate continued development in the position.

22.2 Office Employees

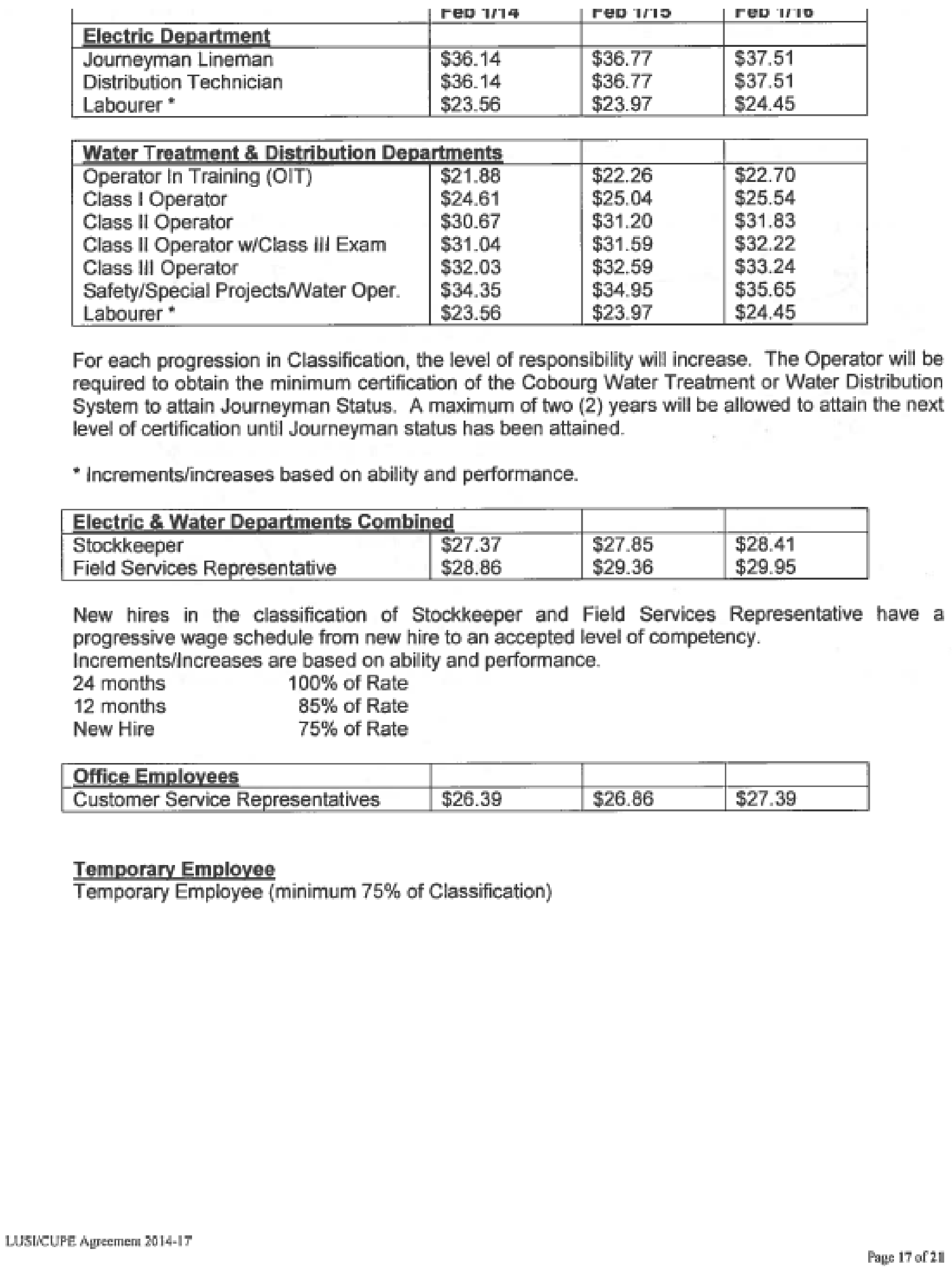
New Hires in the classification of Customer Service Representative will have a progressive wage schedule from new hire to an accepted level of competency:

24 months	100% of Rate
18 months	90% of Rate
12 months	80% of Rate
6 months	70% of Rate
New Hire	60% of Rate

* Increments/Increases are based on ability and performance.

22.3 General Wage Increase

February 1st, 20114	1.75%
February 1st, 2015	1.75%
February 1st, 2016	2.00%



	Feb 1/14	Feb 1/15	Feb 1/16
Electric Department			
Journeyman Lineman	$36.14	$36.77	$37.51
Distribution Technician	$36.14	$36.77	$37.51
Labourer *	$23.56	$23.97	$24.45

Water Treatment & Distribution Departments			
Operator In Training (OIT)	$21.88	$22.26	$22.70
Class I Operator	$24.61	$25.04	$25.54
Class II Operator	$30.67	$31.20	$31.83
Class II Operator w/Class III Exam	$31.04	$31.59	$32.22
Class III Operator	$32.03	$32.59	$33.24
Safety/Special Projects/Water Oper.	$34.35	$34.95	$35.65
Labourer *	$23.56	$23.97	$24.45

For each progression in Classification, the level of responsibility will increase. The Operator will be required to obtain the minimum certification of the Cobourg Water Treatment or Water Distribution System to attain Journeyman Status. A maximum of two (2) years will be allowed to attain the next level of certification until Journeyman status has been attained.

* Increments/increases based on ability and performance.

Electric & Water Departments Combined			
Stockkeeper	$27.37	$27.85	$28.41
Field Services Representative	$28.86	$29.36	$29.95

New hires in the classification of Stockkeeper and Field Services Representative have a progressive wage schedule from new hire to an accepted level of competency.
Increments/Increases are based on ability and performance.

24 months	100% of Rate
12 months	85% of Rate
New Hire	75% of Rate

Office Employees			
Customer Service Representatives	$26.39	$26.86	$27.39

Temporary Employee
Temporary Employee (minimum 75% of Classification)

ARTICLE 23 – TERM OF AGREEMENT

23.1 This agreement shall be operative for a period of three (3) years dating from February 1st, 2014 and expiring January 31st, 2017

Dated at Cobourg, Ontario this 22 day of DECEMBER 2014

Signed on behalf of LUSI

Dereck C. Paul
President

Susan Spicer
Director of HR

Tara Storey

Tara Storey
HR Generalist

Don MacMaster
HR Consultant

Signed on behalf of the Union

Garth Beer.

Garth Beer
Vice-President

Tim Clarey
Bargaining Committee Representative

Dwayne Northup
Bargaining Committee Representative

Susan O'Neil

Susan O'Neil
Bargaining Committee Representative

Betty Sommers

Betty Sommers
CUPE National Representative

LETTER OF UNDERSTANDING – SHIFT DIFFERENTIAL

Re: Article 9.7 Shift Differential

For further clarification of Article 9.7 and its reference to LUSI's right to implement an 11:00 p.m. to 7:00 a.m. shift, it is the intent of LUSI to not use this clause as a vehicle by which to implement a regular shift. LUSI will only invoke this clause if it is necessary under emergency or unusual circumstances.

Should LUSI implement an 11:00 p.m. to 7:00 a.m. shift, the person on-call would continue to perform on-call services as may be required from time to time during this time period.

Dated at Cobourg, Ontario this 22nd day of September, 2010.

Signed on behalf of LUSI

Bruce R. Craig
President

Susan Spicer
Corporate Secretary

Signed on behalf of the Union

Garth Beer
Garth Beer
Vice-President

Jim McCrory
Bargaining Committee Representative

Dwayne
Dwayne Northup
Bargaining Committee Representative

Susan
Susan O'Neil
Bargaining Committee Representative

Betty Sommers
Betty Sommers
CUPE National Representative

LETTER OF UNDERSTANDING – WSIB CLAIMS

LUSI, in an effort to assist employees in their time of need, agrees to provide to an employee who is establishing a claim under the Workers' Compensation Insurance Board (WSIB), bridge payments until the WSIB claim has been established and payment has been received by the employee. The employee, upon receiving payments from the WSIB, will reimburse the employer the amount of the bridge payments received from LUSI.

Dated at Cobourg, Ontario this 22ND day of SEPTEMBER, 2010.

Signed on behalf of LUSI

Bruce R. Craig
President

Susan Spicer
Corporate Secretary

Signed on behalf of the Union

Garth Beer

Garth Beer
Vice-President

Jim McCrory
Bargaining Committee Representative

Dwayne North

Dwayne Northup
Bargaining Committee Representative

Susan O'Neil

Susan O'Neil
Bargaining Committee Representative

Betty Sommers

Betty Sommers
CUPE National Representative

LETTER OF UNDERSTANDING – CROSS-TRAINING HOURLY RATE ADDERS

The following people have an 'adder' to their rate as detailed below:

Employee	**Hourly Adder**	**Qualification**
Earl McGinn	$ .30	Class 1 WT Exam
Tim Clarey	$ .60	Class 1 WT Exam & Class 1 WT Certification

Dated at Cobourg, Ontario this 22 day of DECEMBER, 2014.

Signed on behalf of LUSI

Dereck C. Paul
President

Susan Spicer
Director of HR

Tara Storey

Tara Storey
HR Generalist

Don MacMaster
HR Consultant

Signed on behalf of the Union

Garth Beer

Garth Beer
Vice-President

Tim Clarey
Bargaining Committee Representative

Dwayne Northup
Bargaining Committee Representative

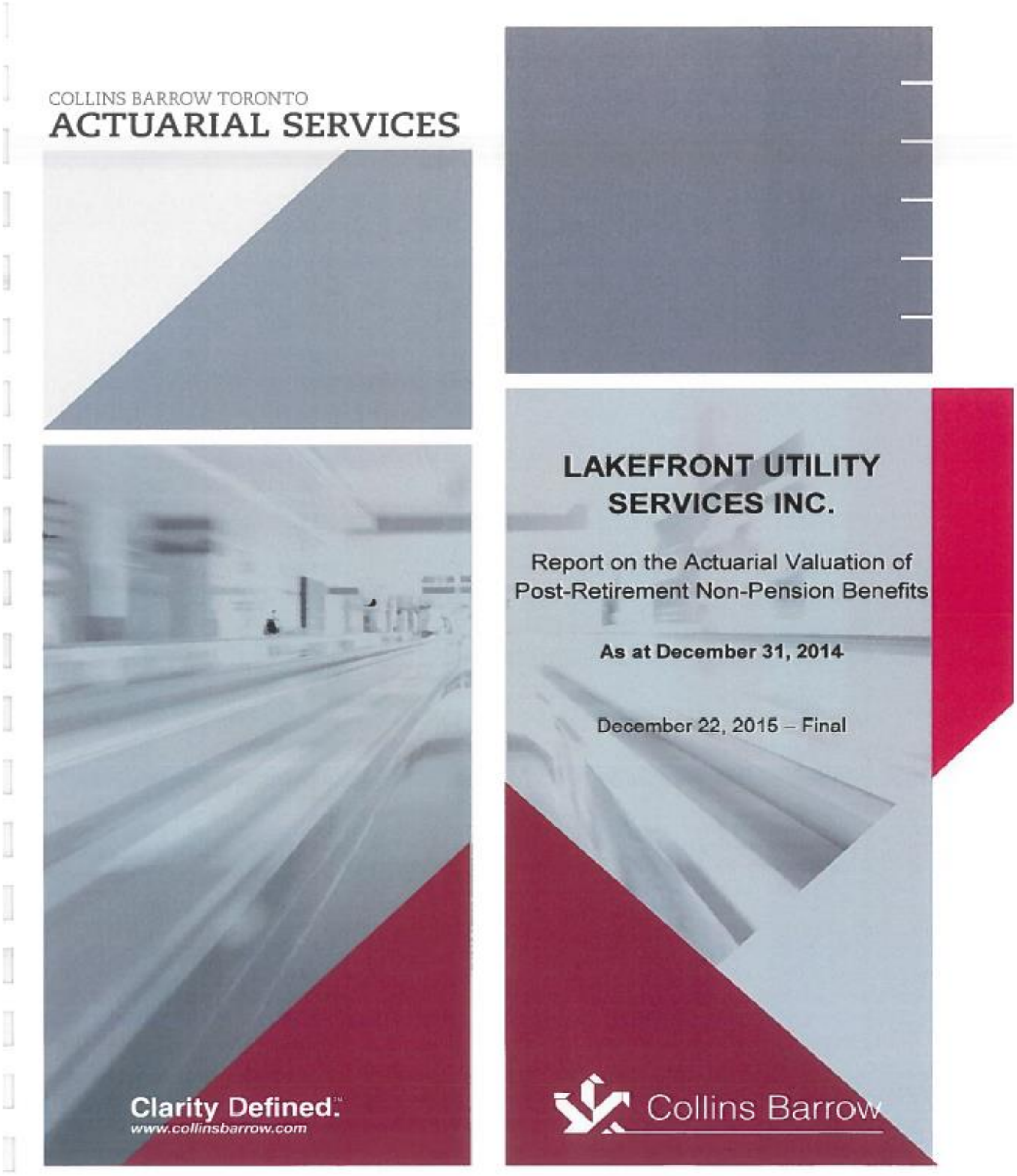
Susan O'Neil

Susan O'Neil
Bargaining Committee Representative

Betty Sommers

Betty Sommers
CUPE National Representative

Attachment B - LUI Actuarial Agreement



COLLINS BARROW TORONTO
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LAKEFRONT UTILITY SERVICES INC.

Report on the Actuarial Valuation of
Post-Retirement Non-Pension Benefits

As at December 31, 2014

December 22, 2015 – Final

Collins Barrow

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TABLE OF CONTENTS

EXECUTIVE SUMMARY

PURPOSE

Collins Barrow Toronto Actuarial Services Inc. was engaged by Lakefront Utility Services Inc. (the "Corporation") to perform an actuarial valuation of the post-retirement non-pension benefits sponsored by the Corporation and to determine the accounting results for those benefits for the fiscal period ending December 31, 2014. The nature of these benefits is defined benefit.

This report is prepared in accordance with the following standards:

1. For the Corporation's Electric division, the International Financial Reporting Standards (the "IFRS") guidelines for post-retirement non-pension benefits as outlined in the amendments to the International Accounting Standard 19 – Employee Benefits ("IAS 19") issued in June 2011.
2. For the Corporation's Water division, the Canadian Institute of Chartered Accountants (the "CICA") guidelines outlined by CICA Public Sector Accounting Recommendations Section 3250 ("PS 3250") of the CICA Handbook.

The Corporation's Electric division transitioned to reporting on the basis of IFRS for the fiscal year beginning January 1, 2015. Prior to this date, the valuation of the Corporation's post-retirement non-pension benefits for the Electric division was prepared in accordance with the CICA guidelines outlined in Employee Future Benefits, Section 3461 of the CICA Handbook-Accounting ("CICA 3461").

The previous valuation for the Corporation's Water division was done in accordance with CICA 3461 as noted in the valuation report at January 1, 2012.

The purpose of this valuation is threefold:

i) to determine the Corporation's liabilities in respect of post-retirement non-pension benefits at December 31, 2014;

ii) to determine the expense to be recognized in the income statement for fiscal year 2015; and

iii) to provide all other pertinent information necessary for compliance with IAS 19 for the Corporation's Electric division and PS 3250 for the Corporation's Water division.

The intended users of this report include the Corporation and its auditors. This report is not intended for use by the plan beneficiaries or for use in determining any funding of the benefit obligations.

1

SUMMARY OF KEY RESULTS

The key results of this actuarial valuation as at December 31, 2014 with comparative results from the previous valuation as at January 1, 2012 are shown below, broken down by Electric and Water divisions with figures in thousands of dollars:

Electric Division

	Prior Valuation at January 1, 2012 (CICA 3461)	Current Valuation at December 31, 2014 (IAS 19)
Present Value of Defined Benefit Obligation (PV DBO)		
a) People in Receipt of Benefits	166	372
b) Fully Eligible Actives	18	-
c) Not Fully Eligible Actives	133	73
Total PV DBO	**317**	**445**

	CY 2012 (CICA 3461)	CY 2015 (IAS 19)
Current Service Cost	11	11
Interest Cost	14	16
Past Service Cost	3	-
Recognition of Actuarial(Gains)/Losses	-	(20)
Defined Benefit Cost	**28**	**7**

We note that, pursuant to IAS 19 guidelines, the actuarial gain figure above of approximately $20,000 is recognized as a change in other comprehensive income in 2015. The remainder of the defined benefit cost is recognized in the income statement.

2

Water Division

	Prior Valuation at January 1, 2012 (CICA 3461)	Current Valuation at December 31, 2014 (PS 3250)
Accrued Benefit Obligation (ABO)		
a) People in Receipt of Benefits	182	273
b) Fully Eligible Actives	49	-
c) Not Fully Eligible Actives	119	82
Total ABO	**350**	**355**

	CY 2012 (CICA 3461)	CY 2015 (PS 3250)
Current Service Cost	5	8
Interest Cost	15	13
Past Service Cost	7	7
Amortization of (Gains)/Losses	(1)	(2)
Benefit Expense	**26**	**26**

ACTUARIAL CERTIFICATION

An actuarial valuation has been performed on the post-retirement non-pension benefit plans sponsored by Lakefront Utility Services Inc. (the "Corporation") as at December 31, 2014, for the purposes described in this report.

In accordance with the Canadian Institute of Actuaries Consolidated Standards of Practice General Standards, we hereby certify that, in our opinion, for the purposes stated in the Executive Summary:

1. The data on which the valuation is based is sufficient and reliable;
2. The assumptions employed, as outlined in this report, have been selected by the Corporation as management's best estimate assumptions (no provision for adverse deviations) and we express no opinion on them;
3. All known legal and constructive obligations or substantive commitments with respect to the post-retirement non-pension benefits sponsored by and identified by the Corporation are included in the calculations; and
4. This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada.

We are not aware of any subsequent events after December 31, 2014 that would have a significant effect on our valuation.

The latest date on which the next actuarial valuation should be performed is December 31, 2017. If any supplemental advice or explanation is required, please advise the undersigned.

Respectfully submitted,

COLLINS BARROW TORONTO ACTUARIAL SERVICES INC.

Stanley Caravaggio

Stanley Caravaggio, FSA FCIA
Senior Manager

Patrick G. Kavanagh

Patrick G. Kavanagh, AB ASA ACIA CERA
Senior Manager

Toronto, Ontario

December 22, 2015

SECTION A— VALUATION RESULTS FOR THE ELECTRIC DIVISION

Table A - 1 shows the key valuation results for the prior valuation and the current valuation of the Corporation's Electric division.

Table A - 2 shows the sensitivity of the valuation results to certain changes in assumptions. We have shown a change to the assumed retirement age from age 60 to 58, and an increase/decrease in the health and dental claims cost trend rates by 1% per annum.

Table A - 3 presents the reconciliation of changes in the defined benefit obligation at December 31, 2014.

VALUATION RESULTS

Table A.1—Valuation Results for the Corporation's Electric Division (in thousands of dollars)

	January 1, 2012 (CICA 3461)	December 31, 2014 (IAS 19)
Present Value of Defined Benefit Obligation (PV DBO)		
a) People in Receipt of Benefits	166	372
b) Fully Eligible Actives	18	-
c) Not Fully Eligible Actives	133	73
Total PV DBO	**317**	**445**

	CY 2012 (CICA 3461)	CY 2015 (IAS 19)
Current Service Cost	11	11
Interest Cost	14	16
Past Service Cost	3	n/a
Defined Benefit Cost Recognized in Income Statement	**28**	**27**
Net Actuarial Loss/(Gain)	n/a	(20)
Defined Benefit Cost Recognized in Other Comprehensive Income	**n/a**	**(20)**
Total Defined Benefit Cost	**28**	**7**
Expected Benefit Payments	**27**	**56**

The benefit payments for CY 2015 are based on the estimated payments to be made for those expected to be eligible for benefits.

SENSITIVITY ANALYSIS

Table A.2—Sensitivity Analysis for the Corporation's Electric Division (in thousands of dollars)

	December 31, 2014 (IAS 19)			
	Valuation Results	**Retirement Age 58**	**Cost Trends +1%**	**Cost Trends -1%**
Present Value of Defined Benefit Obligation (PV DBO)				
a) People in Receipt of Benefits	372	372	376	367
b) Fully Eligible Actives	-	-	-	-
c) Not Fully Eligible Actives	73	83	81	67
Total PV DBO	**445**	**455**	**457**	**434**

	CY 2015 (IAS 19)			
	Valuation Results	**Retirement Age 58**	**Cost Trends +1%**	**Cost Trends -1%**
Current Service Cost	10	11	12	10
Interest Cost	16	17	17	16

RECONCILIATION OF THE DEFINED BENEFIT OBLIGATION

Table A.3—Development of Changes in the Defined Benefit Obligation for the Corporation's Electric Division (in thousands of dollars)

Prepaid Benefit Liability at December 31, 2014 (CICA 3461)	294
Unrecognized (Gain)/Loss	34
Unrecognized Past Service Cost	25
Accrued Benefit Obligation at December 31, 2014 (CICA 3461)	**353**
Adjustment for Corrections in valuation methodology (see below for details)	30
Adjustment for Demographic Changes	104
Adjustment for CICA 3461 to IAS 19 calculation methodologies	(1)
Change in Assumptions at December 31, 2014	(41)
PV DBO at December 31, 2014 (IAS 19)	**445**

The adjustment to PV DBO for corrections noted above results in an addition to the liability of approximately $30,000 and reflects the correction to the calculation of the minimum service requirement for projection of future benefit eligibility. We have reflected that this amount be recognized immediately as an adjustment to the prepaid benefit liability at December 31, 2014.

Please note that after reflecting the above correction, the actual PV DBO at December 31, 2014 is approximately $62,000 higher than the expected PV DBO at December 31, 2014. This is due to a combination of the following factors:

- A change in the discount rate assumption (an increase of approximately $5,100)
- A change in the health and dental trend rate assumptions (an increase of approximately of $100)
- Difference in the liability stemming from the change in calculation methods from CICA 3461 to IAS 19 (a decrease of approximately $800)
- A change in the salary scale assumption (a decrease of approximately $1,300)
- A change in the mortality table assumption (a decrease of approximately $19,900)
- Differences between the actual and expected health and dental benefit cost rates (a decrease of approximately $25,000)
- Deviations from the expected demographic changes of the valued group (an increase of approximately $103,800)

SECTION B— VALUATION RESULTS FOR THE WATER DIVISION

Table B - 1 shows the key valuation results for the prior valuation and the current valuation of the Corporation's Water division.

Table B - 2 shows the sensitivity of the valuation results to certain changes in assumptions. We have shown a change to the assumed retirement age from age 60 to 58, and an increase/decrease in the health and dental claims cost trend rates by 1% per annum.

Table B - 3 presents the reconciliation of changes in the accrued benefit obligation at December 31, 2014.

Table B - 4 presents the amortization of past service cost in 2015

1

VALUATION RESULTS

Table B.1—Valuation Results for the Corporation's Water division
(in thousands of dollars)

	January 1, 2012 (CICA 3461)	December 31, 2014 (PS 3250)
Accrued Benefit Obligation (ABO)		
a) People in Receipt of Benefits	182	273
b) Fully Eligible Actives	49	-
c) Not Fully Eligible Actives	119	82
Total ABO	**350**	**355**

	CY 2012 (CICA 3461)	CY 2015 (PS 3250)
Current Service Cost	5	8
Interest Cost	15	13
Amortization of Past Service Cost	7	7
Amortization of (Gains)/Losses	(1)	(2)
Total Benefit Expense	**26**	**26**
Expected Benefit Payments	**31**	**51**

The benefit payments for CY 2015 are based on the estimated payments to be made for those expected to be eligible for benefits.

2

SENSITIVITY ANALYSIS

Table B.2—Sensitivity Analysis for the Corporation's Water Division (in thousands of dollars)

	December 31, 2014 (PS 3250)			
	Valuation Results	Retirement Age 58	Cost Trends +1%	Cost Trends -1%
Accrued Benefit Obligation (ABO)				
a) People in Receipt of Benefits	273	273	277	271
b) Fully Eligible Actives	-	-	-	-
c) Not Fully Eligible Actives	82	97	91	74
Total ABO	**355**	**370**	**368**	**345**

	CY 2015 (PS 3250)			
	Valuation Results	Retirement Age 58	Cost Trends +1%	Cost Trends -1%
Current Service Cost	8	9	9	7
Interest Cost	13	14	14	13

DEVELOPMENT OF CHANGES IN THE ABO

Table B.3—Development of Changes in the ABO for the Corporation's Water Division
(in thousands of dollars)

	CICA 3461	Adjustment	PS 3250
Prepaid Benefit Liability at December 31, 2014	308	-	308
Unrecognized (Gain)/Loss	(24)	(9)	(33)
Unrecognized Past Service Cost	59	(1)	58
ABO at December 31, 2014	**343**	**(10)**	**333**
Adjustment for Corrections (see below for details)			26
Adjustment for Demographic Changes			39
Change in Assumptions at December 31, 2014			(43)
Remeasured ABO at December 31, 2014			**355**

As indicated above, the change in the ABO to reflect the difference in the liability between the CICA 3461 and PS 3250 reporting standard methodologies is a decrease of approximately $9,800.

The adjustment to the ABO of $26,400 is in regards to corrections to the calculation of the minimum service requirement for projection of future benefit eligibility at retirement.

We have reflected that this amount be recognized immediately as an adjustment to the prepaid benefit liability at December 31, 2014.

Please note that after reflecting the aforementioned changes, the actual ABO at December 31, 2014 is approximately $4,000 lower which is due to a combination of the following factors:

- A change in the discount rate assumption (an increase of approximately $4,200)
- A change in the health and dental trend rate assumptions (a decrease of approximately of $600)
- A change in the salary scale assumption (a decrease of approximately $900)
- A change in the mortality table assumption (a decrease of approximately $16,500)
- Differences between the actual and expected health and dental benefit cost rates (a decrease of approximately $29,600)
- Deviations from the expected demographic changes of the valued group resulting in decrement gain/loss (an increase of approximately $39,400)

1

AMORTIZATION OF PAST SERVICE COST

Table B.4—Amortization of Past Service Cost for the Corporation's Water Division (in thousands of dollars)

	CICA 3461	Adjustment	PS 3250
Total Past Service Cost at January 1	59	(1)	58
Amortization for Current Year in 2015	(7)	-	(7)
Unamortized Past Service Cost at December 31	**52**	**(1)**	**51**

Effective February 1, 2010, the post-retirement health and dental cost-sharing basis between the Corporation and its employees was removed, leaving the full cost of the benefits to be paid by the Corporation. This resulted in a past service liability of $112,002 at January 1, 2012. The remaining amount to be amortized as at December 31, 2014 was approximately $59,000 on the basis of the CICA 3461. The corresponding change in the past service liability when revalued under CICA PS 3250 basis is reduced by about $1,000 as indicated in the table above.

Pursuant to CICA PS 3250, the past service liability is amortized on a straight-line basis over the expected average remaining service period (EARSL) of employees expected to receive benefits. The actual amortization for the year 2015 is approximately $7,000.

2

SECTION C—
PLAN PARTICIPANTS

Table C – 1 sets out the summary information with respect to the plan participants valued in the report, along with comparisons to the participants in the previous valuation at January 1, 2012.

Table C – 2 reconciles the number of participants in the last valuation to the number of participants in the current valuation.

PARTICIPANT DATA

Table C.1—Participant Data

Membership data as at December 31, 2014 was received from the Corporation via e-mail and included information such as name, sex, age, date of hire, current salary, benefit amounts and other applicable details for all active employees and people in receipt of benefits.

Included in the participant data for the Corporation is the percentage to be used to prorate the liability for each individual between the Water and Electric divisions.

We have reviewed the data and compared it to the data used in the prior valuation for consistency and reliability for use in this valuation. The main tests of sufficiency and reliability that were conducted on the membership data are as follows:

- Date of hire prior to date of birth
- Salaries less than $20,000 per year, or greater than $250,000 per year
- Ages under 18 or over 100
- Abnormal levels of benefits and/or premiums
- Duplicate records

In addition, the following tests were performed:

- A reconciliation of statuses from the prior valuation to the current valuation;
- A review of the consistency of individual data items and statistical summaries between the current and prior valuations; and
- A review of the reasonableness of changes in such information since the prior valuation.

Active Employees

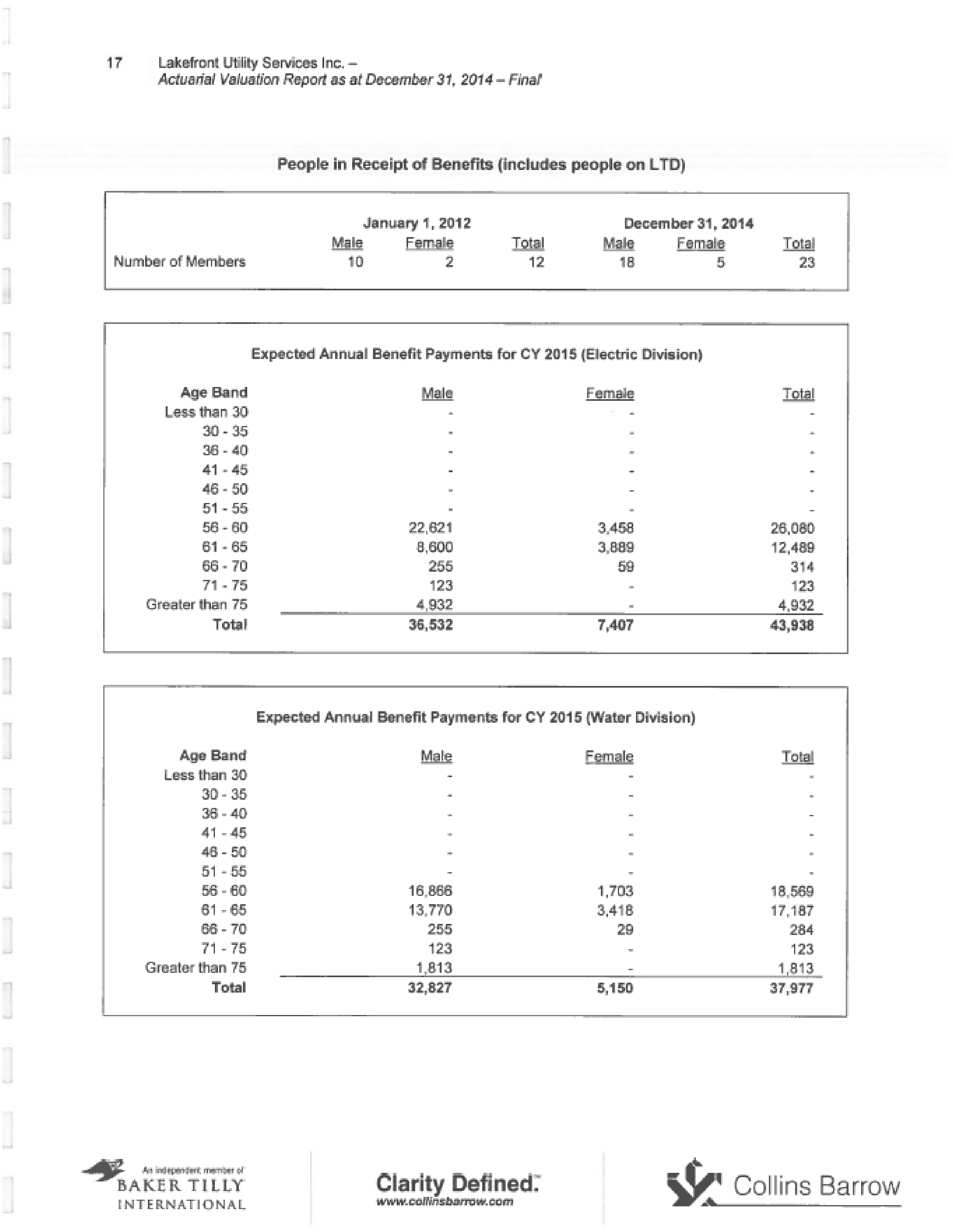
	January 1, 2012			December 31, 2014		
	Male	Female	Total	Male	Female	Total
Number of Employees	25	11	36	19	8	27
Avg. Length of Service	12.3	12.1	12.2	7.2	11.6	8.5

Count as of December 31, 2014

	Active Lives - Not Fully Eligible			Active Lives - Fully Eligible		
Age Band	Male	Female	Total	Male	Female	Total
Less than 30	3	-	3	-	-	-
30 - 35	5	-	5	-	-	-
36 - 40	1	3	4	-	-	-
41 - 45	2	1	3	-	-	-
46 - 50	5	2	7	-	-	-
51 - 55	2	1	3	-	-	-
56 - 60	-	1	1	-	-	-
61 - 65	1	-	1	-	-	-
66 - 70	-	-	-	-	-	-
71 - 75	-	-	-	-	-	-
Greater than 75	-	-	-	-	-	-
Total	**19**	**8**	**27**	-	-	-

Average Service as of December 31, 2014

	Active Lives - Not Fully Eligible			Active Lives - Fully Eligible		
Age Band	Male	Female	Total	Male	Female	Total
Less than 30	2.8	-	2.8	-	-	-
30 - 35	4.3	-	4.3	-	-	-
36 - 40	6.6	3.9	4.5	-	-	-
41 - 45	7.0	4.2	6.0	-	-	-
46 - 50	9.2	20.4	12.4	-	-	-
51 - 55	6.8	35.5	16.4	-	-	-
56 - 60	-	0.7	0.7	-	-	-
61 - 65	25.6	-	25.6	-	-	-
66 - 70	-	-	-	-	-	-
71 - 75	-	-	-	-	-	-
Greater than 75	-	-	-	-	-	-
Total	**7.2**	**11.6**	**8.5**	-	-	-



People in Receipt of Benefits (includes people on LTD)

	January 1, 2012			December 31, 2014		
	Male	Female	Total	Male	Female	Total
Number of Members	10	2	12	18	5	23

Expected Annual Benefit Payments for CY 2015 (Electric Division)

Age Band	Male	Female	Total
Less than 30	-	-	-
30 - 35	-	-	-
36 - 40	-	-	-
41 - 45	-	-	-
46 - 50	-	-	-
51 - 55	-	-	-
56 - 60	22,621	3,458	26,080
61 - 65	8,600	3,889	12,489
66 - 70	255	59	314
71 - 75	123	-	123
Greater than 75	4,932	-	4,932
Total	**36,532**	**7,407**	**43,938**

Expected Annual Benefit Payments for CY 2015 (Water Division)

Age Band	Male	Female	Total
Less than 30	-	-	-
30 - 35	-	-	-
36 - 40	-	-	-
41 - 45	-	-	-
46 - 50	-	-	-
51 - 55	-	-	-
56 - 60	16,866	1,703	18,569
61 - 65	13,770	3,418	17,187
66 - 70	255	29	284
71 - 75	123	-	123
Greater than 75	1,813	-	1,813
Total	**32,827**	**5,150**	**37,977**

PARTICIPATION RECONCILIATION

Table C.2—Participation Reconciliation

Participant Reconciliation

	Actives	Retired
As at Jan. 1, 2012	**36**	**12**
New Entrants	7 [1]	-
New Dependants	-	-
Active	-	-
LTD	-	-
Terminated	(4)	-
Deceased	-	(1)
Retired	(12)	12
No Longer Eligible	-	-
As at Dec. 31, 2014	**27**	**23**

[1] *One of the individuals was hired in 2011 and was not included in the previous valuation database.*

SECTION D— SUMMARY OF ACTUARIAL METHOD AND ASSUMPTIONS

ACTUARIAL METHOD

The aim of an actuarial valuation of post-retirement non-pension benefits is to provide a reasonable and systematic allocation of the cost of these future benefits to the years in which the related employees' services are rendered. To accomplish this, it is necessary to:

- make assumptions for discount rates, salary rate increases, mortality and other decrements;
- use these assumptions to calculate the present value of the expected future benefits; and
- adopt an actuarial cost method to allocate the present value of expected future benefits to the specific years of employment.

The Present Value of the Defined Benefit Obligation and Current Service Cost were determined using the projected benefit method, pro-rated on service. This is the method stipulated by PS 3250 and IAS 19 when future salary levels or cost escalation affect the amount of the employee's future benefits. Under this method, the projected post-retirement benefits are deemed to be earned on a pro-rata basis over the years of service in the attribution period. IAS 19 stipulates that the attribution period commences on the date when service by the employee first leads to post-retirement non-pension benefits under the plan and ends on the date when further service by the employee will lead to no material amount of further post-retirement non-pension benefits under the plan, other than from further salary increases. PS 3250 stipulates that the attribution period commences at the employee's hire date and ends at the date of retirement.

For each employee not yet fully eligible for benefits, the Present Value of the Defined Benefit Obligation is equal to the present value of expected future benefits multiplied by the ratio of the years of service to the valuation date to the total years of service in the attribution period. The Current Service Cost is equal to the present value of expected future benefits multiplied by the ratio of the year (or part) of service in the fiscal year to total years of service in the attribution period.

For health and dental benefits, the Corporation has selected the premium rates charged to retirees as management's best estimate of the benefits costs to be incurred. The total monthly premium rates used for the period Jan. 1, 2015 to Dec. 31, 2015, inclusive of premium taxes, are as follows:

	Health Premiums		Dental Premiums	
Retiree Division	**Single Coverage**	**Family Coverage**	**Single Coverage**	**Family Coverage**
Management	$ 113.32	$ 265.11	$ 87.84	$ 211.33
Union	$ 109.64	$ 254.61	$ 68.40	$ 164.51

The above premium rates were provided by the Corporation and represent the rates at 100%, prior to any cost-sharing provisions.

The PV DBO at December 31, 2014 is based on membership data and management's best estimate assumptions at December 31, 2014.

The calculation of the PV DBO for each of the Electric and Water divisions is based on the sum of the PV DBO calculated for each employee prorated based on their percentage factor for the Corporation.

MANAGEMENT'S BEST ESTIMATE ASSUMPTIONS

The following are management's best estimate economic and demographic assumptions as at December 31, 2014.

ECONOMIC ASSUMPTIONS

Consumer Price Index

The consumer price index is assumed to be 2.00% per annum.

This assumption remains unchanged from the previous valuation.

Discount Rate

The rate used to discount future benefits is assumed to be 3.90% per annum as at December 31, 2014. This rate reflects the market interest rates at the measurement date on high quality debt instruments with consideration given to the timing and amount of projected benefit payments.

The assumption used in the previous valuation was 4.00% per annum as at December 31, 2012.

Salary Increase Rate

The rate used to increase salaries is assumed to be 3.00% per annum. This rate reflects the expected Consumer Price Index adjusted for productivity, merit and promotion adjusted for company-specific information.

The assumption used in the previous valuation was 3.30% per annum.

Claims Cost Trend Rate

The rates used to project benefits costs into the future are assumed to be as follows:

	Current Valuation		Previous Valuation	
End of Year	Health	Dental	Health	Dental
2015	6.50%	4.50%	6.40%	4.80%
2016	6.25%	4.50%	5.87%	4.80%
2017	6.00%	4.50%	5.33%	4.80%
2018	5.75%	4.50%	4.80%	4.80%
2019	5.50%	4.50%	4.80%	4.80%
2020	5.25%	4.50%	4.80%	4.80%
2021	5.00%	4.50%	4.80%	4.80%
2022	4.75%	4.50%	4.80%	4.80%
2023 and Thereafter	4.50%	4.50%	4.80%	4.80%

DEMOGRAPHIC ASSUMPTIONS

Mortality Table

The mortality tables used are as per the Canadian Institute of Actuaries Canadian Pensioners' Mortality Pension Experience Subcommittee final report dated February 11, 2014 (CIA Report). More specifically, the Canada Pensioners Mortality ("CPM") Table Public Sector (CPM2014 PUBL) has been used with the generational projection of mortality improvement based upon CPM Improvement Scale B1-2014.

Mortality rates are applied on a sex-distinct basis.

The prior valuation assumption was the 1994 Uninsured Pensioner Mortality (UP-94) table, with a generational projection of mortality improvements based upon Projection Scale AA.

Rates of Withdrawal

Termination of employment is assumed to be in accordance with the following withdrawal table, which was compiled using withdrawal experience for a group of local distribution companies and municipalities for which data was available:

Age Bucket	Withdrawal Rate per Annum
18 – 29	2.75%
30 – 34	2.25%
35 – 39	2.00%
40 – 54	1.50%

This assumption remains unchanged from the previous valuation.

Retirement Age

All active employees are assumed to retire at age 60 (or immediately if currently over age 60), which was based on the Corporation's retirement experience as well as a seven year retirement experience study on a group of local distribution companies for which data was available. The assumed retirement age of 60 was increased, if necessary, to the minimum of the age at which requirements to retire under an unreduced pension from the Ontario Municipal Employees Retirement System (OMERS) were met and age 65.

This assumption remains unchanged from the previous valuation.

Disability

No provision was made for future disability. It is assumed that individuals currently receiving long-term disability benefits will remain disabled until retirement at age 65.

This assumption remains unchanged from the previous valuation.

Family/Single Coverage

It is assumed that the coverage type as at December 31, 2014, as provided by the Corporation, will remain the same until the employee reaches the assumed retirement age. For family coverage, it is assumed that the retiree has a spouse of opposite gender and no other dependents.

These assumptions remain unchanged from the previous valuation.

Additionally, male spouses are assumed to be three years older than female spouses.

Expenses and Taxes

We have assumed 10% of benefits is required for the cost of sponsoring the program for life insurance. We have assumed taxes and expenses are included in the premium rates for health and dental benefits.

These assumptions remain unchanged from the previous valuation.

SECTION E— SUMMARY OF POST-RETIREMENT BENEFITS

The following is a summary of the plan provisions that are pertinent to this valuation, based on information provided by and discussions with the Corporation.

GOVERNING DOCUMENTS

The program is governed by the following documents:

- Collective Agreement between Lakefront Utility Services Inc. and Local 25 Canadian Union of Public Employees (Outside and Office Employees), February 1, 2014 to January 31, 2017
- Sun Life Financial Group Benefits Booklet for Lakefront Utility Services Inc. Active Non-Union employees, effective June 1, 2015
- Sun Life Financial Group Benefits Booklet for Lakefront Utility Services Inc. Non-Union employees retiring before age 65 on an unreduced pension from Ontario Municipal Retirement System, effective June 1, 2015
- Sun Life Financial Group Benefits Booklet for Lakefront Utility Services Inc. Union employees retiring before age 65 on an unreduced pension from the Ontario Municipal Employees Retirement System, effective June 1, 2015

What follows is only a summary of the post retirement non-pension benefits program. For a complete description, please refer to the above-noted documents.

ELIGIBILITY

Upon retirement, all employees of the Corporation are eligible for post-retirement life insurance.

All employees who retire on an unreduced early pension from the Ontario Municipal Employees Retirement System (OMERS), between the ages of fifty-five (55) and sixty-five (65) years are eligible for post-retirement health and dental benefits.

PARTICIPANT CONTRIBUTIONS

The Corporation shall pay 100% of the cost of the life insurance.

Effective February 1, 2010, the Corporation shall pay 100% of the cost of the health and dental benefits to all retiring eligible employees. There are no retirees who retired prior to February 1, 2010 currently receiving health or dental benefits.

PAST SERVICE

Past service is defined as continuous service prior to joining the plan if the participant was employed by another electrical distribution company/hydro prior to joining the Corporation.

LENGTH OF SERVICE

Length of service is defined as continuous service from the date of hire to the valuation date, measured in years and months.

SUMMARY OF BENEFITS

Life Insurance

Eligible employees are entitled to the following post-retirement life insurance, as per the MEARIE plan, administered by Great West Life, based upon the following table:

Plan Option	Amount of Coverage	Eligibility
1	Flat $2,000.	If employee retires with less than 10 years of service in the Plan.
2	50% of final annual earnings reducing by 2.5% of final annual earnings each year thereafter for 10 years, to a final benefit equal to 25.0% of final annual earnings. Reduction occurs on anniversary date of retirement.	If employee was ever insured under Employee Plan options 2, 3 or 4, or if employee retires with 10 or more years of service in Plan but was never in superseded plan.
3	50% of final annual earnings.	If employee was insured under superseded plan and was hired on or after May 1, 1967 and elected coverage under Option 1 only.
4	70% of the final amount insured for under the life plan immediately prior to retirement.	If employee was insured under the superseded plan and was hired before May 1, 1967 and elected coverage under Option 1 only.

Health, Dental, and Vision Benefits

All eligible employees are entitled to receive post-retirement health and dental benefits until age 65.

A detailed description of the health and dental benefits covered under the post-retirement non-pension benefits plan can be found in the above-noted agreements.

SECTION F—
EMPLOYER CERTIFICATION

Post-Retirement Non-Pension Benefit Plan
of Lakefront Utility Services Inc.
Actuarial Valuation as at December 31, 2014

I hereby confirm as an authorized signing officer of the administrator of the Post-Retirement Non-Pension Benefit Plan of Lakefront Utility Services Inc. that, to the best of my knowledge and belief, for the purposes of the valuation:

i) the membership data summarized in Section C is accurate and complete;

ii) the assumptions upon which this report is based as summarized in Section D, are management's best estimate assumptions and are adequate and appropriate for the purposes of this valuation; and

iii) the summary of Plan Provisions in Section E is an accurate and complete summary of the terms of the Plan in effect on December 31, 2014.

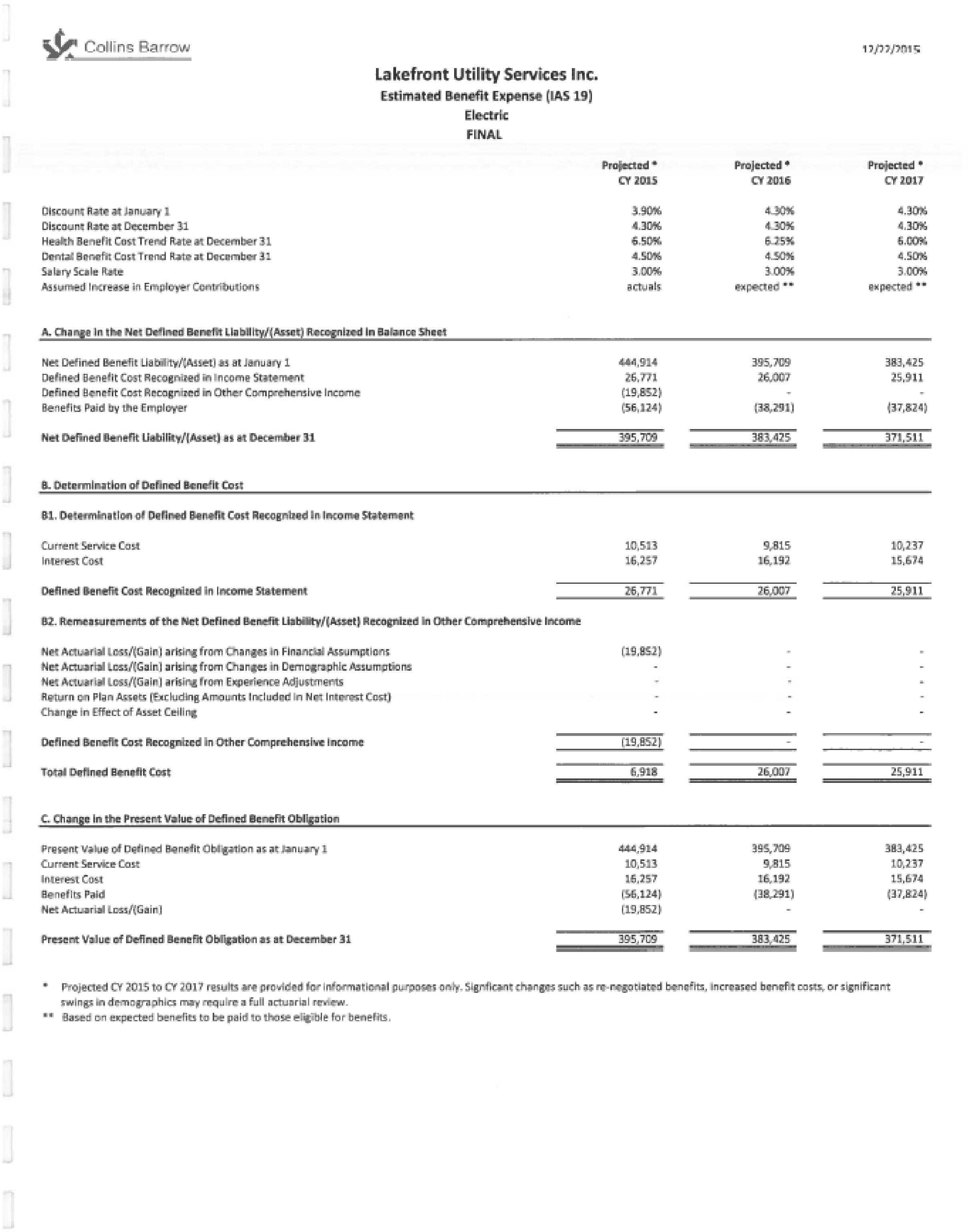
LAKEFRONT UTILITY SERVICES INC.

Dec/21/2015
Date

Signature

Derek Bird
Name

President
Title



Collins Barrow

12/22/2015

Lakefront Utility Services Inc.

Estimated Benefit Expense (IAS 19)

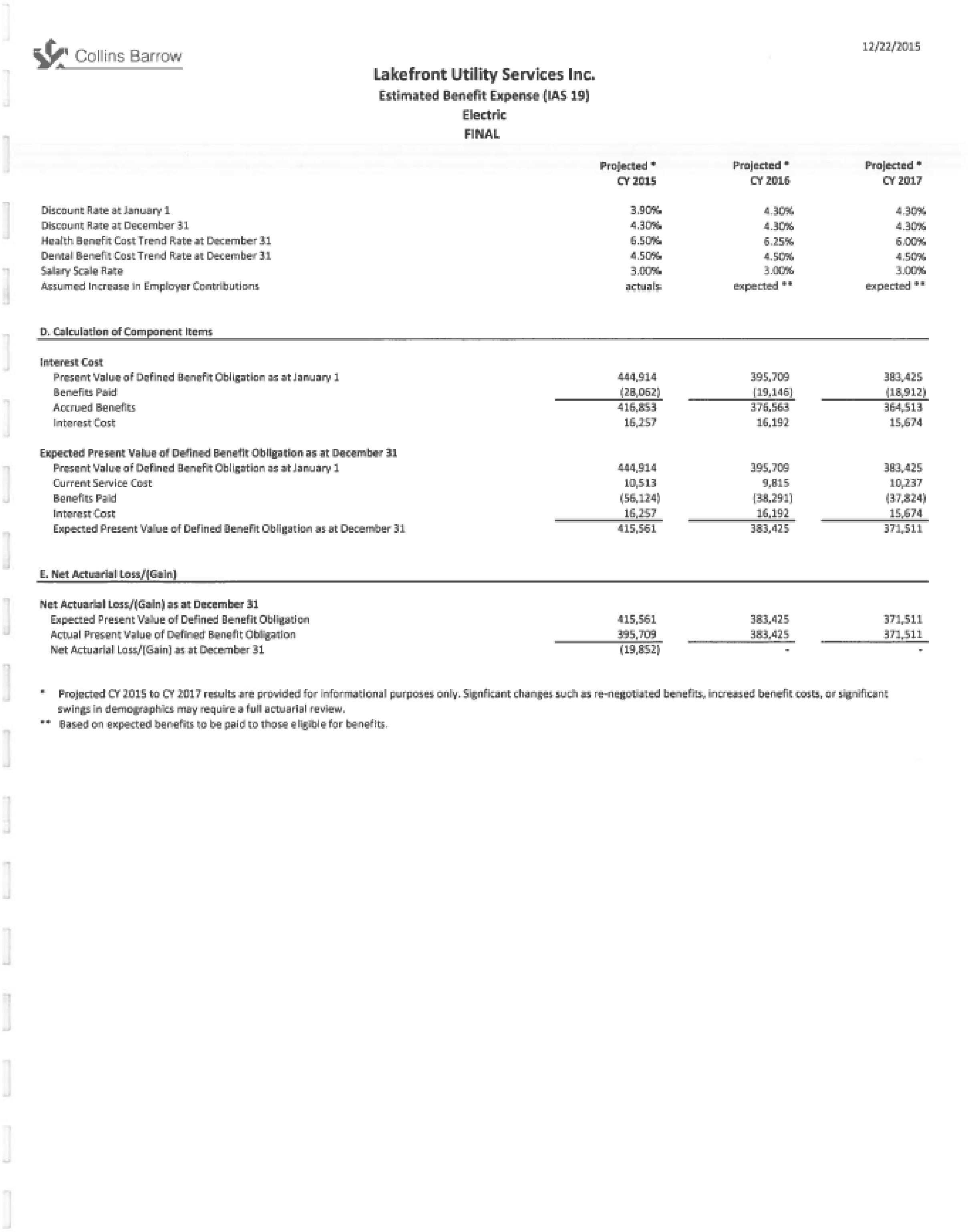
Electric

FINAL

	Projected * CY 2015	Projected * CY 2016	Projected * CY 2017
Discount Rate at January 1	3.90%	4.30%	4.30%
Discount Rate at December 31	4.30%	4.30%	4.30%
Health Benefit Cost Trend Rate at December 31	6.50%	6.25%	6.00%
Dental Benefit Cost Trend Rate at December 31	4.50%	4.50%	4.50%
Salary Scale Rate	3.00%	3.00%	3.00%
Assumed Increase in Employer Contributions	actuals	expected **	expected **
A. Change in the Net Defined Benefit Liability/(Asset) Recognized in Balance Sheet			
Net Defined Benefit Liability/(Asset) as at January 1	444,914	395,709	383,425
Defined Benefit Cost Recognized in Income Statement	26,771	26,007	25,911
Defined Benefit Cost Recognized in Other Comprehensive Income	(19,852)	-	-
Benefits Paid by the Employer	(56,124)	(38,291)	(37,824)
Net Defined Benefit Liability/(Asset) as at December 31	395,709	383,425	371,511
B. Determination of Defined Benefit Cost			
B1. Determination of Defined Benefit Cost Recognized in Income Statement			
Current Service Cost	10,513	9,815	10,237
Interest Cost	16,257	16,192	15,674
Defined Benefit Cost Recognized in Income Statement	26,771	26,007	25,911
B2. Remeasurements of the Net Defined Benefit Liability/(Asset) Recognized in Other Comprehensive Income			
Net Actuarial Loss/(Gain) arising from Changes in Financial Assumptions	(19,852)	-	-
Net Actuarial Loss/(Gain) arising from Changes in Demographic Assumptions	-	-	-
Net Actuarial Loss/(Gain) arising from Experience Adjustments	-	-	-
Return on Plan Assets (Excluding Amounts Included in Net Interest Cost)	-	-	-
Change in Effect of Asset Ceiling	-	-	-
Defined Benefit Cost Recognized in Other Comprehensive Income	(19,852)	-	-
Total Defined Benefit Cost	6,918	26,007	25,911
C. Change in the Present Value of Defined Benefit Obligation			
Present Value of Defined Benefit Obligation as at January 1	444,914	395,709	383,425
Current Service Cost	10,513	9,815	10,237
Interest Cost	16,257	16,192	15,674
Benefits Paid	(56,124)	(38,291)	(37,824)
Net Actuarial Loss/(Gain)	(19,852)	-	-
Present Value of Defined Benefit Obligation as at December 31	395,709	383,425	371,511

* Projected CY 2015 to CY 2017 results are provided for informational purposes only. Signficant changes such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require a full actuarial review.

** Based on expected benefits to be paid to those eligible for benefits.



Collins Barrow

12/22/2015

Lakefront Utility Services Inc.

Estimated Benefit Expense (IAS 19)

Electric

FINAL

	Projected * CY 2015	Projected * CY 2016	Projected * CY 2017
Discount Rate at January 1	3.90%	4.30%	4.30%
Discount Rate at December 31	4.30%	4.30%	4.30%
Health Benefit Cost Trend Rate at December 31	6.50%	6.25%	6.00%
Dental Benefit Cost Trend Rate at December 31	4.50%	4.50%	4.50%
Salary Scale Rate	3.00%	3.00%	3.00%
Assumed Increase in Employer Contributions	actuals	expected **	expected **

D. Calculation of Component Items

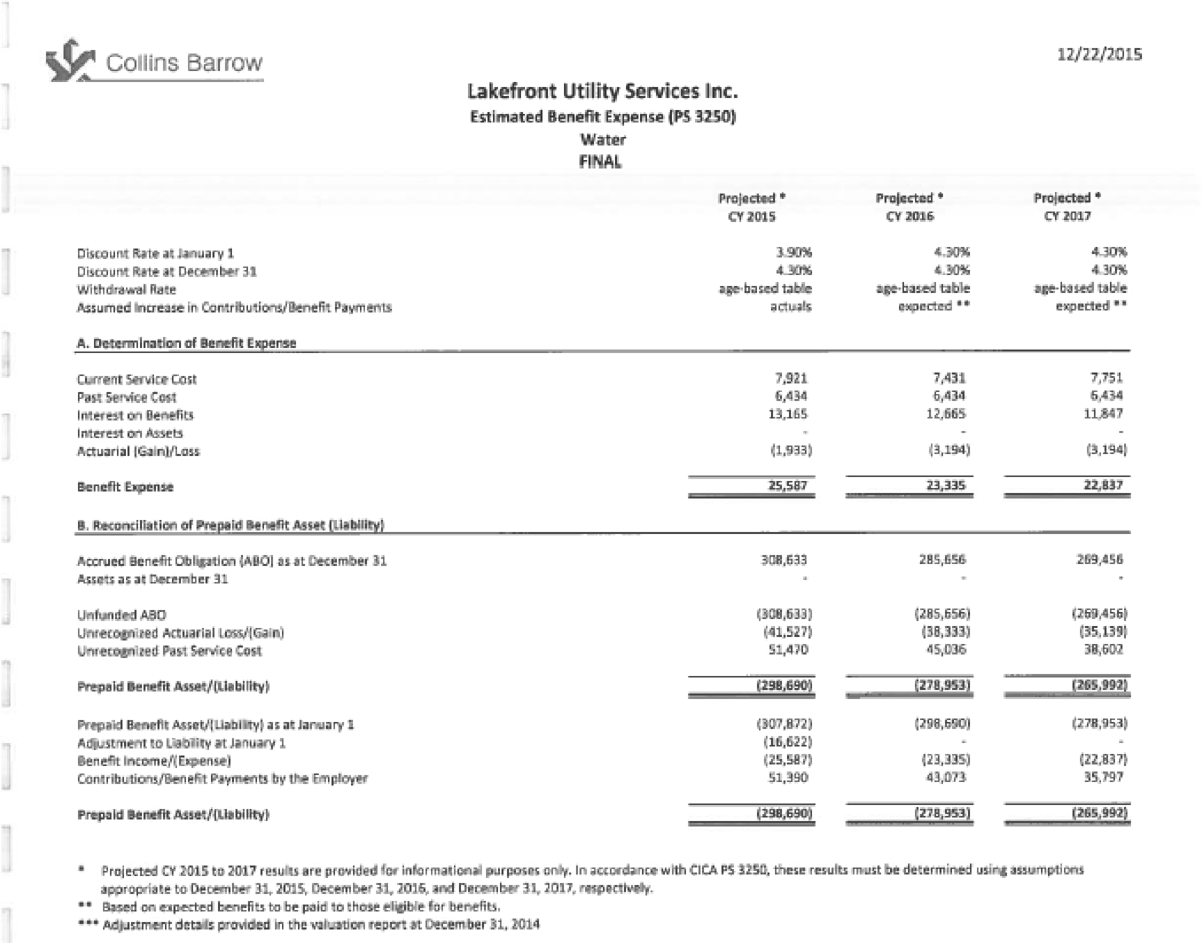
	Projected * CY 2015	Projected * CY 2016	Projected * CY 2017
Interest Cost			
Present Value of Defined Benefit Obligation as at January 1	444,914	395,709	383,425
Benefits Paid	(28,062)	(19,146)	(18,912)
Accrued Benefits	416,853	376,563	364,513
Interest Cost	16,257	16,192	15,674
Expected Present Value of Defined Benefit Obligation as at December 31			
Present Value of Defined Benefit Obligation as at January 1	444,914	395,709	383,425
Current Service Cost	10,513	9,815	10,237
Benefits Paid	(56,124)	(38,291)	(37,824)
Interest Cost	16,257	16,192	15,674
Expected Present Value of Defined Benefit Obligation as at December 31	415,561	383,425	371,511

E. Net Actuarial Loss/(Gain)

	Projected * CY 2015	Projected * CY 2016	Projected * CY 2017
Net Actuarial Loss/(Gain) as at December 31			
Expected Present Value of Defined Benefit Obligation	415,561	383,425	371,511
Actual Present Value of Defined Benefit Obligation	395,709	383,425	371,511
Net Actuarial Loss/(Gain) as at December 31	(19,852)	-	-

* Projected CY 2015 to CY 2017 results are provided for informational purposes only. Signficant changes such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require a full actuarial review.

** Based on expected benefits to be paid to those eligible for benefits.



Collins Barrow

12/22/2015

Lakefront Utility Services Inc.

Estimated Benefit Expense (PS 3250)

Water

FINAL

	Projected * CY 2015	Projected * CY 2016	Projected * CY 2017
Discount Rate at January 1	3.90%	4.30%	4.30%
Discount Rate at December 31	4.30%	4.30%	4.30%
Withdrawal Rate	age-based table	age-based table	age-based table
Assumed Increase in Contributions/Benefit Payments	actuals	expected **	expected **
A. Determination of Benefit Expense			
Current Service Cost	7,921	7,431	7,751
Past Service Cost	6,434	6,434	6,434
Interest on Benefits	13,165	12,665	11,847
Interest on Assets	-	-	-
Actuarial (Gain)/Loss	(1,933)	(3,194)	(3,194)
Benefit Expense	**25,587**	**23,335**	**22,837**
B. Reconciliation of Prepaid Benefit Asset (Liability)			
Accrued Benefit Obligation (ABO) as at December 31	308,633	285,656	269,456
Assets as at December 31	-	-	-
Unfunded ABO	(308,633)	(285,656)	(269,456)
Unrecognized Actuarial Loss/(Gain)	(41,527)	(38,333)	(35,139)
Unrecognized Past Service Cost	51,470	45,036	38,602
Prepaid Benefit Asset/(Liability)	**(298,690)**	**(278,953)**	**(265,992)**
Prepaid Benefit Asset/(Liability) as at January 1	(307,872)	(298,690)	(278,953)
Adjustment to Liability at January 1	(16,622)	-	-
Benefit Income/(Expense)	(25,587)	(23,335)	(22,837)
Contributions/Benefit Payments by the Employer	51,390	43,073	35,797
Prepaid Benefit Asset/(Liability)	**(298,690)**	**(278,953)**	**(265,992)**

* Projected CY 2015 to 2017 results are provided for informational purposes only. In accordance with CICA PS 3250, these results must be determined using assumptions appropriate to December 31, 2015, December 31, 2016, and December 31, 2017, respectively.

** Based on expected benefits to be paid to those eligible for benefits.

*** Adjustment details provided in the valuation report at December 31, 2014

Collins Barrow

12/22/2015

Lakefront Utility Services Inc.

Estimated Benefit Expense (PS 3250)

Water

FINAL

	Projected * CY 2015	Projected * CY 2016	Projected * CY 2017
Discount Rate at January 1	3.90%	4.30%	4.30%
Discount Rate at December 31	4.30%	4.30%	4.30%
Withdrawal Rate	age-based table	age-based table	age-based table
Assumed Increase in Contributions/Benefit Payments	actuals	expected **	expected **
C. Calculation of Component Items			
Current Service Cost	7,921	7,431	7,751
Interest on Benefits			
ABO at January 1	355,336	308,633	285,656
Current Service Cost	7,921	7,431	7,751
Benefit Payments	(25,695)	(21,536)	(17,899)
Accrued Benefits	337,562	294,528	275,508
Interest on Benefits	13,165	12,665	11,847
Expected ABO as at December 31			
ABO at January 1	355,336	308,633	285,656
Current Service Cost	7,921	7,431	7,751
Benefit Payments	(51,390)	(43,073)	(35,797)
Interest on Benefits	13,165	12,665	11,847
Expected ABO at December 31	325,032	285,656	269,456
Interest on Assets			
Assets at January 1	-	-	-
Funding	25,695	21,536	17,899
Benefit Payments	(25,695)	(21,536)	(17,899)
Expected Assets	-	-	-
Interest on Assets	-	-	-
Expected Assets as at December 31			
Assets at January 1	-	-	-
Funding	51,390	43,073	35,797
Benefit Payments	(51,390)	(43,073)	(35,797)
Interest on Assets	-	-	-
Expected Assets at December 31	-	-	-

* Projected CY 2015 to 2017 results are provided for informational purposes only. In accordance with CICA PS 3250, these results must be determined using assumptions appropriate to December 31, 2015, December 31, 2016, and December 31, 2017, respectively.

** Based on expected benefits to be paid to those eligible for benefits.

*** Adjustment details provided in the valuation report at December 31, 2014

Collins Barrow

12/22/2015

Lakefront Utility Services Inc.

Estimated Benefit Expense (PS 3250)

Water

FINAL

	Projected * CY 2015	Projected * CY 2016	Projected * CY 2017
Discount Rate at January 1	3.90%	4.30%	4.30%
Discount Rate at December 31	4.30%	4.30%	4.30%
Withdrawal Rate	age-based table	age-based table	age-based table
Assumed Increase in Contributions/Benefit Payments	actuals	expected **	expected **
D. Amortization of Actuarial Loss/(Gain)			
(Gain)/Loss on ABO as at January 1			
Prepaid Benefit Liability/(Asset) as at January 1	307,872	298,690	278,953
Unamortized (Gain)/Loss	(24,079)	(41,527)	(38,333)
Unamortized Past Service Cost	57,904	51,470	45,036
Expected ABO	341,697	308,633	285,656
Adjustment to Liability at January 1	16,622	-	-
Actual ABO	355,336	308,633	285,656
(Gain)/Loss on ABO at January 1	(2,982)	-	-
(Gain)/Loss on Assets as at January 1			
Expected Assets	-	-	-
Actual Assets	-	-	-
(Gain)/Loss on Assets as at January 1	-	-	-
Total (Gain)/Loss as at January 1	(27,061)	(41,527)	(38,333)
Expected Average Remaining Service Life (Years)	14	13	12
Amortization for Current Year	(1,933)	(3,194)	(3,194)
(Gain)/Loss on ABO at December 31			
Expected ABO	325,032	285,656	269,456
Actual ABO	308,633	285,656	269,456
(Gain)/Loss on ABO at December 31	(16,399)	-	-
Unamortized (Gain)/Loss at December 31	(41,527)	(38,333)	(35,139)
E. Amortization of Past Service Cost			
Total Past Service Cost at January 1	57,904	51,470	45,036
Years of Remaining Amortization	9	8	7
Amortization for Current Year	6,434	6,434	6,434
Unamortized Past Service Cost at December 31	51,470	45,036	38,602

* Projected CY 2015 to 2017 results are provided for informational purposes only. In accordance with CICA PS 3250, these results must be determined using assumptions appropriate to December 31, 2015, December 31, 2016, and December 31, 2017, respectively.

** Based on expected benefits to be paid to those eligible for benefits.

*** Adjustment details provided in the valuation report at December 31, 2014

Attachment C - 2015 Tax Return

Canada Revenue Agency Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200
Code 1501

Protected B
when completed

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act* and *Income Tax Regulations*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

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 we were notified? **010** 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 011 to 018)
011 207 Division Street
012
City / Province, territory, or state
015 Cobourg **016** ON
Country (other than Canada) / Postal code/Zip code
017 **018** K9A 4L3

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? **020** 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 021 to 028)
021 c/o
022 207 Division Street
023
City / Province, territory, or state
025 Cobourg **026** ON
Country (other than Canada) / Postal code/Zip code
027 **028** K9A 4L3

Location of books and records (if different from head office address)
Has the location of books and records changed since the last time we were notified? **030** 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 031 to 038)
031 207 Division Street
032
City / Province, territory, or state
035 Cobourg **036** ON
Country (other than Canada) / Postal code/Zip code
037 **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** 2015/01/01
Tax year-end **061** 2015/12/31

Has there been an acquisition of control to which subsection 249(4) applies since the tax year start on line 060? **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 according to subsection 249(3.1)? **066** 1 Yes ☐ 2 No ☒

Is the corporation a professional corporation that is a member of a partnership? **067** 1 Yes ☐ 2 No ☒

Is this the first year of filing after:
Incorporation? **070** 1 Yes ☐ 2 No ☒
Amalgamation? **071** 1 Yes ☐ 2 No ☒
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? **072** 1 Yes ☐ 2 No ☒
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? **076** 1 Yes ☐ 2 No ☒

Is this the final return up to dissolution? **078** 1 Yes ☐ 2 No ☒

If an election was made under section 261, state the functional currency used **079**

Is the corporation a resident of Canada? **080** 1 Yes ☒ 2 No ☐
If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? **082** 1 Yes ☐ 2 No ☒
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085 1 ☐ Exempt under paragraph 149(1)(e) or (l)
2 ☐ Exempt under paragraph 149(1)(j)
3 ☐ Exempt under paragraph 149(1)(t)
4 ☐ Exempt under other paragraphs of section 149

Do not use this area

095	**096**	**898**

T2 E (15) Version 2015.4.3 GP61 - **RETAIN ON FILE. DO NOT SUBMIT TO THE CRA.**

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.

Schedules - Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	☒	9
Is the corporation an associated CCPC?	160	☒	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161	☐	49
Does the corporation have any non-resident shareholders who own voting shares?	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?	166	☐	T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167	☐	T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168	☐	22
Did the corporation own any shares in one or more foreign affiliates in the tax 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
Did the corporation have a total amount over $1 million of reportable transactions with non-arm's length non-residents?	171	☐	T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	☒	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172	☐	----
Does the corporation earn income from one or more Internet webpages or websites?	180	☐	88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	☒	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	☐	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	☒	3
Is the corporation claiming any type of losses?	204	☐	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	☐	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	☐	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207	☐	7
Does the corporation have any property that is eligible for capital cost allowance?	208	☒	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 (other than transitional reserves under section 34.2)?	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	☒	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	☒	----
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 in the tax year?	**271**	☐	T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$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 ☒

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**	289,258	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")				289,258	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			**355**		D
Taxable income (amount C **plus** amount D)			**360**	289,258	
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 3.5 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**	289,258	A
Taxable income from line 360 on page 3, **minus** 100/28 of the amount on line 632* on page 7, **minus** 4 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**	289,258	B
Business limit (see notes 1 and 2 below)	**410**	500,000	C

Notes: 1. For CCPCs that are not associated, enter $500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 X **415** *** 24,485 D / 11,250 = 1,088,222 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, 2016 (365) / Number of days in the tax year (365) x 17% = 0 1

Amount A, B, C, or F, whichever is the least ______ x Number of days in the tax year after December 31, 2015, and before January 1, 2017 ( ) / Number of days in the tax year (365) x 17.5% = 0 2

Total of amounts 1 and 2 (enter amount G on line I on page 7) **430** 0 G

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation 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 page 3 (line 360 or amount Z, whichever applies)				289,258	A
Lesser of amounts B9 and H9 from Part 9 of Schedule 27			B		
Amount K13 from Part 13 of Schedule 27			C		
Personal service business income	**432**		D		
Amount used to calculate the credit union deduction (amount F from Schedule 17)			E		
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			F		
Aggregate investment income from line 440 on page 6*			G		
Subtotal (**add** amounts B to G)			▶		H
Amount A **minus** amount H (if negative, enter "0")				289,258	I
General tax reduction for Canadian-controlled private corporations – Amount I **multiplied** by 13%				37,604	J

Enter amount J on line 638 of page 7.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, 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)					K
Lesser of amounts B9 and H9 from Part 9 of Schedule 27			L		
Amount K13 from Part 13 of Schedule 27			M		
Personal service business income	**434**		N		
Amount used to calculate the credit union deduction (amount F from Schedule 17)			O		
Subtotal (**add** amounts L to O)			▶		P
Amount K **minus** amount P (if negative, enter "0")					Q
General tax reduction – Amount Q **multiplied** by 13%					R

Enter amount R 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 ______ B

Deduct:
Foreign investment income from Schedule 7 **445** ______ X 9 1/3 % = ______ C
(if negative, enter "0") ______ ▶ ______ D

Amount **A minus** amount D (if negative, enter "0") ______ E

Taxable income from line 360 on page 3 289,258 F

Deduct:
Amount on line 400, 405, 410, or 425 on page 4, whichever is the least ______ G
Foreign non-business income tax credit from line 632 of page 7 ______ x 100/35 = ______ ______ H
Foreign business income tax credit from line 636 of page 7 ______ x 4.00000 = ______ ______ I
Subtotal ______ ▶ ______ J
289,258 K x 26 2/3% = 77,135 L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) 43,388 M

Refundable portion of Part I tax – Amount E, L, or M, whichever is the least **450** 0 N

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** ______
______ ▶ ______ O

Add the total of:
Refundable portion of Part I tax from line 450 above ______ P
Total Part IV tax payable from Schedule 3 ______ Q
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation **480** ______
______ ▶ ______ R

Refundable dividend tax on hand at the end of the tax year - Amount O **plus** amount R **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 3 206,000 X 1/3 68,667 S

Refundable dividend tax on hand at the end of the tax year from line 485 above ______ T

Dividend refund – Amount S or T, whichever is less 0 U

Enter amount U on line 784 on page 8.

Part I tax

Base amount of Part I tax

taxable income from page 3 (line 360 or amount Z, whichever applies) multiplied by 38%	**550**	109,918	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				C
Taxable income from line 360 on page 3	289,258	D		
Deduct: Amount on line 400, 405, 410, or 425 of page 4, whichever is the least		E		
Net amount (amount D **minus** amount E)	289,258	▶	289,258	F

Refundable tax on CCPC's investment income – 6 2/3% of whichever is less: amount C or amount F	**604**		G
Subtotal (**add** amounts A, B, and G)		109,918	H

Deduct:

Small business deduction from line 430 on page 4			I		
Federal tax abatement	**608**	28,926			
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 J on page 5	**638**	37,604			
General tax reduction from amount R on page 5	**639**				
Federal logging tax credit from Schedule 21	**640**				
Eligible Canadian bank deduction under section 125.21	**641**				
Federal qualifying environmental trust tax credit	**648**				
Investment tax credit from Schedule 31	**652**				
Subtotal		66,530	▶	66,530	J
Part I tax payable – Amount H **minus** amount J				43,388	K

Enter amount K on line 700 on page 8.

Privacy statement

Personal information is collected under the *Income Tax Act* to administer tax, benefits, and related programs. It may also be used for any purpose related to the administration or enforcement of the Act such as audit, compliance and the payment of debts owed to the Crown. It may be shared or verified with other federal, provincial/territorial government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the *Privacy Act*, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source **http://www.cra-arc.gc.ca/gncy/tp/nfsrc/nfsrc-eng.html**, personal information bank CRA PPU 047.

Summary of tax and credits

Federal tax

Part I tax payable from amount K on page 7	**700**	43,388
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		43,388

Add provincial or territorial tax:

Provincial or territorial jurisdiction **750** ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec, and Alberta)	**760**	33,265	
Total provincial or territorial tax		33,265 ▶	33,265
Total tax payable	**770**		76,653 A

Deduct other credits:

Investment tax credit refund from Schedule 31	**780**		
Dividend refund from amount U on 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**	277,814	
Total credits	**890**	277,814	277,814 B

Refund Code **894** 2 Overpayment 201,161

Balance (line A **minus** line B) (201,161)

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

For information on how to make your payment, go to **www.cra-arc.gc.ca/payments**.

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 ☐

If this return was prepared by a tax preparer for a fee, provide their EFILE number **920** A3270

Certification

I, **950** Paul (Last name) **951** Dereck (First name) **954** President (Position, office or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

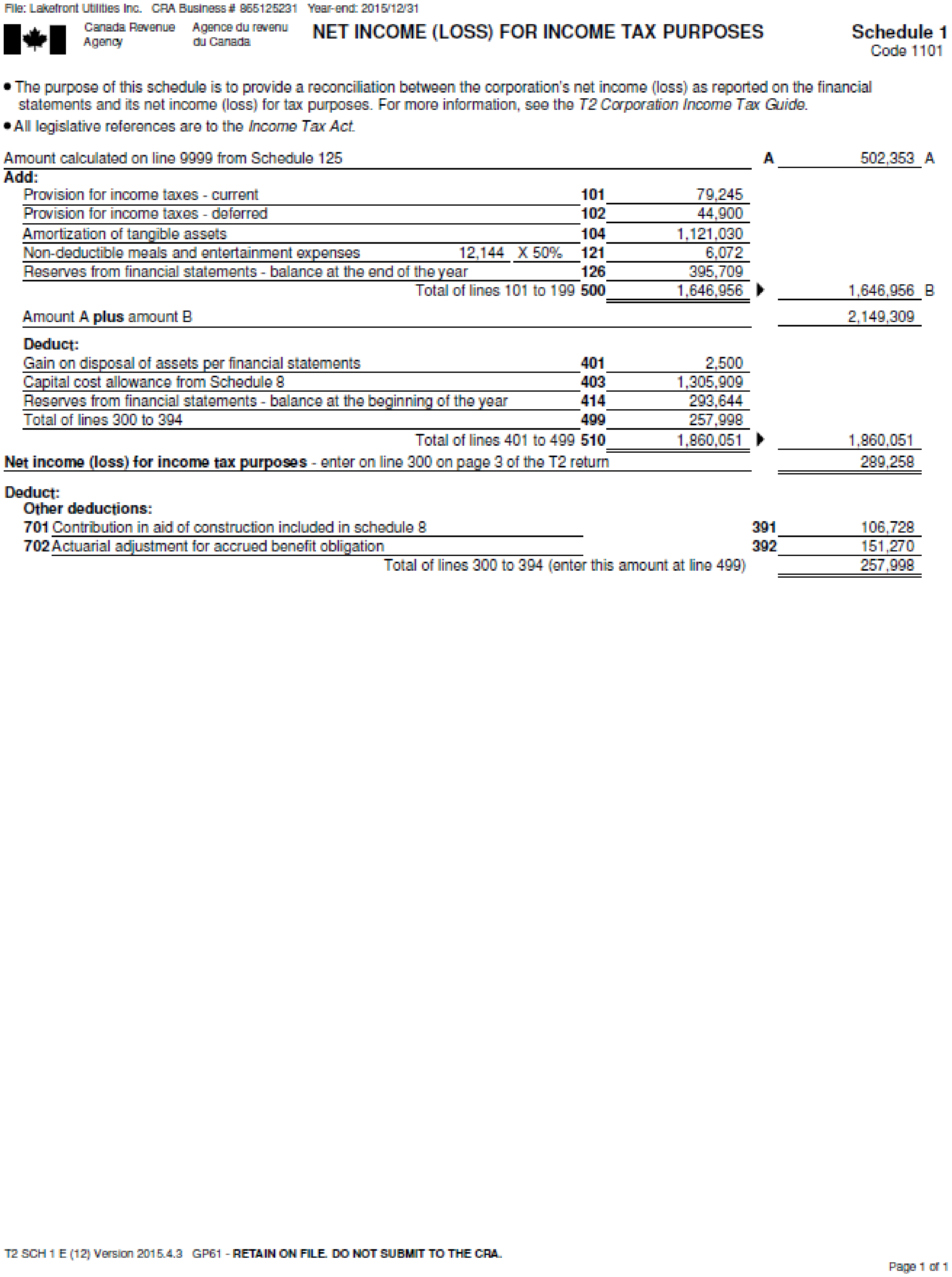
955 2016/04/05 (Date) ______ (Signature of the authorized signing officer of the corporation) **956** (905) 372-2193 (Telephone number)

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.



File: Lakefront Utilities Inc.   CRA Business # 865125231   Year-end: 2015/12/31

Canada Revenue Agency   Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

Schedule 1
Code 1101

- 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*.
- All legislative references are to the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				**A**	502,353 A
Add:					
Provision for income taxes - current		**101**	79,245		
Provision for income taxes - deferred		**102**	44,900		
Amortization of tangible assets		**104**	1,121,030		
Non-deductible meals and entertainment expenses	12,144 X 50%	**121**	6,072		
Reserves from financial statements - balance at the end of the year		**126**	395,709		
Total of lines 101 to 199		**500**	1,646,956	▶	1,646,956 B
Amount A **plus** amount B					2,149,309
Deduct:					
Gain on disposal of assets per financial statements		**401**	2,500		
Capital cost allowance from Schedule 8		**403**	1,305,909		
Reserves from financial statements - balance at the beginning of the year		**414**	293,644		
Total of lines 300 to 394		**499**	257,998		
Total of lines 401 to 499		**510**	1,860,051	▶	1,860,051
Net income (loss) for income tax purposes - enter on line 300 on page 3 of the T2 return					289,258

Deduct:

Other deductions:

701 Contribution in aid of construction included in schedule 8	**391**	106,728
702 Actuarial adjustment for accrued benefit obligation	**392**	151,270
Total of lines 300 to 394 (enter this amount at line 499)		257,998

T2 SCH 1 E (12) Version 2015.4.3   GP61 - **RETAIN ON FILE. DO NOT SUBMIT TO THE CRA.**

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File: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2015/12/31

Canada Revenue Agency | Agence du revenu du Canada

DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

Schedule 3
Code 0401

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act*.
- A recipient corporation is connected with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- If you need more space, continue on a separate schedule.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.

Part 1 - Dividends received in the tax year

Do not include dividends received from foreign non-affiliates.

				Complete if payer corporation is connected		
	A			B	C	D
	Name of payer corporation (from which the corporation received the dividend) 200	Dividends from foreign source?	Dividends subject to Part IV tax?	Enter 1 if payer corporation is connected 205	Business Number of connected corporation 210	Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid 220
					RC	

Note: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each taxation year of the payer corporation.

			Complete if payer corporation is connected				
	E	F	G	H	I	GRIP / LRIP	
	Non-taxable dividend under section 83 230	Taxable dividends deductible from tax income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)* 240	Total taxable dividends paid by connected payer corporation (for tax year in column D) 250	Dividend refund of the connected payer corporation (for tax year in column D)** 260	Part IV tax before deductions F x 1/3*** 270	Column F deduction type	Indicate eligible dividends
			0	0	0		

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

*** For dividends received from connected corporations

$$\text{Part IV tax} = \frac{\text{Column F x Column H}}{\text{Column G}}$$

1

2

Part 2 - Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1)				
Deduct:				
Part IV.I tax payable on dividends subject to Part IV tax			320	
		Subtotal		
Deduct:				
Current-year non-capital loss claimed to reduce Part IV tax	330			
Non-capital losses from previous years claimed to reduce Part IV tax	335			
Current-year farm loss claimed to reduce Part IV tax	340			
Farm losses from previous years claimed to reduce Part IV tax	345			
Total losses applied against Part IV tax		x 1/3 =		
Part IV tax payable (enter amount on line 712 of the T2 return)			360	0

Part 3 - Taxable dividends paid in the tax year for purposes of a dividend refund

	A	B	C	D
	Name of connected recipient corporation 400	Business number 410	Tax year end of connected recipient corporation in which the dividends in column D were received 420	Taxable dividends paid to connected corporations 430
1	Town of Cobourg Holdings Inc.	86511 7832 RC 0001	2015/12/31	206,000
		RC		
			Total	206,000

Note

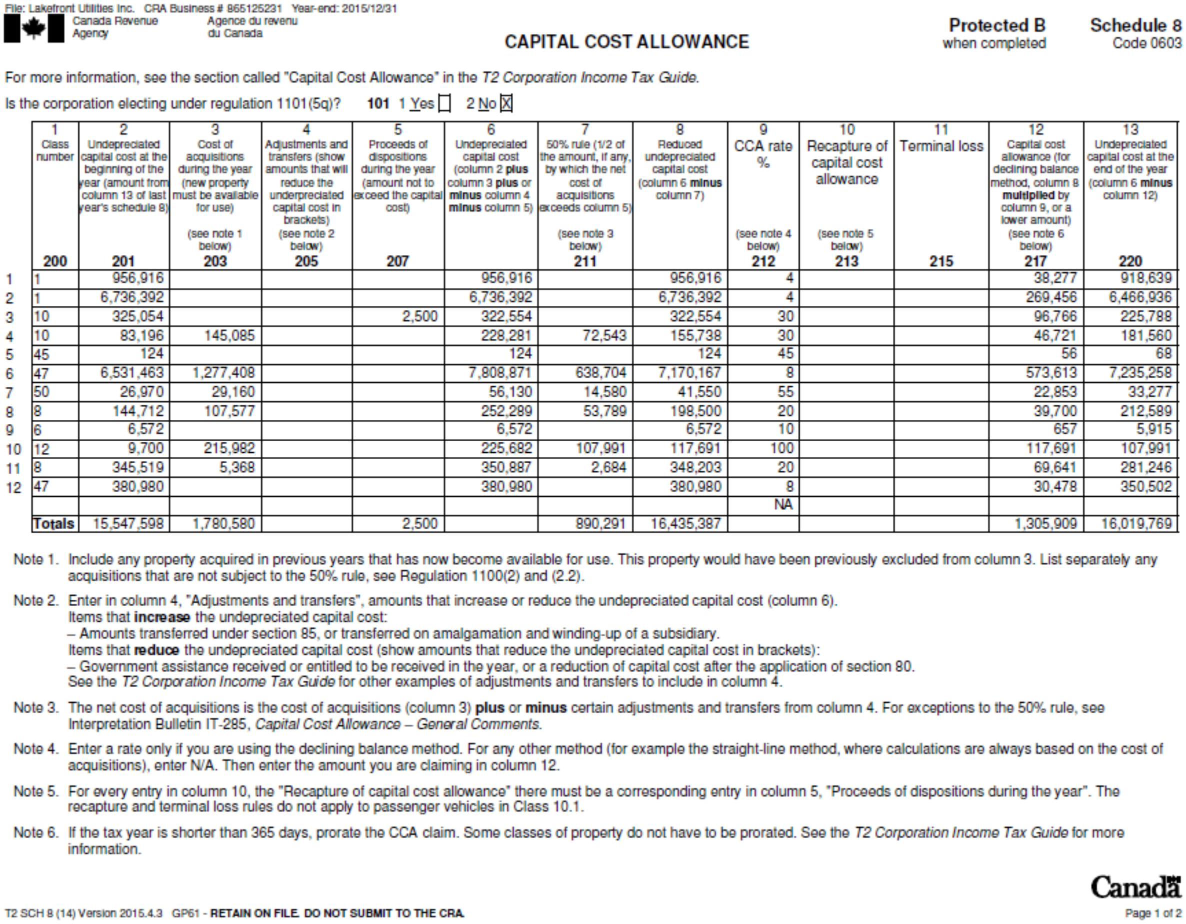
If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation.

Total taxable dividends paid in the tax year to other than connected corporations	450	
Total taxable dividends paid in the tax year for the purposes of a dividend refund (total of column D above **plus** line 450)	460	206,000

Part 4 - Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year for purposes of a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total dividends paid in the tax 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 tax year that qualify for a dividend refund				0



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Canada Revenue Agency
Agence du revenu du Canada

Protected B when completed

Schedule 8 Code 0603

CAPITAL COST ALLOWANCE

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide.*

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number **200**	2 Undepreciated capital cost at the beginning of the year (amount from column 13 of last year's schedule 8) **201**	3 Cost of acquisitions during the year (new property must be available for use) (see note 1 below) **203**	4 Adjustments and transfers (show amounts that will reduce the underpreciated capital cost in brackets) (see note 2 below) **205**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) **207**	6 Undepreciated capital cost (column 2 **plus** column 3 **plus** or **minus** column 4 **minus** column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) (see note 3 below) **211**	8 Reduced undepreciated capital cost (column 6 **minus** column 7)	9 CCA rate % (see note 4 below) **212**	10 Recapture of capital cost allowance (see note 5 below) **213**	11 Terminal loss **215**	12 Capital cost allowance (for declining balance method, column 8 **multiplied** by column 9, or a lower amount) (see note 6 below) **217**	13 Undepreciated capital cost at the end of the year (column 6 **minus** column 12) **220**
1	1	956,916				956,916		956,916	4			38,277	918,639
2	1	6,736,392				6,736,392		6,736,392	4			269,456	6,466,936
3	10	325,054			2,500	322,554		322,554	30			96,766	225,788
4	10	83,196	145,085			228,281	72,543	155,738	30			46,721	181,560
5	45	124				124		124	45			56	68
6	47	6,531,463	1,277,408			7,808,871	638,704	7,170,167	8			573,613	7,235,258
7	50	26,970	29,160			56,130	14,580	41,550	55			22,853	33,277
8	8	144,712	107,577			252,289	53,789	198,500	20			39,700	212,589
9	6	6,572				6,572		6,572	10			657	5,915
10	12	9,700	215,982			225,682	107,991	117,691	100			117,691	107,991
11	8	345,519	5,368			350,887	2,684	348,203	20			69,641	281,246
12	47	380,980				380,980		380,980	8			30,478	350,502
									NA				
	Totals	15,547,598	1,780,580		2,500		890,291	16,435,387				1,305,909	16,019,769

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).

Note 2. Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost (column 6).
Items that **increase** the undepreciated capital cost:
– Amounts transferred under section 85, or transferred on amalgamation and winding-up of a subsidiary.
Items that **reduce** the undepreciated capital cost (show amounts that reduce the undepreciated capital cost in brackets):
– Government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80.
See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

Note 3. The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments.*

Note 4. Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 12.

Note 5. For every entry in column 10, the "Recapture of capital cost allowance" there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

Note 6. If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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CAPITAL COST ALLOWANCE

Additional information for Class 43.1 and 43.2 assets

1 CCA class row number from column 200	2 Type of asset code	3 Province where the asset is located	4 Percentage allocated to the asset

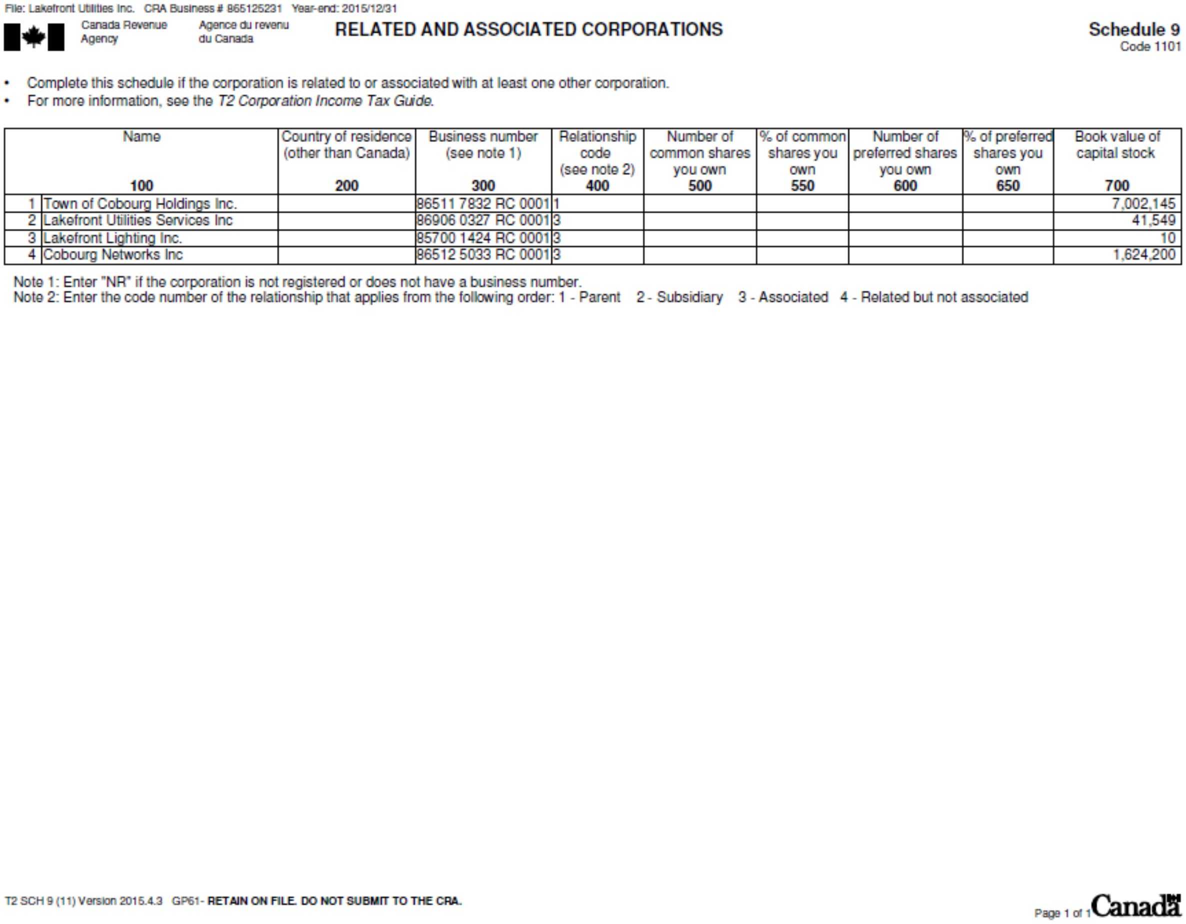
File: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2015/12/31

S8Supp

Reconciliation of NBV and UCC

NBV of capital assets, beginning of year		15,488,047			
Less: Land	-	219,284			
NBV of depreciable capital assets, beginning of year		15,268,763		15,268,763	
UCC beginning of year		15,547,598			
Less: Opening Class 14 balance	-				
Adjusted UCC		15,547,598	-	15,547,598	
Timing difference, beginning of year				(278,835)	A
CCA and amortization					
CCA claimed (except class 14)	+	1,305,909			
Terminal loss	+				
Recapture	-				
Amortization per financial statements	-	1,121,030			
Class 10.1					
Difference on purchase (cost ______ less ceiling ______)	+				
Beginning UCC less CCA in year of disposal	+				
Proceeds from disposal of class 10.1 asset	-				
Gains and losses					
Gain on disposal of capital assets per financial statements	+	2,500			
Capital loss portion of total loss	+				
Loss on disposal of capital assets per financial statements	-				
Capital gain portion of total gain	-				
Other					
Operating leases capitalized for financial statement purposes	+				
Deductible items capitalized for financial statement purposes	+				
Section 85 difference	+				
Pre-valuation day depreciation	+				
Contributions in aid of construction included in revenue but reducing additions on S8	+	106,728			
	+				
Timing difference, current year		294,107	+	294,107	B
Timing difference, end of year (A + B)				15,272	C
Proof					
NBV of capital assets, end of year		16,254,326			
Less: Land	-	219,284			
NBV of depreciable capital assets, end of year		16,035,042		16,035,042	
UCC end of year		16,019,769			
Less: Ending Class 14 balance	-				
Adjusted UCC		16,019,769	-	16,019,769	
Timing difference as at 2015/12/31 (amount D should equal amount C)				15,273	D

Notes



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RELATED AND ASSOCIATED CORPORATIONS

Schedule 9
Code 1101

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name **100**	Country of residence (other than Canada) **200**	Business number (see note 1) **300**	Relationship code (see note 2) **400**	Number of common shares you own **500**	% of common shares you own **550**	Number of preferred shares you own **600**	% of preferred shares you own **650**	Book value of capital stock **700**
1	Town of Cobourg Holdings Inc.		86511 7832 RC 0001	1					7,002,145
2	Lakefront Utilities Services Inc		86906 0327 RC 0001	3					41,549
3	Lakefront Lighting Inc.		85700 1424 RC 0001	3					10
4	Cobourg Networks Inc		86512 5033 RC 0001	3					1,624,200

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11) Version 2015.4.3 GP61- **RETAIN ON FILE. DO NOT SUBMIT TO THE CRA.**

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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** 2015

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 Lighting Inc.	85700 1424 RC 0001	1
5	Cobourg Networks Inc	86512 5033 RC 0001	1

Allocate business limit using: ☒ % ☐ $

	Taxation year		4 Business limit for the year (before the allocation) $	Allocating business limit		
	Start	End		5 Percentage of the business limit (%) **350**	6 Business limit allocated * $ **400**	7 Gross Part I.3 tax for business limit reduction
1	2015/01/01	2015/12/31	500,000	100.000	500,000	
2	2015/01/01	2015/12/31	500,000			
3	2015/01/01	2015/12/31	500,000			
4	2015/01/01	2015/12/31	500,000			
5	2015/01/01	2015/12/31	500,000			
TOTALS				100.000	A 500,000	

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.

File: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2015/12/31

Canada Revenue Agency
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Schedule 33
Code 1402
Protected B
when completed

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.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 Corporation Income Tax Return no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to 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.
- 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 year-end amounts:

Reserves that have not been deducted in calculating 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**	3,926,861	
Contributed surplus	**105**		
Any other surpluses	**106**		
Deferred unrealized foreign exchange gains	**107**		
All loans and advances to the corporation	**108**	203,051	
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	**109**	10,084,888	
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**		
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	**112**		
Subtotal (**add** lines 101 to 112)		19,508,176 ▶	19,508,176 A

Note:
Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if
(a) those lines applied to partnerships in the same manner that they apply to corporations, and
(b) those amounts were computed without reference to amounts owing by the partnership
(i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or
(ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

Part 1 - Capital (continued)

		Subtotal A (from page 1)		19,508,176	A
Deduct the following amounts:					
Deferred tax debit balance at the end of the year	**121**	100,900			
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**				
To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year.	**123**				
Deferred unrealized foreign exchange losses at the end of the year	**124**				
Subtotal (**add** lines 121 to 124)		100,900	▶	100,900	B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")			**190**	19,407,276	

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 payable 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 each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(d)), or another partnership described in paragraph 181.2(4)(d.1)	**406**	
An interest in a partnership (see note 2 below)	**407**	
Investment allowance for the year (add lines 401 to 407)	**490**	

Notes:

1. 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 a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
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. Refer to subsection 181.2(6) for special rules that may apply.

Part 3 - Taxable capital

Capital for the year (line 190)		19,407,276	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**	19,407,276	

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					**Taxable capital employed in Canada**
	19,407,276	x		**610**	289,258 / 289,258	=	**690**	19,407,276

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**	

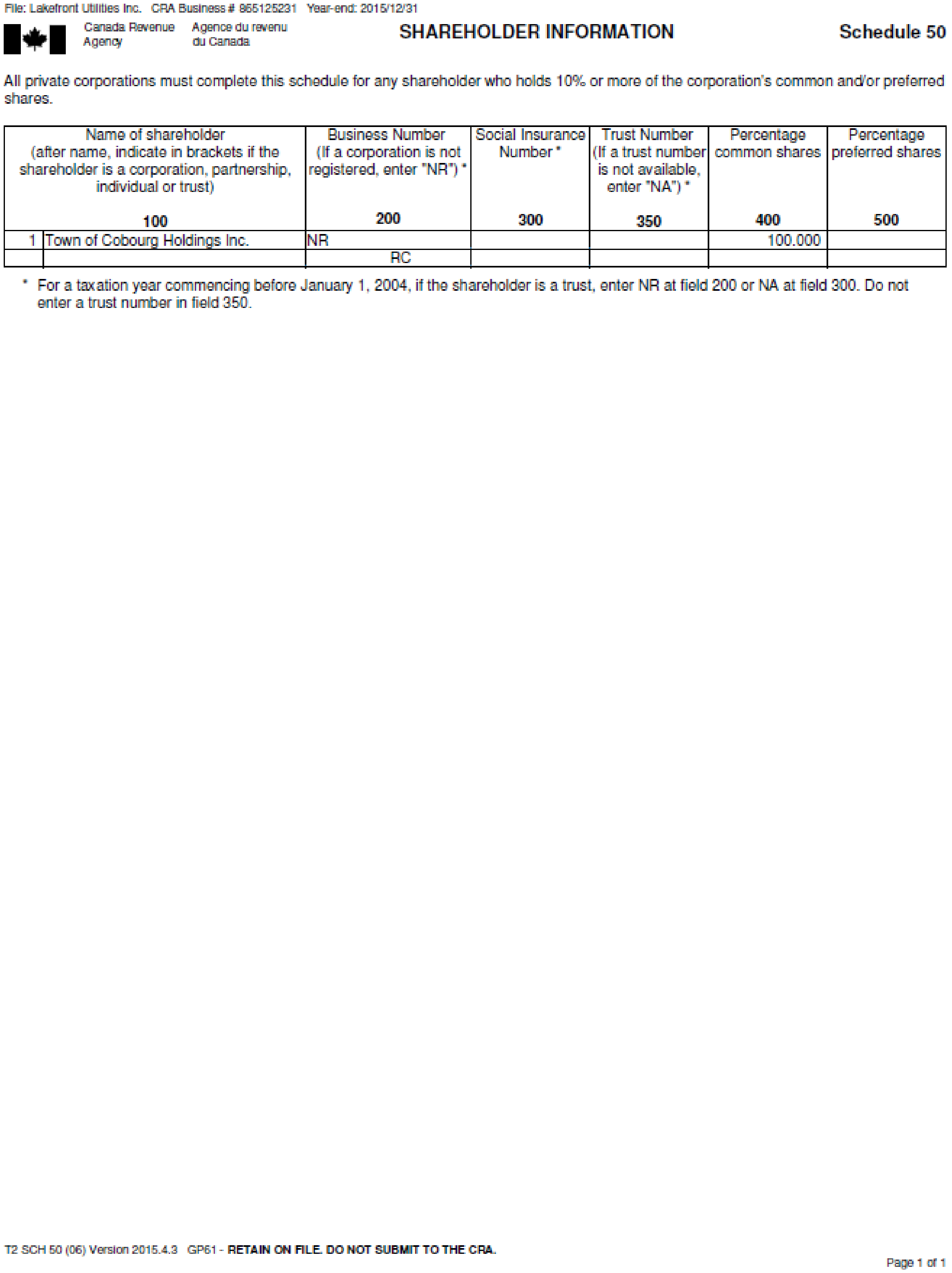
Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

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 (amount from line 690)	19,407,276	F
Deduct:	10,000,000	G
Excess (amount F **minus** amount G) (if negative, enter "0")	9,407,276	H
Calculation for purposes of the small business deduction (amount H × 0.225%)	21,166	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 1501
Protected B
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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.
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Part 1 – General rate income pool (GRIP)

GRIP at the end of the previous tax year **100** 5,218,834 A

Taxable income for the year (DICs enter "0")* **110** 289,258 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 (amount B **minus** amount C) (if negative enter "0"). **150** 289,258

After-tax income (line 150 **multiplied** by 0.72000 (the general rate factor for the tax year)) **190** 208,266 D

Eligible dividends received in the tax year **200** 0

Dividends deductible under section 113 received in the tax year **210** 0

Subtotal (line 200 **plus** line 210) 0 ▶ 0 E

GRIP addition:

Becoming a CCPC (from amount PP in Part 4) **220** 0

Post-amalgamation (total of amounts EE in Part 3 and amounts PP in Part 4) **230** 0

Post-wind-up (total of amounts EE in Part 3 and amounts PP in Part 4) **240** 0

Subtotal (**add** lines 220, 230, and 240) 0 ▶ **290** 0 F

Subtotal (**add** amounts A, D, E, and F) 5,427,100 G

Eligible dividends paid in the previous tax year **300** 0

Excessive eligible dividend designations made in the previous tax year **310** 0

(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 (amount G **minus** amount H) (amount can be negative) **490** 5,427,100

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** 5,427,100

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.

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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			341,256	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** amounts K1, L1, and M1)	0	▶	0	N1		
Subtotal (amount J1 **minus** amount N1) (if negative, enter "0")			341,256	▶	341,256	O1
Taxable income after specified future tax consequences			341,256	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** amounts Q1, R1, and S1)	0	▶	0	T1		
Subtotal (amount P1 **minus** amount T1) (if negative, enter "0")			341,256	▶	341,256	U1
Subtotal (amount O1 **minus** amount U1) (if negative, enter "0")					0	V1

GRIP adjustment for specified future tax consequences to first previous tax year (amount V1 **multiplied** by 0.72000) **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** amounts K2, L2, and M2)	0	▶	0	N2		
Subtotal (amount J2 **minus** amount 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** amounts Q2, R2, and S2)	0	▶	0	T2		
Subtotal (amount P2 **minus** amount T2) (if negative, enter "0")			0	▶	0	U2
Subtotal (amount O2 **minus** amount U2) (if negative, enter "0")					0	V2

GRIP adjustment for specified future tax consequences to second previous tax year (amount V2 **multiplied** by 0.72000) **520** 0

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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** amounts K3, L3, and M3) 0 ▶ 0 N3
Subtotal (amount J3 **minus** amount 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** amounts Q3, R3, and S3) 0 ▶ 0 T3
Subtotal (amount P3 **minus** amount T3) (if negative, enter "0") 0 ▶ 0 U3
Subtotal (amount O3 **minus** amount U3) (if negative, enter "0") 0 V3

GRIP adjustment for specified future tax consequences to third previous tax year (amount V3 **multiplied** by 0.72000) **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 in part 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 (amount BB **minus** amount 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) (amount AA **minus** amount DD) 0 EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE amounts. Enter this total amount on:

– line 230 on page 1 for post-amalgamation; or
– line 240 on page 1 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC

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** amounts 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** amounts JJ to 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 (amount II **minus** amount 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 amounts. 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.

File: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2015/12/31

Canada Revenue Agency Agence du revenu du Canada

Schedule 55
Code 0605

Protected B
when completed

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 - Canadian-controlled private corporations and deposit insurance corporations

Total taxable dividends paid in the tax year	**100**	206,000			
Total eligible dividends paid in the tax year			**150**	0	A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")			**160**	5,427,100	B
Excessive eligible dividend designation (line 150 **minus** line 160)				0	C
Deduct:					
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*			**180**	0	D
Subtotal (amount C **minus** amount D)				0	E
Part III.1 tax on excessive eligible dividend designations - CCPC or DIC (amount E **multiplied** by 20%)			**190**	0	F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 - Other corporations

Total taxable dividends paid in the tax year	**200**	0			
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)				0	G
Deduct:					
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*			**280**	0	H
Subtotal (amount G **minus** amount H)				0	I
Part III.1 tax on excessive eligible dividend designations - Other corporations (amount I **multiplied** by 20%)			**290**	0	J

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

File: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2015/12/31

Canada Revenue Agency
Agence du revenu du Canada

BALANCE SHEET INFORMATION

Schedule 100

Assets	Code	Current year	Prior year
Cash and deposits	**1000**	91,036	1,921,385
Accounts Receivable	1060	2,580,510	2,274,739
Taxes receivable	1066	200,652	280,740
Inventories	1120	243,320	231,824
Work in progress	1125	287,209	297,013
Other current assets	1480	2,932,088	3,553,308
Taxes recoverable / refundable	1483	100,800	151,000
Prepaid expenses	1484	62,680	1,615
Land	1600	219,284	219,284
Buildings	1680	1,020,508	1,201,211
Accumulated amortization of buildings	1681	(60,557)	(210,710)
Other tangible capital assets	1900	16,961,107	24,679,253
Accumulated amortization of other tangible capital assets	1901	(1,886,016)	(10,400,991)
Other deferred items / charges	2424	153,141	289,895
Total assets	**2599**	22,905,762	24,489,566

Liabilities	Code	Current year	Prior year
Bank overdraft	**2600**		
Amounts payable and accrued liabilities	2620	2,987,315	4,241,537
Long term debt	3140	3,084,889	3,765,265
Due to related parties - long-term amounts	3300	7,000,000	7,000,000
Other long term liabilities	3320	203,051	99,404
General provisions / reserves - shown long-term	3325	395,709	293,644
Total liabilities	**3499**	13,670,964	15,399,850

Equity	Code	Current year	Prior year
Common shares	**3500**	5,293,376	5,293,376
Accumulated other comprehensive income	3580	14,561	
Retained earnings / deficit	**3600**	3,926,861	3,796,340
Total equity	**3620**	9,234,798	9,089,716
Total liabilities and equity	**3640**	22,905,762	24,489,566

Retained earnings	Code	Current year	Prior year
Retained earnings/deficit-start	**3660**	3,796,340	3,643,724
Net income / loss *	**3680**	487,792	412,716
Cash dividends	3701	(206,000)	(260,100)
Prior period adjustments	3720	(151,271)	
Total retained earnings	**3849**	3,926,861	3,796,340

* The amount on line 3680 must equal the amount on line 9999 of S125 or S140 without considering line 9998.

File: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2015/12/31

Canada Revenue Agency
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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 ______

Sequence number
0003 ______

Revenue	Code	Current year	Prior year
Trade sales of goods and services	**8000**	4,132,096	4,190,437
Total sales of goods and services	**8089**	4,132,096	4,190,437
Other revenue	8230	484,326	491,943
Realized gains / losses on disposal of assets	8210	2,500	(11,230)
Interest from other Canadian sources	8094	101,756	
Total revenue	**8299**	4,720,678	4,671,150

Cost of sales	Code	Current year	Prior year
Opening inventory	**8300**		
Cost of sales	**8518**		
Gross profit / loss (item 8089 - item 8518)	**8519**	4,132,096	4,190,437

Operating expenses	Code	Current year	Prior year
Amortization of tangible assets	8670	1,121,030	932,271
Interest and bank charges	8710	175,531	185,626
Interest on long term debt	8714	507,500	507,500
General and administrative expenses	9284	2,299,291	2,496,101
Donations	8522	5,389	5,476
Total operating expenses	**9367**	4,108,741	4,126,974
Total expenses	**9368**	4,108,741	4,126,974
Net non-farming income	**9369**	611,937	544,176

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**	611,937	544,176

Other comprehensive income

Revaluation surplus	**7000**				
Defined benefit gains/losses	**7002**	+	14,561	+	
Foreign operation translation gains/losses	**7004**	+		+	
Equity instruments gains/losses	**7006**	+		+	
Cash flow hedge effective portion gains/losses	**7008**	+		+	
Income tax relating to components of other comprehensive income	**7010**	+		+	
Miscellaneous other comprehensive income	**7020**	+		+	
Total - Other comprehensive income		=	14,561	=	

Summary

Complete this section if only one Schedule 125 is filed, Schedule 140 is used to summarize the information from multiple Schedules 125.

T2 SCH 125 Version 2015.4.3 GP61 - **RETAIN ON FILE. DO NOT SUBMIT TO THE CRA.**

File: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2015/12/31

Extraordinary items	**9975**	-		-	
Legal settlements	**9976**	-		-	
Unrealized gains / losses	**9980**	+		+	
Unusual items	**9985**	-		-	
Current income taxes	**9990**	-	79,245	-	77,760
Future income tax provision	**9995**	-	44,900	-	53,700
Total - Other comprehensive income	**9998**	+	14,561	+	
Net income / loss after taxes and extraordinary items	**9999**	=	502,353	=	412,716

File: Lakefront Utilities Inc. CRA Business # 865125231 Year-end: 2015/12/31

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Schedule 141
Code 1002

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. 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.
- For more information, see Guide RC4088, *General Index of Financial Information* (GIFI) and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? **095** 1 Yes ☒ 2 No ☐

Is the accountant connected* with the corporation? **097** 1 Yes ☐ 2 No ☒

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note:
If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report 1 ☒
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 ☒

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 ☒ 2 No ☐

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? **104** 1 Yes ☐ 2 No ☒
Is re-evaluation of asset information mentioned in the notes? **105** 1 Yes ☐ 2 No ☒
Is contingent liability information mentioned in the notes? **106** 1 Yes ☐ 2 No ☒
Is information regarding commitments mentioned in the notes? **107** 1 Yes ☒ 2 No ☐

Does the corporation have investments in joint venture(s) or partnership(s)? **108** 1 Yes ☐ 2 No ☒

1

2

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? **200** 1 Yes ☐ 2 No ☐

If **yes**, enter the amount recognized:		**In net income** Increase(decrease)		**In OCI** Increase (decrease)
Property, plant, and equipment	**210**		**211**	
Intangible assets	**215**		**216**	
Investment property	**220**			
Biological assets	**225**			
Financial instruments	**230**		**231**	
Other	**235**		**236**	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? **250** 1 Yes ☐ 2 No ☐

Did the corporation apply hedge accounting during the tax year? **255** 1 Yes ☐ 2 No ☐

Did the corporation discontinue hedge accounting during the tax year? **260** 1 Yes ☐ 2 No ☐

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? **265** 1 Yes ☐ 2 No ☐

If **yes**, you have to maintain a separate reconciliation.

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Schedule 500
Protected B
when completed

Ontario Corporation Tax Calculation

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only. You do not have to file it with your *T2 Corporation Income Tax Return*.

Part 1 – Ontario basic rate of tax for the year

Ontario basic rate of tax for the year 11.5 % A

Part 2 - Calculation of Ontario basic income tax

Ontario taxable income * 289,258 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A from Part 1) 33,265 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 or Ontario special additional tax on life insurance corporations 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.

Protected B
when completed

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)	289,258	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)	289,258	2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)	500,000	3

Ontario business limit reduction:

Amount from line 3 500,000 a

Deduct:

Amount from line E on page 4 of the T2 return 1,088,222 x Number of days in the tax year after May 1, 2014 365 / Number of days in the tax year 365 = 500,000 b

Reduced Ontario business limit (amount a **minus** amount b) (if negative, enter "0") ▶ 4

Enter the least of amounts 1, 2, 3 and 4 D

Ontario domestic factor (ODF): Ontario taxable income * / Taxable income earned in all provinces and territories ** 289,258 / 289,258 = 1.00000 E

Amount D x ODF (line E) c

Ontario taxable income (amount B from Part 2) 289,258 d

Ontario small business income (lesser of amount c and amount d)		F
OSBD rate for the year	7.0 %	G
Ontario small business deduction: amount F **multiplied** by rate G		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.

Part 4 - 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.

Ontario adjusted small business income (lesser of amount D and amount d from Part 3) I

Enter amount I on line K in Part 5 of this schedule or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Protected B
when completed

Part 5 - Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17		J
Deduct:		
Ontario adjusted small business income (amount I from Part 4)		K
Subtotal (amount J **minus** amount K) (if negative, enter "0")		L
Amount L **multiplied** by rate G from Part 3		M
Ontario domestic factor (line E from Part 3)	1.00000	N
Ontario credit union tax reduction (amount M **multiplied** by ODF from line N)		O

Enter amount O on line 410 on Schedule 5.

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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: Ontario

110 Date of incorporation or amalgamation, whichever is the most recent: 2000/05/01

120 Ontario Corporation No.: 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: 207

220 Street name/Rural route/Lot and Concession number: Division Street

230 Suite number:

240 Additional address information if applicable (line 220 must be completed first):

250 Municipality (e.g., city, town): Cobourg

260 Province: ON

270 Country: CA

280 Postal code: 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 Paul (Last name) **451** Dereck (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.

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

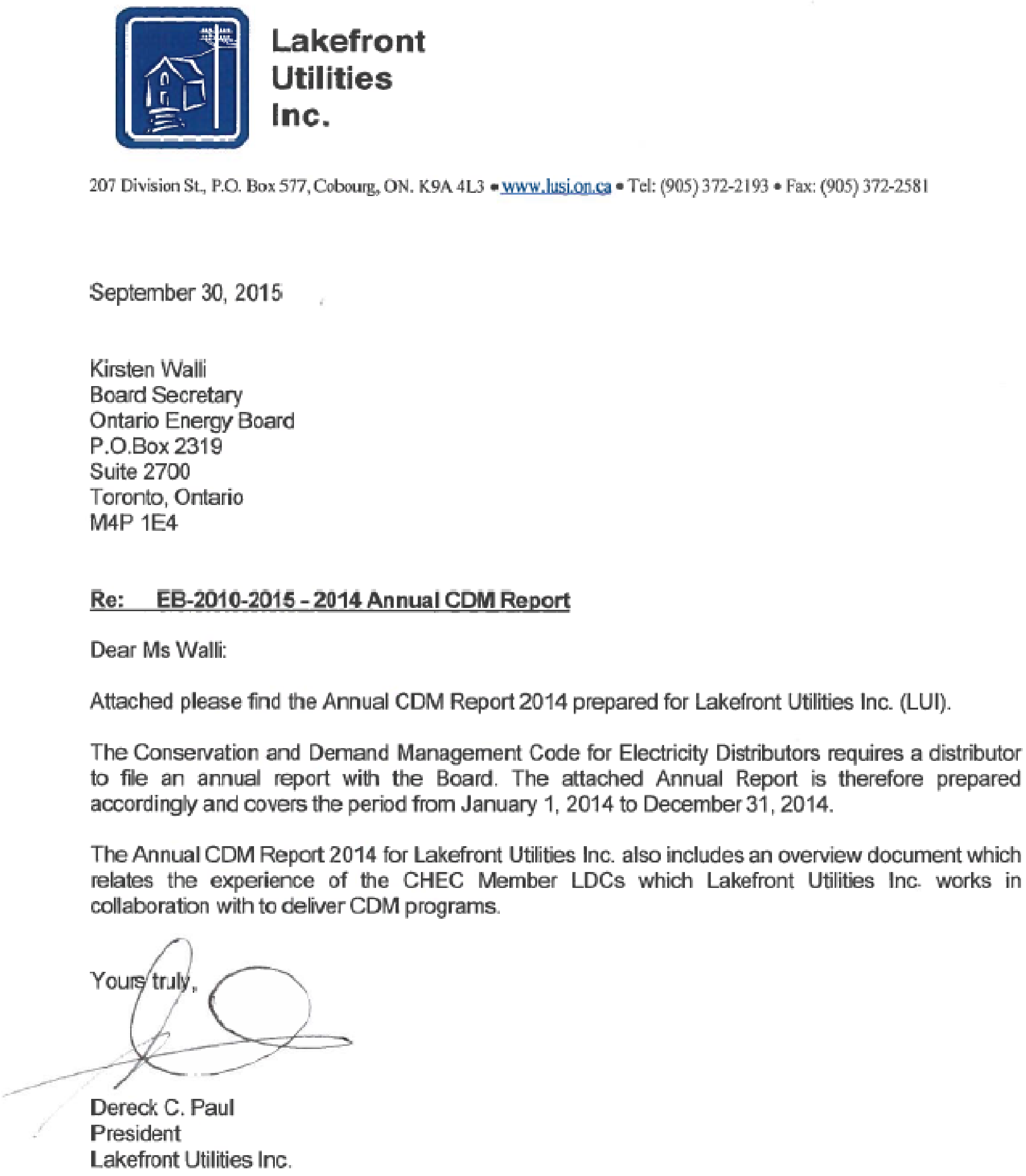
580 Country

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.

Attachment D - 2011-2014 Final CDM Results



Lakefront
Utilities
Inc.

207 Division St., P.O. Box 577, Cobourg, ON. K9A 4L3 • www.lusi.on.ca • Tel: (905) 372-2193 • Fax: (905) 372-2581

September 30, 2015

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O.Box 2319
Suite 2700
Toronto, Ontario
M4P 1E4

Re: EB-2010-2015 - 2014 Annual CDM Report

Dear Ms Walli:

Attached please find the Annual CDM Report 2014 prepared for Lakefront Utilities Inc. (LUI).

The Conservation and Demand Management Code for Electricity Distributors requires a distributor to file an annual report with the Board. The attached Annual Report is therefore prepared accordingly and covers the period from January 1, 2014 to December 31, 2014.

The Annual CDM Report 2014 for Lakefront Utilities Inc. also includes an overview document which relates the experience of the CHEC Member LDCs which Lakefront Utilities Inc. works in collaboration with to deliver CDM programs.

Yours truly,

Dereck C. Paul
President
Lakefront Utilities Inc.

Cornerstone Hydro Electric Concepts (CHEC)

Combined Conservation and Demand Management Annual Report 2014

EB-2010-0215

Collaboration for Conservation

GODERICH HYDRO
ORILLIAPOWER
Energizing Our Community
PARRY SOUND POWER
Collus PowerStream
WNP
Wellington North Power Inc.
TOWNSHIP OF CENTRE WELLINGTON
UNITY IS STRENGTH
HYDRO
innpower
Lakefront Utilities Inc.
PUC
MIDLAND POWER UTILITY CORPORATION
LakelandPower
of POWER
ORANGEVILLE HYDRO
WASAGA
DISTRIBUTION INC.
RIDEAU ST. LAWRENCE
DISTRIBUTION INC.

September 30, 2015

Cornerstone Hydro Electric Concepts Association Inc.

Executive Summary:

This report represents the 2014 annual reporting as required by the CDM Code for 13 of the 15 CHEC Association LDCs. The results and comments provided in this overview section are based on the combined experience of the CHEC LDCs.

The report format contains an overview section relating the combined experience of CHEC LDCs and thirteen addendums containing the individual LDC Annual CDM Reports. The overview section provides a summary of the overall target achieved, conditions impacting strategy progress and tracking of the CDM Strategy.

In the fourth year of the program the residential portfolio performed better than in previous years on an incremental level. The residential program experienced improved kW performance over the previous year. Three programs contributed to the demand which included: Coupons, HVAC and the *peaksaver*PLUS® Initiative which showed a marked improvement. Energy contribution to target on an incremental basis was much improved in the final year. The coupon initiative experienced significant growth contributing approximately a third of the total energy savings from coupons in 2014. The HVAC initiative continued to show good performance remaining fairly consistent across the framework period. The Low Income Initiative performed below expectations. The ability to engage eligible customers has been difficult in this program.

The Demand Response (DR) Initiative contribution to the targets was finalized in the last year of the framework. A number of LDCs had customers enrol in DR but then exit prior to the end of the framework. Any future DR initiative, if offered, will require designs which maintain the customer's interest and provides customer benefit over the longer term.

The Commercial and Institutional program continues to be a significant contributor to targets achieved. This portfolio accounts for 43% of the kWh achieved to the end of 2014. The retrofit initiative along with the Direct Installed Lighting Initiative continues to provide savings and continues to be of interest to the customers. The Direct Installed Lighting Initiative, which is focused primarily on lighting, is approaching market saturation and will need some renewal to maintain traction in the sector. The Retrofit Initiative continues to experience good participation and is well established in the conservation industry. It is anticipated that the Retrofit Initiative will continue to achieve energy and demand savings if offered in the future.

CHEC maintained the Roving Energy Manager (REM) position throughout 2014. The position has demonstrated value with successful approaches to industry and commercial customers. The REM continues to be instrumental in supporting CHEC LDCs and their commercial customers to identify potential savings and to implement projects. The REM's ability to work with customers has a direct impact on retrofit and monitoring projects. A number of audit projects have been initiated which are anticipated to provide savings in future frameworks.

The combined strategy results (Table 4) indicate that the demand reduction is below the 2014 Revised Projection by a couple of percent. The combined achieved demand at 61.1% of target is slightly below the provincial achieved demand reduction of 69.8%. The combined energy reduction is ahead of the 2014 Revised Projection by approximately 20% for a total of 110.7% of target which compares with the provincial achieved energy reduction of 109.2%.

1.0 Introduction:

Cornerstone Hydro Electric Concepts Association (CHEC) is an association of fifteen (15) Local Distribution Companies (LDCs) (in 2014). The CHEC member LDCs have prepared this Conservation and Demand Management (CDM) Annual Report 2014 as required by the Conservation and Demand Management Code for Electricity Distributors. The report is a collaborative initiative of 13 of the CHEC member LDCs. The report is consistent with the combined CDM Strategy filed in November 2010 and includes Orillia Power as of 2012 reporting.

1.1 Distributors Included in CHEC Association CDM Strategy:

CHEC LDCs work collaboratively to meet regulatory and operational requirements. The Association facilitates LDCs' abilities to address initiatives in a cost effective manner, sharing information, expertise and resources. The development of a collaborative CDM Strategy and the subsequent CDM Annual Report is consistent with the CHEC philosophy of working together to meet the needs of the member LDCs and to work effectively for the customers served.

The LDCs, all members of CHEC, covered under this CDM Annual Report include:

- Centre Wellington Hydro Ltd.
- COLLUS PowerStream (COLLUS Power)
- InnPower Corporation (Innisfil Hydro Distribution Systems Limited)
- Lakefront Utilities Inc.
- Lakeland Power Distribution Ltd.
- Midland Power Utility Corporation
- Orangeville Hydro Limited
- Orillia Power Distribution Corporation
- Parry Sound Corporation (Now merged with Lakeland Power)
- Rideau St. Lawrence Distribution Inc.
- Wasaga Distribution Inc.
- Wellington North Power Inc.
- West Coast Huron Energy Inc. (Goderich Hydro).

CHEC LDCs have worked collaboratively and as part of the Association since 2000. The CHEC Combined Annual CDM Report includes an overview section and separate addendums for each LDC. The LDC addendum format follows the provincial template.

2.0 CDM Targets for Electricity Demand (MW) and Electricity Consumption (GWh):

The CDM target for each LDC has been established by the Ontario Energy Board (OEB) utilizing a methodology developed by the Ontario Power Authority (OPA). The targets were later revised and incorporated into the LDC license requirements. Table 1 illustrates the final targets for each LDC.

Table 1 – OEB Defined Targets

	MW	GWH
LDC	**Revised Target**	**Revised Target**
Centre Wellington Hydro	1.64	7.81
COLLUS Power	3.14	14.97
Innisfil Hydro	2.5	9.2
Lakefront Utilities	2.77	13.59
Lakeland Power	2.32	10.18
Midland Power	2.39	10.82
Orangeville Hydro	2.78	11.82
Orillia Power	3.07	15.05
Parry Sound Power	0.74	4.16
Rideau St. Lawrence	1.22	5.1
Wasaga Distribution	1.34	4.01
Wellington North Power	0.93	4.52
West Coast Huron Energy	0.88	8.28
Total	**25.72**	**119.51**

3.0 Progress toward Achieving Target

Table 2 and Table 3 provide summaries of the progress made by CHEC LDCs in 2014 towards the combined demand and energy targets. The combined results are the summation for the 13 member LDCs and represent reported savings as per the IESO. The individual savings for each LDC are represented in the associated Addendum.

Table 2 Combined Net Demand Savings at End User Level Including DR Contribution

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	5.1	2.3	2.3	2.1
2012 - Verified†	0.0	4.6	2.3	2.3
2013 - Verified†	0.0	0.0	5.9	2.1
2014 - Verified†	0.0	0.0	0.0	9.3
Verified Net Annual Peak Demand Savings Persisting in 2014:				15.7
Combined CHEC 2014 Annual CDM Capacity Target:				25.7
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				**61.1%**

†Includes adjustments to previous years' verified results
Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Contribution toward the peak target at the end of the framework, while slightly below the revised prediction is in the general range anticipated.

Table 3 Combined Net Energy Savings at End User Level

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	10.5	10.4	10.4	9.7	41.0
2012 - Verified†		10.0	9.9	9.8	30.1
2013 - Verified†	0.0	0.0	9.5	9.4	19.9
2014 - Verified†	0.0	0.0		24.9	41.3
Verified Net Cumulative Energy Savings 2011-2014:					132.4
Combined CHEC 2011-2014 Cumulative CDM Energy Target:					119.5
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					**110.7%**

†Includes adjustments to previous years' verified results

Incremental energy savings in 2014 continue to be strong when compared to other years in the framework. Performance was generally as predicted in the revised strategy document for 2014. The total achieved energy savings exceed the target with a total of 110.7%. A large portion of the kWh achieved was due to one project which added approximately 16% of the target. This clearly illustrates the impact that a given project can have on results.

4.0 General Conditions Impacting Strategy Performance:

This section outlines issues which have impacted on the progress of Strategies and some of the general lessons learned over the fourth year of the program. While there have been many successes there remain many challenges within the CDM portfolio and specific challenges in some service territories. These specifics are outlined in the LDC specific reports contained in the addendums.

4.1 Portfolio Reduction and OEB Approved Programs:

As stated in previous reports the overall portfolio reduction as a result of midstream and OEB approved programs not being developed has reduced the overall potential to achieve target. The commercial programs aimed at demand, namely DR1 and DR3 were either never in market or withdrawn part way through the framework. The in-market initiatives, which were generally focused on kWh savings, did meet target on a provincial basis.

4.2 Roving Energy Manager:

CHEC LDCs collaborative application for a Roving Energy Manager (REM) provided an excellent resource to assist LDCs and their customers in the investigation and implementation of energy savings projects. The REM has been active across the CHEC LDC service territories and truly represents a "roving energy manager". The REM has consistently met program requirements for target resulting in contract renewal. As noted in previous reports, the delay in funding approval impacted on the initial start of the REM. An earlier start would have seen more projects implemented within the current framework, recognizing that the lead time for commercial and industrial projects can be extensive. The lead time for projects has pushed out the final implementation of many projects beyond December 31, 2014 but the resultant savings will be accounted for in the Conservation First Framework.

4.3 Residential Program Performance:

The residential programs performed well over 2014 as compared to other years in the framework and exceeded the projected performance for 2014.

The Appliance Retirement Initiative, while being in the market for several years and showing some signs of saturation, did produce results similar to 2013. Perhaps the impending termination of the program produced additional savings with customers taking part in the program prior to the final date.

The Coupon Initiative experienced significant growth in 2014 contributing approximately a third of the total energy savings from coupons in the final year. The continued performance of coupons clearly illustrates the value of this customer outreach in the residential sector. Experience over the course of the program has clearly indicated that continued promotion of the coupons, coupons being in market over the course of the year and evaluation of spillover impact has maintained the continued value of the coupon program.

The Low Income Initiative did not meet savings expectations in the final year nor did it meet the four year expectation. The challenge to engage eligible customers as well as issues around self-identification presented difficulties with obtaining the required traction for this program. In many instances the ability to obtain deep installs has been challenging.

Within the funding envelope provided for conservation programs there was limited opportunity to fund general conservation education programs. While specific marketing of programs was undertaken this does not replace education initiatives. With the focus on target achievement, investment in educational programs where savings may be difficult to quantify was not undertaken. In future frameworks the ability to incorporate educational programs, in a cost effective manner, may be an area for investigation.

4.4 Peaksaver Plus:

The Residential Demand Response Initiative (*peaksaver* PLUS®) has been identified in most strategies as being a key contributor to obtaining significant peak demand target from the residential sector. This program has fallen well below initial performance target achievement expectations.

CHEC LDCs released an RFP for a supplier of service and technology in late 2012. Issues with respect to launching the program moved the in-market date later than anticipated including postponement into 2014 awaiting communication capabilities for some LDCs. Further complicating the issue was the need to terminate installation as colder weather approached to avoid completing the initial test installations when the AC would not be operating. The benefits of the "in home devices" as part of this program did not meet expectations as it was determined that there was no statistically valid energy savings from these devices. This finding impacted on the kWh savings which had been planned for in the initial CDM Strategies.

4.5 CDM Awareness:

The continued offering of conservation programs has raised the general awareness and readiness to participate among customers. Customer experience within one program appears to foster continued participation as opportunities present themselves.

Within the residential portfolio, as programs continue or special offerings are repeated, customers appear to be "looking towards" the program. This should assist with marketing efforts and make the resulting participation easier on a go forward basis. Of course to maintain this interest offerings need to be continually revised to ensure they are meeting both the customer expectations and technology advancements as well as producing savings for LDCs.

4.6 Commercial Programs:

The Direct Installed Lighting Initiative has been in market for some time however continued to show good performance in 2014. The ability to achieve results in this program was assisted by the addition of LED lamps and continued out-reach to customers who have not participated.

The Retrofit Initiative continues to be a stable and important program delivering approximately 60% of the 2014 energy savings. The program has significant traction within the sector with opportunities being pursued in a variety of technologies. As noted previously the Roving Energy Manager has been active in supporting LDC efforts with their customers and the Retrofit Initiative provides an excellent tool for the REM to use in assisting customers with implementation of energy efficiency projects.

4.8 DR 3 Contribution:

Within the strategies filed by CHEC LDCs, DR 3 accounted for approximately 3.4 MW of demand. In evaluating the demand contribution of various programs it is apparent that DR 3 or a similar demand focused program is required to obtain the demand reduction. Early in the framework customers participated in the DR3 program however over the course of the framework a number withdrew from the program. Overall a total of 2.6 MW of demand was obtained through the DR 3 Program.

5.0 Variation from CDM Strategy:

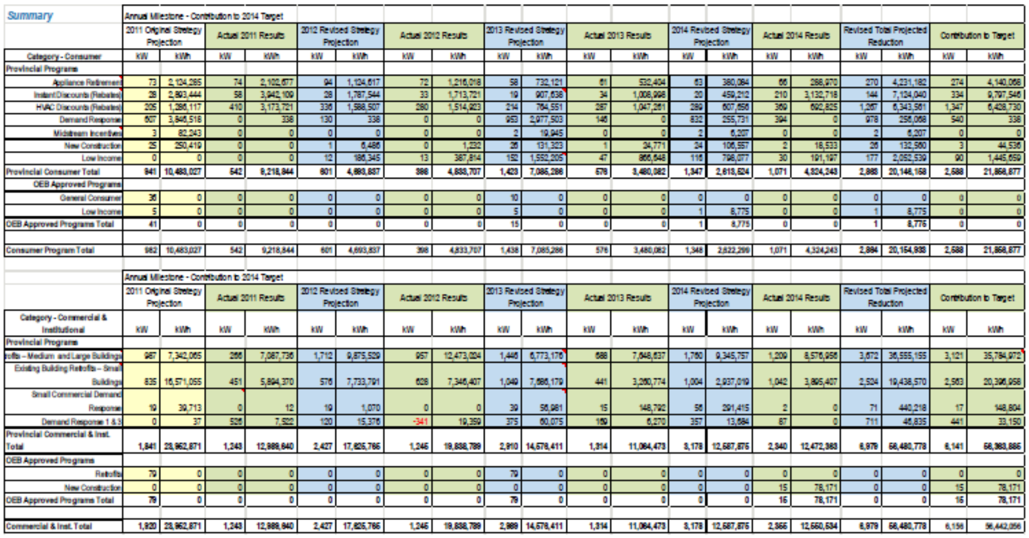
The Addendums for each LDC include tracking of the CDM Strategy. A number of the LDCs have modified their strategies based on their results to the end of 2013. The combined strategy for the 13 CHEC LDCs is summarized in Table 4.

The final results are slightly below the expected demand savings while energy achieved savings exceed the expected results by about 20%. The impact of one project increased the energy savings by approximately 16%. Without this project included the combined strategy savings is 94.9 approximately 3% above the revised strategy expectation.

CHEC LDCs remain committed to CDM and obtaining kW and kWh savings. The experience gained and relationships developed in the 2011-2014 Framework will assist CHEC LDCs within the Conservation First Framework.

The specific activities associated with each LDC are outlined in the attached Addendums.

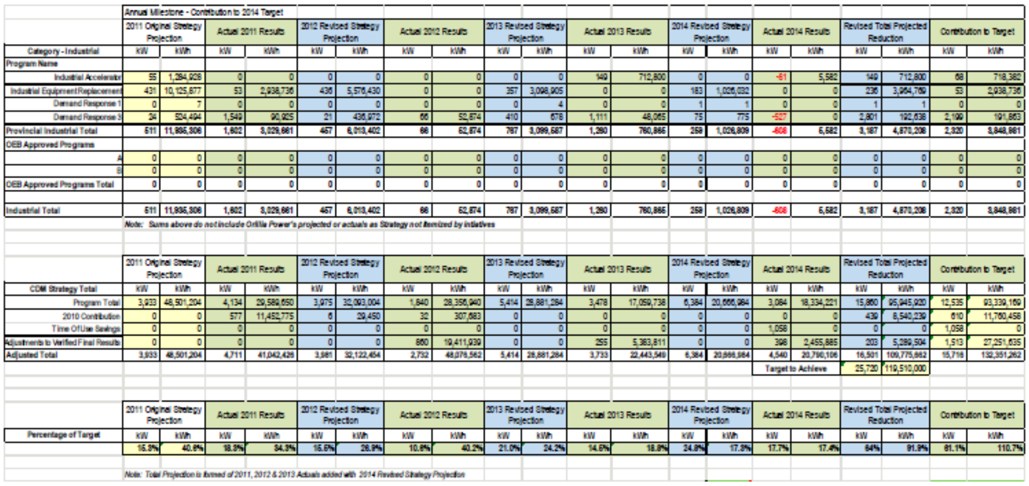
Table 4 – CHEC CDM Combined Strategy:



Summary	Annual Milestone - Contribution to 2014 Target																			
	2011 Original Strategy Projection		Actual 2011 Results		2012 Revised Strategy Projection		Actual 2012 Results		2013 Revised Strategy Projection		Actual 2013 Results		2014 Revised Strategy Projection		Actual 2014 Results		Revised Total Projected Reduction		Contribution to Target	
Category - Consumer	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh
Provincial Programs																				
Appliance Retirement	73	2,124,285	74	2,102,677	94	1,124,617	72	1,216,018	58	732,121	61	532,404	63	380,084	66	288,970	270	4,231,182	274	4,140,068
Instant Discounts (Rebates)	28	2,893,444	58	3,942,109	28	1,787,544	33	1,713,721	19	907,638	34	1,008,998	20	459,212	210	3,132,718	144	7,124,040	334	9,797,546
HVAC Discounts (Rebates)	205	1,286,117	410	3,173,721	336	1,588,507	280	1,514,923	214	764,551	287	1,047,261	289	607,656	369	692,825	1,267	6,343,561	1,347	6,428,730
Demand Response	607	3,846,518	0	338	130	338	0	0	953	2,977,503	146	0	832	255,731	394	0	978	256,068	540	338
Midstream Incentives	3	82,243	0	0	0	0	0	0	2	19,945	0	0	2	6,207	0	0	2	6,207	0	0
New Construction	25	250,419	0	0	1	6,486	0	1,232	26	131,323	1	24,771	24	106,557	2	18,533	26	132,560	3	44,536
Low Income	0	0	0	0	12	186,345	13	387,814	152	1,552,205	47	866,648	116	798,077	30	191,197	177	2,052,539	90	1,445,659
Provincial Consumer Total	941	10,483,027	542	9,218,844	601	4,693,837	398	4,833,707	1,423	7,085,286	576	3,480,082	1,347	2,613,524	1,071	4,324,243	2,888	20,146,158	2,588	21,856,877
OEB Approved Programs																				
General Consumer	36	0	0	0	0	0	0	0	10	0	0	0	0	0	0	0	0	0	0	0
Low Income	5	0	0	0	0	0	0	0	5	0	0	0	1	8,775	0	0	1	8,775	0	0
OEB Approved Programs Total	41	0	0	0	0	0	0	0	15	0	0	0	1	8,775	0	0	1	8,776	0	0
Consumer Program Total	982	10,483,027	542	9,218,844	601	4,693,837	398	4,833,707	1,438	7,085,286	576	3,480,082	1,348	2,622,299	1,071	4,324,243	2,884	20,154,933	2,588	21,856,877

	Annual Milestone - Contribution to 2014 Target																			
	2011 Original Strategy Projection		Actual 2011 Results		2012 Revised Strategy Projection		Actual 2012 Results		2013 Revised Strategy Projection		Actual 2013 Results		2014 Revised Strategy Projection		Actual 2014 Results		Revised Total Projected Reduction		Contribution to Target	
Category - Commercial & Institutional	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh
Provincial Programs																				
rofits – Medium and Large Buildings	987	7,342,065	266	7,087,736	1,712	9,875,529	957	12,473,024	1,446	6,773,176	688	7,648,637	1,760	9,345,757	1,209	8,576,958	3,672	36,555,155	3,121	35,784,972
Existing Building Retrofits – Small Buildings	835	16,571,055	451	5,894,370	576	7,733,791	628	7,346,407	1,049	7,686,179	441	3,260,774	1,004	2,937,019	1,042	3,895,407	2,524	19,438,570	2,563	20,396,958
Small Commercial Demand Response	19	39,713	0	12	19	1,070	0	0	39	56,981	15	148,792	58	291,415	2	0	71	440,218	17	148,804
Demand Response 1 & 3	0	37	526	7,522	120	15,376	-341	19,359	375	60,075	159	6,270	357	13,684	87	0	711	46,835	441	33,150
Provincial Commercial & Inst. Total	1,841	23,952,871	1,243	12,989,640	2,427	17,625,766	1,245	19,838,789	2,910	14,576,411	1,314	11,064,473	3,178	12,587,875	2,340	12,472,365	6,978	56,480,778	6,141	56,363,885
OEB Approved Programs																				
Retrofits	79	0	0	0	0	0	0	0	79	0	0	0	0	0	0	0	0	0	0	0
New Construction	0	0	0	0	0	0	0	0	0	0	0	0	0	0	15	78,171	0	0	15	78,171
OEB Approved Programs Total	79	0	0	0	0	0	0	0	79	0	0	0	0	0	16	78,171	0	0	16	78,171
Commercial & Inst. Total	1,920	23,952,871	1,243	12,989,640	2,427	17,625,766	1,245	19,838,789	2,989	14,576,411	1,314	11,064,473	3,178	12,587,875	2,356	12,550,534	6,978	56,480,778	6,156	56,442,056

Cornerstone Hydro Electric Concepts Association



	Annual Milestone - Contribution to 2014 Target																			
	2011 Original Strategy Projection		Actual 2011 Results		2012 Revised Strategy Projection		Actual 2012 Results		2013 Revised Strategy Projection		Actual 2013 Results		2014 Revised Strategy Projection		Actual 2014 Results		Revised Total Projected Reduction		Contribution to Target	
Category - Industrial	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh
Program Name																				
Industrial Accelerator	55	1,284,928	0	0	0	0	0	0	0	0	149	712,800	0	0	-61	5,582	149	712,800	68	718,382
Industrial Equipment Replacement	431	10,125,877	53	2,938,736	436	5,576,430	0	0	357	3,098,905	0	0	183	1,026,032	0	0	236	3,964,769	53	2,938,736
Demand Response 1	0	7	0	0	0	0	0	0	0	4	0	0	1	1	0	0	1	1	0	0
Demand Response 3	24	524,494	1,549	90,925	21	436,972	66	52,874	410	678	1,111	48,065	75	775	-527	0	2,801	192,638	2,199	191,863
Provincial Industrial Total	**511**	**11,935,306**	**1,602**	**3,029,661**	**457**	**6,013,402**	**66**	**52,874**	**767**	**3,099,587**	**1,260**	**760,865**	**259**	**1,026,808**	**-588**	**5,582**	**3,187**	**4,870,208**	**2,320**	**3,848,981**
OEB Approved Programs																				
A	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
B	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OEB Approved Programs Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Industrial Total	**511**	**11,935,306**	**1,602**	**3,029,661**	**457**	**6,013,402**	**66**	**52,874**	**767**	**3,099,587**	**1,260**	**760,865**	**259**	**1,026,808**	**-588**	**5,582**	**3,187**	**4,870,208**	**2,320**	**3,848,981**

Note: Sums above do not include Orillia Power's projected or actuals as Strategy not itemized by initiatives

	2011 Original Strategy Projection		Actual 2011 Results		2012 Revised Strategy Projection		Actual 2012 Results		2013 Revised Strategy Projection		Actual 2013 Results		2014 Revised Strategy Projection		Actual 2014 Results		Revised Total Projected Reduction		Contribution to Target	
CDM Strategy Total	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh
Program Total	3,933	48,501,204	4,134	29,589,650	3,975	32,093,004	1,840	28,356,940	5,414	28,881,284	3,478	17,059,738	6,384	20,666,984	3,084	18,334,221	15,860	95,945,920	12,535	93,339,169
2010 Contribution	0	0	577	11,452,775	6	29,450	32	307,683	0	0	0	0	0	0	0	0	439	8,540,239	610	11,760,458
Time Of Use Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,058	0	0	0	1,058	0
Adjustments to Verified Final Results	0	0	0	0	0	0	860	19,411,939	0	0	255	5,383,811	0	0	398	2,455,885	203	5,289,504	1,513	27,251,635
Adjusted Total	3,933	48,501,204	4,711	41,042,425	3,981	32,122,454	2,732	48,076,562	5,414	28,881,284	3,733	22,443,549	6,384	20,666,984	4,540	20,790,106	16,501	109,775,662	15,716	132,351,262
															Target to Achieve		25,720	119,510,000		

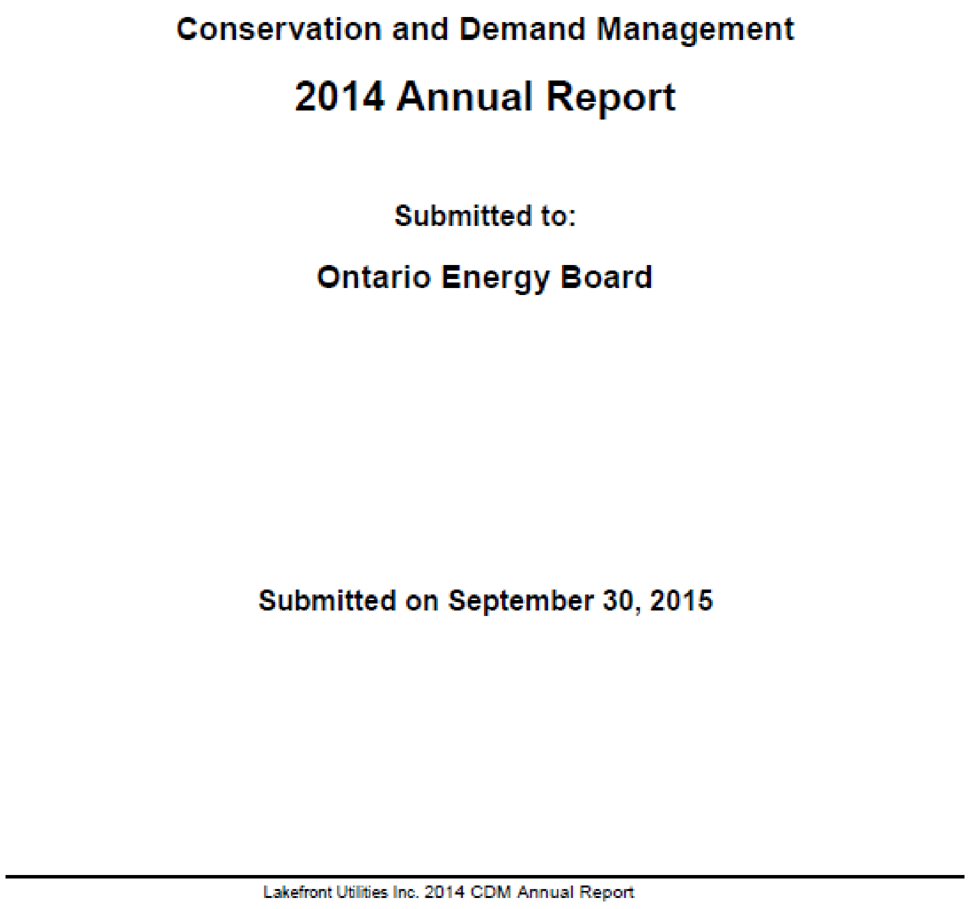
	2011 Original Strategy Projection		Actual 2011 Results		2012 Revised Strategy Projection		Actual 2012 Results		2013 Revised Strategy Projection		Actual 2013 Results		2014 Revised Strategy Projection		Actual 2014 Results		Revised Total Projected Reduction		Contribution to Target	
Percentage of Target	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh
	15.3%	**40.6%**	**18.3%**	**34.3%**	**15.5%**	**26.9%**	**10.6%**	**40.2%**	**21.0%**	**24.2%**	**14.5%**	**18.8%**	**24.8%**	**17.3%**	**17.7%**	**17.4%**	**64%**	**91.9%**	**61.1%**	**110.7%**

Note: Total Projection is formed of 2011, 2012 & 2013 Actuals added with 2014 Revised Strategy Projection

6.0 Addendums:

Lakefront Utilities Inc.

Addendum 4 – CHEC CDM Combined Annual Report 2014



Conservation and Demand Management

2014 Annual Report

Submitted to:

Ontario Energy Board

Submitted on September 30, 2015

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Executive Summary

This annual report is submitted by Lakefront Utilities Inc. (LUI) in accordance with the filing requirements set out in the Conservation and Demand Management ("CDM") Code for Electricity Distributors, issued September 16, 2010, Board File No. EB-2010-0215 specifically, the Appendix C Annual Report Template, as a progress report and update to LUI's Strategy filed with the Ontario Energy Board ("Board" or "OEB") on November 1, 2010. Accordingly, this report outlines LUI's CDM activities for the period of January 1, 2014 to December 31, 2014. It includes net peak demand and net energy savings achieved in 2011, 2012, 2013, and 2014, CDM program activities, successes and challenges.

LUI did not apply for any Board-approved CDM programs during 2014 however, as noted in the Guidelines for Electricity Distributors Conservation and Demand Management ("CDM Guidelines"), released April 26, 2012, the Board has deemed Time-of-Use ("TOU") pricing to be a province-wide Board-approved CDM program. The Ontario Power Authority ("OPA"), now Independent Electricity System Operator ("IESO"), is to provide measurement and verification on TOU. The TOU savings allocated to LUI's 2011 -2014 targets are 114kW.

In 2011 – 2014, LUI contracted with the IESO to deliver a portfolio of IESO-contracted province-wide CDM programs ("IESO Programs") to all customer segments including residential, commercial, institutional, industrial and low income. Most of these programs were rolled-out by the IESO in June 2011. In 2011, program activities were centered on building a foundation for full program execution over the next three years of the program term, including staffing, procurement, and program delivery.

In 2011, the Provincial Programs represented a partial year for market delivery. The challenges faced in finalizing the Master Agreements and schedules delayed the launch of the programs by several months. Once the schedules were released, reviewed and the contract was entered into, the LDC was tasked with determining the delivery mechanisms. LUI placed emphasis on the implementation of initiatives that would offer the greatest amount of persisting savings.

In 2012, Lakefront Utilities Inc. continued to place significant emphasis on the programs in market. The delivery of ERII and Direct Install programs continued to be active and the Home Assistance Program was launched and the Peak Saver RFP released. Lakefront Utilities Inc. launched all available OPA Programs following their release by the OPA, marketed the programs in all sectors, informed industry stakeholders about OPA Programs and used the online application system. The LDC also partnered with CHEC LDCs to form partnerships and delivery models for the various programs and engaged the services of a Roving Energy Manager in conjunction with other CHEC LDCs. LUI actively participated in EDA, LDC and OPA working groups through LUI staff or CHEC resources in order to improve and simplify the existing programs and processes, and transitioned pre-2011 projects into 2011.

In 2013, Lakefront Utilities Inc. delivered all in market programs with the associated marketing and customer support. The commercial programs such as ERII and Small Business Lighting continued to have generally good traction in the market place and demonstrated industry recognition. While the Peak Saver RFP had been released towards the end of 2012, the award of the contract, technology selection and system preparedness issues resulted in limited market exposure in 2013. During this period the Roving Energy Manager's contract was renewed to continue this important collaborative resource for CHEC LDCs. The residential programs continue to struggle to produce significant gains within this sector when compared to the industrial & commercial programs.

In 2014, LUI continued to deliver all in-market programs with the associated marketing and customer support. The commercial programs, specifically the Retrofit program continued to have good market awareness and uptake over the

2

year. The Roving Energy Manager position was continued as part of the CHEC collaborative effort and assisted in maintaining focus and performance in this sector. Peak Saver was in market however continued to generally struggle. The customer engagement in this program did not meet expectations along with the associated demand reduction.

LUI achieved 0.6 MW of net incremental peak demand savings and 1.2 GWh of net incremental energy savings in 2014. A summary of the achievements towards the CDM targets is shown below:

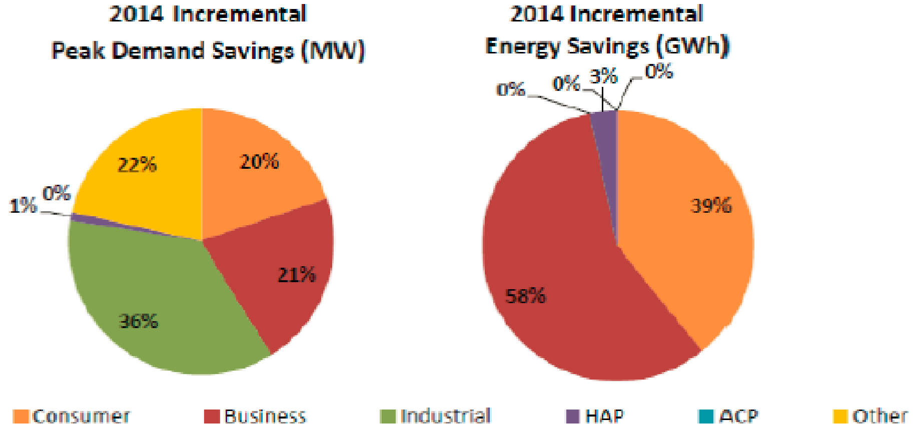
IESO-Contracted Province-Wide CDM Programs: 2011-2014 Final Results Report

LDC: Lakefront Utilities Inc.

Final 2014 Achievement Against Targets	2014 Incremental	2011-2014 Achievement Against Target	% of Target Achieved
Net Annual Peak Demand Savings (MW)	0.6	1.1	40.2%
Net Energy Savings (GWh)	1.2	10.4	76.9%

Unless otherwise noted, results are presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Achievement by Sector


2014 Incremental Peak Demand Savings (MW)

2014 Incremental Energy Savings (GWh)

From the above table, LUI has achieved 1.1 MW or 40.2% and 10.4 GWh or 76.9 % towards LUI's 2014 peak demand reduction target and energy consumption reduction targets respectively. The shortfall of peak demand targets were mainly due to late start of programs, cancellation of planned province wide programs including Direct Space Cooling since 2011 and low uptake of residential and small commercial demand response programs. The suite of programs, while supporting kW savings did not see significant demand focused projects implemented at the customer level. While many projects resulted in significant kWh the demand was minimal. The shortfall of energy targets was mainly due to the lost opportunity in the first year which had a cumulative effect on the target and a limited number of program offerings, as noted previously. While interest in the commercial sector remained strong the long planning and implementation cycle for many of the commercial and industrial customers resulted in project implementation dates beyond December 31, 2014. These projects and resulting savings will carry forward into the Conservation First Framework.

In 2015, the Conservation First Framework (CFF) for the period 2015 -2020 will be implemented. LUI submitted a CDM Plan for the Conservation First Framework to the IESO in April 2015. To ensure a smooth transition between the frameworks, most 2011- 2014 Programs and Rules were extended into 2015 until the effective implementation start date of January 1, 2016 under the Conservation First Framework.

Background

On March 31, 2010, the Minister of Energy and Infrastructure of Ontario, under the guidance of sections 27.1 and 27.2 of the *Ontario Energy Board Act, 1998*, directed the OEB to establish Conservation and Demand Management ("CDM") targets to be met by electricity distributors. Accordingly, on November 12, 2010, the OEB amended the distribution license of LDC to require LDC, as a condition of its license, to achieve 13.59 GWh of energy savings and 2.77 MW of summer peak demand savings, over the period beginning January 1, 2011 through December 31, 2014.

In accordance with the same Minister's directive, the OEB issued the Conservation and Demand Management Code for Electricity Distributors (the "Code") on September 16, 2010. The Code sets out the obligations and requirements with which electricity distributors must comply in relation to the CDM targets set out in their licenses. To comply with the Code requirements, LUI submitted its CDM Strategy on November 1, 2010 which provided a high level of description of how LUI intended to achieve its CDM targets.

The Code also requires a distributor to file annual reports with the Board. This is the fourth Annual Report by LUI and has been prepared in accordance with the Code requirements and covers the period from January 1, 2014 to December 31, 2014.

LUI submitted its 2011 Annual Report on September 28, 2012 which summarized the CDM activities, successes and challenges experienced by LUI for the January 1, 2011 to December 31, 2011 period. The OEB's 2011 CDM Results Report identified that the delay in the full suite of CDM programs being made available by the IESO, and the absence of some programs negatively impacted the final 2011 results for the LDCs. This issue was also highlighted in Volumes I and II of the Environmental Commissioner's Report on Ontario's Annual Energy Conservation Progress.

On December 21, 2012, the Minister of Energy directed the IESO to fund CDM programs which meet the definition and criteria for IESO-contracted province-wide CDM programs for an additional one-year period from January 1, 2015 to December 31, 2015.

The Ministerial Directive did not amend the timelines for LDCs to achieve their energy savings and demand savings targets. Therefore, the main focus of the LDCs remains the achievement of CDM targets by December 31, 2014.

LUI submitted its 2013 Annual Report on September 30, 2014 which summarized the CDM activities undertaken by LUI for the January 1, 2013 to December 31, 2013 period. The OEB's 2013 CDM Results report identified that the majority of LDCs achieved close to 50% of their net peak demand (MW) target from their 2013 results. LUI achieved 29.2% of their demand target in 2013 due largely to technology delays from the meter manufacturer. In general, LDCs advised the Board that meeting their peak demand (MW) target is not likely and that a shortfall is expected.

In 2014, LDCs collectively achieved approximately 19.5% of the energy savings (GWh) target, adding to the overall cumulative result of approximately 109% of the net energy target of 6,000 GWh.

1. Conservation Framework

1.1 2011-2014 Framework

Ontario's current CDM framework is a key step towards creating a culture of conservation in the Province. The Ontario Government ("Government") Directive to the OEB to establish CDM targets that would be met by electricity distributors recognizes the importance of CDM for both electricity customers and the electricity system. CDM helps customers manage rising energy costs, supports the provincial integrated supply plan, and addresses local distribution and transmission supply constraints. The past framework was intended to enable customers to benefit from a suite of both Board-approved and IESO province-wide programs and provide a portfolio that would meet both broad and specific customer needs.

The state of Board-approved programs and the current suite of province-wide IESO programs have limited CDM offerings to customers. This has produced limited savings and has restricted the associated opportunity for LDCs to meet their targets. The process to introduce changes to current program initiatives or to pilot new initiatives has been challenging, involving considerable cost and effort, which has resulted in limited benefits to customers and CDM savings.

Challenges faced by LDCs in the 2011-2014 framework, such as overbuilt governance and unnecessarily excessive legal requirements and misalignment of control and risks, have been addressed by the new directive. However, there are still many challenges to overcome and the new CDM framework should address other challenges of the current framework and build on its strengths.

1.2 Conservation First Framework

LDCs are supportive of the Government's renewed commitment for CDM in Ontario. LDCs are committed to working with the Government, IESO, Natural Gas Utilities and other stakeholders to develop programs for the new framework for CDM in the Province.

Long-term commitment for CDM funding and confirmation of the role of LDCs have been provided in the Minister's directive dated March 31, 2014, allowing LDCs to maintain current program infrastructure, including LDC staff and third party contracts as required.

The commitment also provided LDCs the program extensions required for continuity into the Conservation First Framework which was critical for all customers.

2. Board-Approved CDM Programs

2.1. Introduction

In its Decision and Order dated November 12, 2010 in EB-2010-0215 and EB-2010-0216, the OEB ordered that, to meet its mandatory CDM targets, "Each licensed electricity distributor must, as a condition of its licence, deliver Board-approved CDM programs, IESO-contracted province-wide CDM programs, or a combination of the two".

At this time, the implementation of TOU pricing is the only Board-approved CDM program that is being offered at LUI.

2.2 TOU Pricing

2.2.1Background

In its April 26, 2012 CDM Guidelines, the OEB recognizes that a portion of the aggregate electricity demand target was intended to be attributable to savings achieved through the implementation of TOU pricing. The OEB establishes TOU prices and has made the implementation of this pricing mechanism mandatory for distributors. On this basis, the OEB has determined that distributors will not have to file a Board-approved CDM program application regarding TOU pricing. The OEB has deemed the implementation of TOU pricing to be a Board-approved CDM program for the purposes of achieving the CDM targets. The costs associated with the implementation of TOU pricing are recoverable through distribution rates, and not through the Global Adjustment Mechanism ("GAM").

In accordance with the Ministry directive dated March 31, 2010 by the Minister of Energy and Infrastructure, the OEB is of the view that any evaluation of savings from TOU pricing should be conducted by the IESO for the Province, and then allocated to distributors. LUI has included the results provided by the IESO in this report.

In 2013, IESO had retained the Brattle Group as the evaluation contractor and has been working with an expert panel convened to provide advice on methodology, data collection, models, savings allocation, etc. The initial evaluations were conducted in 2013 with five LDCs – Hydro One Networks Inc., Toronto Hydro-Electric System Limited, Hydro Ottawa Limited, Thunder Bay Hydro Electricity Distribution Inc. and Newmarket-Tay Power Distribution Ltd. Preliminary results from these five LDCs were issued to the five LDCs involved in the study in August 2013 and are now publically available on the IESO website. Preliminary results demonstrated load shifting behaviours from the residential customer class.

Three additional LDCs were added to the study in 2014 – Cambridge-North Dumphries, PowerStream and Sudbury. Preliminary results from this study are planned to be issued to the eight LDCs in September 2014. The IESO advised that the TOU study will be completed in the summer of 2015 and final verified savings will be available for LDCs to include in the 2014 Annual Report.

The TOU savings as reported by the IESO is included in this report and accounts for 114 kW which represents 4.12% of the LUI demand target.

2.2.2 TOU PROGRAM DESCRIPTION

Target Customer Type(s): Residential and small business customers (up to 250,000 kWh per year)

Initiative Frequency: Year-round

Objectives: TOU pricing is designed to incent the shifting of energy usage. Therefore peak demand reductions are expected, and energy conservation benefits may also be realized.

Description: In August of 2010, the OEB issued a final determination to mandate TOU pricing for Regulated Price Plan ("RPP") customers by June 2011, in order to support the Government's expectation for 3.6 million RPP consumers to be on TOU pricing by June 2011, and to ensure that smart meters funded at ratepayer expense are being used for their intended purpose.

The RPP TOU price is adjusted twice annually by the OEB. A summary of the RPP TOU pricing is provided.

Table 1: RPP TOU Pricing Summary

	Prices (cents/kWh)		
Effective Date	**On Peak**	**Mid Peak**	**Off Peak**
November 1, 2010	9.9	8.1	5.1
May 1, 2011	10.7	8.9	5.9
November 1, 2011	10.8	9.2	6.2
May 1, 2012	11.7	10.0	6.5
November 1, 2012	11.8	9.9	6.3
May 1, 2013	12.4	10.4	6.7
November 1, 2013	12.9	10.9	7.2
May 1, 2014	13.5	11.2	7.5
November 1, 2014	14.0	11.4	7.7

Delivery: The OEB sets the TOU prices; LDCs install and maintain the smart meters; LDCs convert customers to TOU billing.

1.4.3 TOU Initiative Activities/Progress

LUI began transitioning its RPP customers to TOU billing on May 1, 2010. At December 31st, 2014, 100% of LUI's RPP customers were on TOU billing.

2.3 LUI's Application with the OEB

LUI did not submit a CDM program application to the OEB in 2014.

2.4 LUI's Application with the IESO's Conservation Fund

In 2013, the IESO introduced the Conservation Fund's Program Innovation stream to help meet LUI's interest in the development and launch of new local, regional and province-wide initiatives. The Conservation Fund's LDC Program Innovation stream fast-tracks LDC-led program design and the launch of successfully piloted initiatives prior to full scale deployment. By driving program innovation through the Conservation Fund, LDCs have the opportunity to both realize additional savings through the piloting and implementation of initiatives not currently addressed by the IESO portfolio and the means to test concepts for future local or province wide programs post 2014. As per the IESO, as of March 2014, three pilots have been contracted and are underway with Toronto Hydro and Niagara Peninsula Energy and ten others are in various stages of the contracting and development process.

In addition, building on LDC interest in social benchmarking services for the residential sector, in 2013 the Conservation Fund in collaboration with Hydro One, Milton Hydro and Horizon Utilities completed the procurement of three social benchmarking pilot projects. Beginning in 2014 these services will be offered to more than 100,000 customers for a one year period, with evaluation reports published shortly thereafter.

LUI did not submit a CDM program application to the IESO's Conservation Fund in 2014.

3 IESO-Contracted Province-Wide CDM Programs

3.1 Introduction

Effective March 11, 2011 LUI entered into an agreement with the IESO to deliver CDM programs extending from January 1, 2011 to December 31, 2014. The programs included under this agreement are listed in Table 2 below. Further program details are included in Appendix A. In addition, results include projects started pre 2011 which were completed in or after 2011:

Table 2: IESO-Contracted Province-Wide CDM Program Initiatives

Initiative	Schedule	Date schedule posted	Lakefront in Market Date
Residential Programs			
Appliance Retirement	Schedule B-1, Exhibit D	*Jan 26,2011*	*March 11, 2011*
Appliance Exchange	Schedule B-1, Exhibit E	*Jan 26, 2011*	*March 11, 2011*
HVAC Incentives	Schedule B-1, Exhibit B	*Jan 26, 2011*	*March 11, 2011*
Conservation Instant Coupon Booklet	Schedule B-1, Exhibit A	*Jan 26, 2011*	*March 11, 2011*
Bi-Annual Retailer Event	Schedule B-1, Exhibit C	*Jan 26, 2011*	*March 11, 2011*
Retailer Co-op	n/a	*n/a*	
Residential Demand Response	Schedule B-3	*Aug 22, 2011*	*May 15, 2014*
New Construction Program	Schedule B-2	*Jan 26, 2011*	*June 2011*
Home Assistance Program	Schedule E-1	*May 9, 2011*	*January 1, 2012*
Commercial & Institutional Programs			
Efficiency: Equipment Replacement	Schedule C-2	*Jan 26, 2011*	*May 1, 2011*
Direct Install Lighting • *General Service <50 kW*	Schedule C-3	*Jan 26, 2011*	*May 18, 2011*
Existing Building Commissioning Incentive	Schedule C-6	*Feb 2011*	*November 2011*
New Construction and Major Renovation Initiative	Schedule C-4	*Feb 2011*	*July 2011*
Energy Audit	Schedule C-1	*Jan 26, 2011*	*September 2011*
Commercial Demand Response • *General Service <50 kW*	Schedule B-3	*Jan 26, 2011*	*May 15, 2014*
Industrial Programs - General Service 50 kW & above			
Process & System Upgrades	Schedule D-1	*May 31, 2011*	*November 1, 2011*
Monitoring & Targeting	Schedule D-2	*May 31, 2011*	*September 1, 2011*
Energy Manager	Schedule D-3	*May 31, 2011*	*January 23, 2012*
Key Account Manager ("KAM")	Schedule D-4	*May 31,2011*	*n/a*
Demand Response 3	Schedule D-6	*May 31, 2011*	*January 2011*

In addition, results were realized towards LUI's 2011-2014 targets through the following pre-2011 programs:

- Electricity Retrofit Incentive Program

As per the table below, several program initiatives are no longer available to customers or have not been launched.

Table 3: Pre-2011 IESO Programs

Not in Market	Objective	Status
Residential Program		
Midstream Electronics	Encourages retailers to promote and sell high efficency televisions, and for distributors to distribute high efficiency set top boxes.	Did not launch and removed from Schedule in Q2, 2013.
Midstream Pool Equipment	Encourage pool installers to sell and install efficient pool pump equipment in residential in-ground pools.	Did not launch and removed from Schedule in Q2, 2013.
Home Energy Audit Tool	This is a provincial online audit tool to engage customers in conservation and help drive customer participation to CDM programs.	Did not launch and removed from Schedule in Q2, 2013.
Commercial & Institutional Program		
Direct Service Space Cooling	Offers free servicing of air conditioning systems and refrigeration units for the purpose of achieving energy savings and demand reduction.	Did not launch.
Demand Response 1 ("DR1")	This initiative allows distribution customers to voluntarily reduce electricity demand during certain periods of the year pursuant to the DR 1 contract. The initiative provides DR payment for service for the actual electricity reduction provided during a demand response event.	No customer uptake for this initiative. As a result this Initiative was removed from the Schedule in Q4, 2012.
Industrial Program		
DR1	As above	No customer uptake for this initiative. Removed in Q4, 2012.

The Master CDM Program Agreement between LDC and the IESO includes a program change management provision in Article 3. Collaboration between the IESO and LDC commenced in 2011, and continued in 2012, 2013 and 2014, as the change management process was implemented to enhance the saveONenergy program suite. The change management process allows for modifications to the Master CDM Program Agreement and initiative Schedules. The program enhancements give LDCs additional tools and greater flexibility to deliver programs in a way that meets the needs of customers and further drives participation in the Initiatives.

3.2 Program Descriptions

Full descriptions of IESO-contracted province-wide CDM programs are available on the IESO's intranet LDC and additional initiative information can be found on the saveONenergy website at https://saveonenergy.ca. The targeted customer types, objectives, and individual descriptions for each program initiative are detailed in Appendix A. Discussion of LDC's experience with these programs is provided below.

3.2.1 RESIDENTIAL PROGRAM

Description: Provides residential customers with programs and tools to help them understand and manage the amount of energy they use in their home and help the environment.

Objective: To provide incentives to both existing homeowners and developers/builders to motivate the installation of energy efficiency measures in both existing and new home construction.

Discussion:

The addition of Light Emitting Diode ("LED") technology into the bi-annual retailer events in 2012 and the annual coupons in 2013, as well as LDC custom coded coupons, has had a positive effect on consumer engagement and provided LDC with opportunities to achieve additional savings in their service territory. The Residential Demand Response program is one of the main residential initiatives which has the highest potential to drives savings for LDCs. It was anticipated that the in-Home Display ("IHD") would assist customers to manage their energy consumption and result in savings towards the kWh target. Unfortunately, there were no savings associated with the Energy Display attributed to LDCs in the IESO's final verified results as included in this report. The Heating and Cooling incentives program continues to be one of the strongest performer in the residential suite of programs with 2014 having LUI's highest participation. This program is mainly driven by contractors participating in the program but they may not always deliver results in the required manner (e.g. allowing customers to apply for their own incentives and tardy reporting).

The Residential Program Portfolio is predominately a carryover of initiatives from previous programs. Three new initiatives were never launched and subsequently removed from the schedule in 2013 with no new additions. Delays in communication with regards to initiative offerings and results reporting have hampered LDCs' abilities to engage customers and promote participation. Province-wide advertising has provided value in all residential programs except for *peaksaver* **PLUS**® due to technological inconsistency across LDCs.

Work to revitalize and increase the effectiveness and breadth of the initiatives through the residential program needs to be a high priority. There are opportunities within the residential marketplace that need to be addressed, program developed and offered to customers. The Version 5 schedules changes under the Master Agreement implemented in Q1/Q2 2014 have increased the number of LDC-coded coupons available and made new installations of central heating and cooling systems eligible for the Heating and Cooling Incentive.

3.2.1.1 Appliance Retirement Initiative (Exhibit D)

Initiative Activities/Progress: In 2014 the Appliance Retirement initiative continued to be promoted online, through the IVR phone system, at local events, through fridge magnets and in front office displays.

Although the previous two years had seen a decline in participation, 2014 saw an increase of 39.5% from 2013.

Additional Comments:

- Due to the duration of the program, and the revised appliance eligibility requirements to a minimum age of 20 years old, this initiative appears to have reached market saturation and has been under consideration for removal from the portfolio.
- IESO results are very responsive to province-wide advertising. IESO provincial marketing should continue to play a key role.
- Better relationships with retailers may play a role in increasing participation in this initiative. Retailers can provide opportunities to capture replacement appliances and have them decommissioned after a sale has been committed.
- In an effort to capture additional savings in the perceived last year of the initiative, the eligibility requirement for refrigerators was revised from 20 years old to 15 years old in Q2 2014, prior to the conclusion of this program by December 31, 2014.
- Due to the announcement by the IESO that the Appliance Retirement program was going to cease at the end of 2014, many LDCs lowered (or removed) their marketing support for the program.

3.2.1.2 Appliance Exchange Initiative (Exhibit E)

Initiative Activities/Progress: Marketing for this program was done in conjunction with the other residential programs and promoted on the website.

Additional Comments:

- The design of the initiatives, including eligible measures and incentives amounts are developed through the Residential Working Group. Retail partner(s) are contracted by the IESO to deliver the initiatives province-wide. Individual LDCs have the opportunity to stage in-store events to drive the distribution of LDC coded coupons and promotion of other programs in the portfolio
- This initiative, eligible measures and incentive amounts are influenced by the retail partner with very limited involvement from the LDCs. The restrictive, limited and sometimes non-participation of local stores can diminish the savings potential for this initiative.
- To date there has only been one retailer participant in the Appliance Exchange Initiative.
- Evaluation, Measurement, and Verification ("EM&V") results indicated that the value of savings for retired room air conditioners ("AC") has dropped resulting in the retail participant not accepting window ACs during the Spring 2013 event.
- Notification to LDCs regarding retailer participation and eligible measures continues to be delayed. Improved communications will aid in appropriate resource allocation and marketing of the initiative.

- This initiative may benefit from the disengagement of the retailer and allowing LDCs to conduct these events, possibly as part of a larger community engagement effort, with the backing of the IESO's contractor for appliance removal.
- The initiative appears to require more promotion from retailers and LDCs.

3.2.1.3 HVAC Incentives Initiative (Exhibit B)

Initiative Activities/Progress: Local promotion for this program was combined with other residential programs, information was displayed in the front office, on the website and promoted through qualified contractors.

Additional Comments:

- Incentive levels appear to be insufficient to prompt participants to upgrade HVAC equipment prior to end of useful life. An Air Miles incentive was introduced in 2013 to try and encourage early replacement.
- This initiative is contractor driven with LDCs responsible for marketing efforts to customers. More engagement with the HVAC contractor channel should be undertaken to drive a higher proportion of furnace and central air conditioner sales to eligible units.
- There are cases where non-participating contractors are offering their own incentives (by discounting their installations to match the value of the IESO incentive) to make the sale. As this occurs outside of the initiative, savings are not credited to LDCs. IESO should consider this in future program impact evaluation studies.
- Changes to the schedules in 2014 to allow for incentives for new installations, rather than strictly replacement units, may prove to be effective in providing greater results, increasing provincial participation by 20% over 2013.

3.2.1.4 Conservation Instant Coupon Initiative (Exhibit A)

Initiative Activities/Progress: The IESO actively promoted the coupons with point of sale advertising. LUI distributed coupons locally at the front office and at community events, as well as promoted the coupons and through the website.

Additional Comments:

- The timeframe for retailer submission of redeemed coupons vary from retailer to retailer, and in some cases has been lengthy. The delays and incomplete results reporting limits the ability to react and respond to initiative performance or changes in consumer behaviour.
- The product list could be distinctive from the Bi-Annual Retailer Event Initiative in order to gain more consumer interest and uptake.
- Program evolution, including new products and review of incentive pricing for the coupon initiatives, should be a regular activity to ensure continued consumer interest.

- All coupons have been provided with LDC custom coding in 2014 which allows LDCs to promote coupons based on local preferences. However, LDCs were not provided with customer coded coupon results until early 2015 and thus, had no indication of their redemption rates.
- Consumer experience varies amongst retailers offering coupon discounts which can limit redemptions. For example, a particular high volume 'participating retailer' does not accept coupons and has their own procedure. In addition, some retailers have static lists of eligible products and will not discount eligible products unless the product is on the list.
- The saveONenergy programs would benefit from specific end cap displays, aisle product stands and product-specific areas. Having products throughout a retail environment weakens the impact.

3.2.1.5 Bi-Annual Retailer Event Initiative (Exhibit C)

Initiative Activities/Progress: The IESO actively promoted the coupons with point of sale advertising. LUI distributed the IESO provided coupons to customers at the front office and at local community events. LUI also promoted the coupons on the radio and website. LUI monitored retailers to ensure that in store coupons were available throughout the two events.

Additional Comments:

- This initiative is strongly influenced by the retail participants and has no direct involvement from the LDCs.
- LDCs have the opportunity to stage in-store events to drive the distribution of LDC-coded coupons and promotion of other programs in the portfolio; however, this requires cooperation from the local retailer and LDC staff resources.
- The product list has had minimal changes over the past four years.
- Limited engagement of local retailers can restrict the savings potential for this initiative.
- Program evolution, including new products and review of incentive pricing for the coupon initiatives, must be a regular activity to ensure continued consumer interest.
- The product list could be distinctive from the Conservation Instant Coupon Initiative in order to gain more consumer interest and uptake.
- A review conducted by the EDA Residential Working Group in 2011 identified three areas of need for initiative evolution: 1) introduction of product focused marketing; 2) enhanced product selection; and 3) improved training for retailers as retail staffs tend not to be knowledgeable regarding the products or promotion.
- This initiative may benefit from a more exclusive relationship with a retailer appropriate to the program. There should be a value proposition for both the retailer and LDC.
- Independently, the Retailer Co-op and Bi-Annual Retailer Event Initiative may not present a value for the investment of LDC resources to support these events and should be backed by a strong residential portfolio.

3.2.1.6 Retailer Co-op

Initiative Activities/Progress: Due to limited staffing resources LUI did not actively pursue this initiative.

Additional Comments:

- This is a retailer initiative with no direct benefit to LDCs
- Limited engagement of local retailers can restrict the savings potential for this initiative.
- The availability of retailer and/or LDC staff with product knowledge and the ability to conduct demonstration in store during the events would be an asset. This could be a valuable role for LDCs, however many LDCs are limited by available resources and unable to participate.

3.2.1.7 New Construction Program (Schedule B-2)

Initiative Activities/Progress: LUI's service territory has seen very little new construction which has limited this initiative. This program was promoted in combination with other saveONenergy initiatives online and through information sheets which were made available in the front office.

Additional Comments:

- This initiative provides incentives to home builders for incorporating energy efficiency into their buildings. To support this, LDCs need to provide education to consumers regarding the importance of choosing the energy efficient builder upgrade options without an immediate benefit to the consumer.
- In 2012 the application process was streamlined, however continues to be too cumbersome for builders. This, combined with limited return, has resulted in this initiative continuing to under-achieve.
- Administrative requirements, particularly with individual home modeling, must align with perceived stakeholder payback.
- The addition of LED light fixtures, application process improvement, and moving the incentive from the builder to the home-owner may increase participation.
- This initiative may benefit from collaboration with the natural gas utilities.

3.2.1.8 Residential Demand Response Program (Schedule B-3)

Initiative Activities/Progress: The RFP was released late in 2012 to engage providers and to finalize technology in order to commence the delivery of the program in 2013. It was anticipated that the initial year would allow any technology issues to be resolved and marketing of the program was also to begin in 2013, as well as initial installations. The need to postpone installations as colder weather approached to avoid completing the initial test installations when the AC would not be operating moved the in-market date later than anticipated. LUI was unable to launch the program to customers until June

2014 due to a required meter software upgrade. Once the initiative was launched, it was promoted through bill inserts, on-bill messages, through the website and direct mail pieces were sent to all previous peaksaver customers.

Additional Comments:

- Energy and demand savings have not been reported for the IHD portion of the program as 2013 EM&V results have determined zero savings associated with the IHD. IESO conducted another study in 2014, expanding its study territory beyond those included in the 2013 study to provincial rather than regional results. Results from the second study have not yet been announced. The demand savings associated with the control device has been included in this report.
- The variable funding associated with installing a load controllable thermostat is not sufficient unless it is combined with an IHD. This might not be possible at all times or when IHD is optional.
- Smart meters installed by most LDCs do not have the capability to communicate directly to an IHD and any mass replacement of newly installed meters with communicating abilities is not fiscally responsible. When proposing technical initiatives that rely on existing LDC infrastructure or technology there should be an extensive consultative process in order to prevent this type of problem in the future.
- Introduction of new technology requires incentives for the development of such technology. Appropriate lead times for LDC analysis and assessment, product procurement, and testing and integration into the smart meter environment are also required. Making seemingly minor changes to provincial technical specifications can create significant issues when all LDCs attempt to implement the solution in their individual environments.
- Given the different LDCs' smart meter environments and needs, each LDC is positioning the initiative with subtle differences. As such, greater program flexibility is required to address unique LDC needs

3.2.2 COMMERCIAL AND INSTITUTIONAL PROGRAM

Description: Provides commercial, institutional, agricultural and industrial organizations with energy-efficiency programs to help reduce their electrical costs while helping Ontario defer the need to build new generation and reduce its environmental footprint. Programs to help fund energy audits, replace energy-wasting equipment or pursue new construction that exceeds existing codes and standards. Businesses can also pursue incentives for controlling and reducing their electricity demand at specific times.

Targeted Customer Type(s): Commercial, institutional, agricultural, multi-family buildings, industrial.

Objective: Designed to assist building owners and operators as well as tenants and occupants in achieving demand and energy savings, and to facilitate a culture of conservation among these communities as well as the supply chains which serve them.

Discussion:

Throughout 2014 the Commercial and Institutional ("C&I") Working Group continued its efforts to enhance the existing C&I programs and rectify identified program and system deficiencies. This has proven to be a challenging undertaking, normally taking months to complete sometimes relatively minor changes due to the current CDM framework. Overbuilt governance, numerous initiative requirements, complex program structure and lengthy change management have restricted growth without providing the anticipated improved measurement and verification results. In addition, Evaluation, Measurement and Verification (EM&V) has not yet achieved transparency. LDCs are held accountable for these results yet are mostly completely removed from the process.

LDC program management has been hampered by varying rule interpretation, limited marketing ability, a somewhat inflexible online system of checks and balances and revolving IESO support personnel.

Despite these challenges the C&I Working Group, working in cooperation with the IESO, have managed to iron out many of the issues which could be rectified. In particular, an accomplishment of 2012 was the advent of the expedited change management as a mean to accelerate certain program changes. The benefits of expedited change management process were seen in 2013 and carried over into 2014.

Looking ahead there is an opportunity to make valuable changes to the current program suite for the Conservation First Framework, but LDCs and the IESO should look beyond the current initiatives and work to launch new programs, built on the strengths of the 2011-2014 programs, which will meet the needs of the industry and consumers.

The C & I portfolio does appear to be maintaining the traction within the industry with a number of companies and consultants making applications. The continued availability of the program is being incorporated into business cases within the sector.

Throughout 2014 Lakefront Utilities Inc. along with other CHEC LDCs benefited from the efforts of the Roving Energy Manager. The ability to collaboratively obtain this resource has been very beneficial.

3.2.2.1 Efficiency: Equipment Replacement Incentive ("ERII") (Schedule C-2)

Initiative Activities/Progress: The initiative continued to have good traction within the sector. Many of the projects were not fully implemented by December 31, 2014 and as such have transitioned into the new framework. Promotion of the program through various marketing initiatives has been on-going. These initiatives include direct mail to customers, online advertising and combined advertising with Commercial and Industrial Programs. The REM also visited our larger customers and LUI hosted a breakfast information session for local businesses to inform customers of the initiative.

Additional Comments:

- A large proportion of LDC savings are attributed to ERII.
- Capability building programs from industrial programs have had very positive contributions to ERII program.
- A number of customer-facing issues in iCon (the IESO's centralized application system) have been resolved; however, key LDC administrative back office processing issues continue to be a challenge. For example, currently LDCs are unable to record back office information to complete review and approval process using iCon.
- Applicants and applicant representatives continue to express dissatisfaction and difficulty with the online application system. This issue has been addressed by LDCs through application training workshops, channel partner/contractor training and LDC staff acting as customer application representatives. Although this has been an effective method of overcoming these issues and encouraging submissions, it also reflects on the complexity and time consuming nature of the application process. As such, applicant representatives continue to influence the majority of applications submitted. Continued development of channel partners is essential to program success.

- Lighting is still the most popular measure. Other market sectors are not as engaged yet, specifically the mechanical sector. There continues to be significant barriers to program participation from HVAC (Unitary AC) and compressed air channel partners
- Prescriptive and engineered worksheets provide a much needed simplified application process for customers. However, the eligible measures need to be updated and expanded in both technology and incentive amounts to address changing product costs and evolution of the marketplace.
- A focus on demand incentives has limited some energy project opportunities. In particular, night lighting projects have significant savings potential for customers but tend to have incentives of 10% or less of project cost.
- The requirement to have a customer invoice the LDC for their incentive is very burdensome for the customer and results in a negative customer experience and another barrier to participation.
- There is redundancy in the application process as customers may need to complete a worksheet and then enter most of that information over to the online application form. This can be cumbersome.
- Processing head office application became much easier for the lead LDC after schedule changes came into effect in August 2013. The changes implemented allowed the lead LDC to review and approve all facilities in a head office application on behalf of all satellite LDCs under certain circumstances.
- The application process for head office projects remains a significant barrier. Applicants need to manually enter one application per facility associated with the project which can be extremely onerous, often requiring a dedicated resource.
- Streamlining of the settlements systems resulted in significant improvement in the payment process in 2013.
- IESO implemented a cut-off date of July 31, 2014 for approval of 2014 social housing adder (SHA) under ERII program. IESO had instructed that any SHA applications that will be submitted to IESO after July 31, 2014 will not be honored for SHA, however, they failed to mention that it is the timeline to submit the funding request to the IESO by the LDCs and not the submission date of the applications to IESO's ICON system by the Applicant (Customer). As a result there were some confusions and some of the applications that were submitted to IESO's iCON by July 31, 2014 but LDCs submitted the funding request to IESO at a later date (once LDCs have completed review of the applications) were not honored for SHA. Additionally, the formal letter confirming that the SHA annual allocation has been exceeded was received by conservation officers on July 15, 2014 leaving them only 15 days to inform the customers and this created a negative customer experience.
- The handling of the exterior lighting incentives was a negative customer experience. In the fall of 2014 a new section was introduced in the prescriptive Lighting worksheet. It offered generous incentives for some exterior lighting projects and many municipal customers took advantage of the available incentives. Within 2 weeks of introducing the incentives, several incentives were suddenly removed for approximately 6 weeks until new incentives were created due to $/kWh incentive being too high for some of the measures. This caused a negative customer experience in several ways:
    - Some customers were planning on applying for rebates exterior prescriptive lighting measures based on the incentives offered but were suddenly not allowed to apply for prescriptive rebates.

  - The length of time from pulling out the exterior prescriptive lighting incentives to offering new incentives was too long. There should have been a temporary incentive level offered to allow LDCs to take in new applications.
  - The incentives should have been introduced at an appropriate level the first time. While market conditions can change, the incentives offered should have been researched and approved with the expectation that they would be in place for at least 6-12 months.
- Introduction of several new prescriptive measure worksheets including Plug Loads and Refrigeration were introduced in September 2014 allowed for new opportunities, albeit late in the framework.
- The Ministerial Directive provides continuity of the conservation programs for the participant, with clear direction on LDC administrative funding for 2015, which helps to avoid a gap in program delivery.

3.2.2.2 Direct Install Initiative ("DIL") (Schedule C-3)

Initiative Activities/Progress: Follow-up up with qualifying customers was initiated to drive participation and renew interest in the initiative. Local marketing collateral combined DIL with other commercial programs to maximize marketing efforts. Information was displayed in the front office, on the website and mailed directly to customers. Our third party consultants Burman Energy visited business customers frequently and performed a telemarketing campaign to drive participation.

Additional Comments:

- LED lighting was introduced in 2013 as a new measure and has been well received by customers who may not have previously qualified for DIL eligible upgrades. This is an efficient product with a long estimate useful life.
- Cold start high output lighting was removed from the program. This particularly affected the farming customers who now have limited options within the program.
- Successful execution of the previous version of this initiative has resulted in reduced potential for the 2011-2014 initiative in some LDC's territories.
- The inclusion of a standard incentive for additional measures increased project size and drove higher energy and demand savings results in some situations. However, LDCs are unable to offer these standard incentives to prior participants. The ability to return to prior participants and offer a standard incentive on the remaining measures has potential to provide additional energy and demand savings.
- Many customers are not taking advantage of any additional measures, which may present an opportunity for future savings with a new program offering.

3.2.2.3 Existing Building Commissioning Incentive Initiative (Schedule C-6)

Initiative Activities/Progress: General promotion of this initiative with similar programs was utilized. The opportunity for this initiative is limited in LUI service territory.

Additional Comments:

- Initiative name does not properly describe the initiative.
- There was minimal participation for this initiative. It is suspected that the lack of participation in the program is a result of the initiative being limited to space cooling and a limited window of opportunity (cooling season) for participation.
- Participation is mainly channel partner driven, however the particulars of the initiative have presented too much of a significant barrier for many channel partners to participate.
- The customer expectation is that the program be expanded to include a broader range of measures for a more holistic approach to building recommissioning and chilled water systems used for other purposes should be made eligible and considered through change management.
- This initiative should be reviewed for incentive alignment with ERII, as currently a participant will not receive an incentive if the overall payback is less than 2 years.

3.2.2.4 New Construction and Major Renovation Initiative ("HPNC") (Schedule C-4)

Initiative Activities/Progress: This program is dependent upon the type of development and renovations proposed in the service territory. Development is monitored to determine projects available for this program. There has only been one completed HPNC project in this framework.

Additional Comments

- With the Ministerial Directive issued December 21, 2012, facilities with a completion date near the end of 2014 with some confidence that they will be compensated for choosing efficiency measures.
- Participants had until the end of 2014 to submit their applications for the projects that will be completed in 2015. However savings achieved will be accounted for in the new framework (2015 - 2020).
- The custom application process requires considerable customer support and skilled LDC staff. The effort required to participate through the custom stream exceeds the value of the incentive for many customers.
- There are no custom measure options for items that do not qualify under the prescriptive or engineered track as the custom path does not allow for individual measures, only whole building modelling.
- The requirement to have a customer invoice the LDC for their incentive is very burdensome for the customer and results in a negative customer experience and a potential barrier to participation.

3.2.2.5 Energy Audit Initiative

Initiative Activities/Progress: The audit program has been promoted through site visits with the REM and a customer information session in June. In 2014 there were no applications received. It is realized the planning window may take some time for customers to implement. In the future framework more involvement from the REM may increase the number of audit applications received.

- The introduction of the new audit component for one system (i.e. compressed air), has increased customer participation.
- The energy audit Initiative is considered an 'enabling' initiative and 'feeds into' other saveONenergy initiatives.
- LDCs are receiving some savings towards their targets from an audit which is mainly attributable to operational savings.
- Audit reports from consultants vary considerably and in some cases, while they adhere to the initiative requirements, do not provide value for the participant. A standard template with specific energy saving calculation requirements should be considered.
- Customers look to the LDCs to recommend audit companies. A centralized prequalified list provided by the IESO may be beneficial.
- Participants are limited to one energy audit which restricts enabling and direction to the other initiatives. This has been revised in 2014 and LDCs are now able to consider additional customer participation when presented with a new scope of work.
- Consideration should be given to allowing a building owner to undertake an audit limited to their lighting system. This way they may receive valuable information from a neutral third party regarding the appropriate lighting solution for their facility instead of what a local supplier would like to sell.
- The requirement to have a customer invoice the LDC for their incentive is very burdensome for the customer and results in a negative customer experience and a potential barrier to participation

3.2.3 INDUSTRIAL PROGRAM

Description: Owners of large facilities are discovering the benefits of energy efficiency through the Industrial Programs which are designed to help identify and promote energy saving opportunities. It includes financial incentives and technical expertise to help organizations modernize systems for enhanced productivity and product quality, as well as provide a substantial boost to energy productivity. This allows facilities to take control of their energy so they can create long-term competitive energy advantages which reach across the organization.

Targeted Customer Type(s): Industrial, Commercial, Institutional, Agricultural

Objective:

- Offer distribution customers capital incentives and enabling initiatives to assist with the implementation of large projects and project portfolios;

- Implement system optimization projects in systems which are intrinsically complex and capital intensive; and
- Increase the capability of distribution customers to implement energy management and system optimization projects.

Discussion:

The Industrial Program Portfolio has been able to provide valuable resources to large facilities such as energy managers and enabling engineering studies. The engineering studies in particular provide a unique opportunity for a customer to complete a comprehensive analysis of an energy intensive process that they would not otherwise be able to undertake. Energy managers provide customers with a skilled individual whose only role is to assist them with conservation initiatives. To date these energy managers have played a key role in customer participation. The KAM and the industrial project supervisors have also been instrumental in managing the embedded energy managers ("EEM") during the first and second half of the year respectively, and promoting activity to the Class A customers.

Within the service territory of LUI there are a limited number of customers who can take advantage of the industrial portfolio of programs. In many instances the focus has been on the ERII program from the C&I Programs. The promotion of industrial programs has been assisted by the CHEC Roving Energy Manager, a position which has been filled from the 3rd quarter of 2012.

Due to the size, scope and long lead time of these initiatives and associated projects, the December 2012 Ministerial Directive provides some security for the continuation of the conservation programs and associated compensation for the participant; however the subsequent savings would not be attributed to an LDC's current target for projects that go into service after 2014.

Extensive legal documents, complex program structure and lengthy change management have restricted the change and growth of this portfolio. While the expedited change management has benefited the commercial portfolio, the industrial portfolio has not seen the same results due to the narrow scope of the process. For 2013 the change to the threshold for small capital projects and the new small capital project agreement improved the number of projects and savings achieved within Process and Systems Upgrades Initiation ("PSUI"). Likewise, a decision to proceed with applications for natural gas load displacement generation projects also increase uptake, although the limited time to bring new projects into service is a barrier.

3.2.3.1 Process and Systems Upgrades Initiative ("PSUI") (Schedule D-1)

Initiative Activities/Progress: LUI has received applications for PSUI, however none of the projects were completed before the framework deadline. PSUI is promoted by the Roving Energy Manager where appropriate. General promotion of this initiative along with similar programs was advertised in a general Commercial/Industrial brochure and on the website. There is limited opportunity in Lakefront's service territory.

Additional Comments:

- Numerous energy studies have been submitted and completed. This is a strong indication that there is potential for large projects with corresponding energy savings. Most of these studies have been initiated through Energy Manager and Key Account Manager ("KAM") resources.
- This initiative is limited by the state of the economy and the ability of a facility to complete large capital upgrades.

- There is typically a long sales cycle for these projects, and a long project development cycle. As such, limited results are expected to be generated in 2014. The majority of the results are expected in 2015 with a much reduced benefit to cumulative energy savings targets.
- Delays with processing funding payments have caused delayed payments to participants beyond contract requirements. In some cases, LDCs have developed a separate side agreement between the LDC and participant acknowledging that the participant cannot be paid until the funds are received.
- Given the size of the projects involved, the contract required for PSUI is a lengthy and complicated document. A key to making PSUI successful is the new agreement for 'small' projects with simplified and less onerous conditions for the customer.
- To partially address this, changes were made to the ERII program which allowed smaller projects to be directed to the commercial stream. Most industrial projects to-date has been submitted as ERII projects due to less onerous contract and M&V requirements. Therefore, PSUI engineering studies and LDC's industrial resources (e.g., Energy managers, KAMs) contribute significant savings to other programs such as ERII.
- A business case was submitted by the Industrial Working Group in July 2012 which changed the limit for a small project from 700 MWh to 1 million dollars in incentives. This would allow more projects to be eligible for the new small capital project agreement and increase participant uptake, while still protecting the ratepayer. This small capital project agreement was finalized through change management in September 2013.
- With the considerable customer interest in on-site load displacement (co-generation) projects, the initiative should be reviewed to ensure that these projects may be accepted as part of the PSUI Initiative. The IESO was reviewing waste heat projects only and all other co-generation projects were on hold prior to June 2013, when a decision was made to allow natural gas load displacement generation projects to proceed under PSUI. It is expected that a number of projects may proceed although results may not be counted towards LDC 2011-2014 framework target unless applications are submitted before the end of 2014 and the projects are in service before December 31, 2015.
- The requirement for customer invoice to the LDC and provide proof of payment to consultants for their incentive is very burdensome for the customer and results in a negative customer experience and another barrier to participation.

3.2.3.2 Monitoring and Targeting ("M&T") Initiative (Schedule D-2)

Initiative Activities/Progress: General promotion of this initiative along with similar programs was utilized, however there is limited opportunity in LUI's service territory. The hiring of a REM for CHEC LDCs assisted with this initiative. Monitoring and Targeting (M&T) is promoted by the Roving Energy Manager where appropriate.

Additional Comments:

- The M&T initiative is targeted at larger customers with the capacity to review the M&T data. This review requires the customer facility to employ an energy manager, or a person with equivalent qualifications, which has been a barrier for some customers. As such, only five applications has been completed in 2014, province wide.
- The savings target required for this initiative can present a significant challenge for smaller customers.

- Through the change management process in 2013, changes were made to ERII to allow smaller facilities to employ M&T systems.

3.2.3.3 Energy Manager Initiative (Schedule D-3)

Initiative Activities/Progress: The Roving Energy Manager has been actively engaging customers across the CHEC LDCs. Typically the LDC initiates a site visit to introduce the Roving Energy Manager to the company along with the offer of assistance. The Roving Energy Manager has been very successful across the LDCs and provides a significant contribution to the awareness of conservation options and to the evaluation and implementation of programs.

To support the efforts of the Roving Energy Manager, access to the OPA training and other programs has been made available to the REM. This assists in building capacity and will lead to continued good performance in future years.

Additional Comments:

- The Embedded Energy Managers ("EEMs") have proven to be a popular and useful resource for larger customers. There are approximately 50 EEMs and 22 Roving Energy Managers ("REMs") being utilized by customers across the province.
- LDCs that are too small to qualify for their own REM are teaming up with other utilities to hire a REM to be shared by the group of utilities.
- At the beginning, it took longer than expected to set up the energy manager application process and unclear communication resulted in marketing and implementation challenges for many LDCs.
- There have been a number of studies identified by energy managers and they have been able to build capacity and deliver energy savings projects within their respective large commercial/industrial facilities.
- The requirement that 30% of targets must come from non-incented projects is identified as an issue for most EEMs/REMs. The EDA Industrial Working Group has proposed to remove this requirement for REMs only as they are not resident full time at a customer facility to find the non-incented savings.

3.2.3.4 Key Account Manager (Schedule D-4)

Initiative Activities/Progress: LUI did not have the resources to participate in this initiative.

Additional Comments

- Not Applicable.

3.2.3.5 Demand Response 3 ("DR3") (D-6)

Initiative Activities/Progress: Marketing has been limited with DR3, however it has been promoted with other industrial programs in literature and on the website. The REM is including DR3 within discussions with customers and has received some interest. There has been limited activity in 2014.

Additional Comments:

- Until early 2013, customer data was not provided on an individual customer basis due to contractual requirements with the aggregators. This limited LDCs' ability to effectively market to prospective participants and confirm savings.
- The Industrial Working Group had a discussion with the IESO and representatives of the Ministry on proposed changes for the DR3 program. No program improvements were made in 2013. However, it was accepted that prior participants who renew their DR3 contract within the 2011-2014 term will contribute to LDC targets.
- As of 2013, aggregators are able to enter into contracts beyond 2014. This has allowed them to offer a more competitive contract price (five years) than the previously limited one- to two-year contracts. However on March 31, 2014 the Minister of Energy issued a directive entitled "Continuance of the IESO's Demand Response Program under IESO management" which restricts the IESO from granting any more contract schedules to aggregators, as the program is being transitioned from the OPA to the IESO. This decision will prevent the DR3 program from continuing to grow until the IESO is ready to assign DR3 capacity through a new auction process.
- Metering and settlement requirements are complicated and can reduce customer compensation amounts, and present a barrier to some customers.
- Compensation amounts have been reduced from the previous version of this program and subsequently there has been a corresponding decrease in renewal rates.

3.2.4 LOW INCOME INITIATIVE (HOME ASSISTANCE PROGRAM) (Schedule E-1)

Initiative Activities/Progress: The program has been in market for the entire year. 2013 saw record numbers for participation, unfortunately 2014 participation rates decreased by 74%. LUI has been promoting the Home Assistance Program throughout its service area through brochures at the Northumberland Help Centre, speaking with Property Managers at subsidized housing locations, and by engaging customers at community events. Green Saver, the third party contractor, actively promotes this initiative within the community.

Additional Comments:

- The process for enrolling in social housing was complicated and time consuming. This was addressed in late 2012 and showed benefits since 2013.
- The financial scope, complexity, and customer privacy requirements of this initiative are challenging for LDCs and most have contracted this program out. This initiative may benefit from an IESO contracted centralized delivery agent.

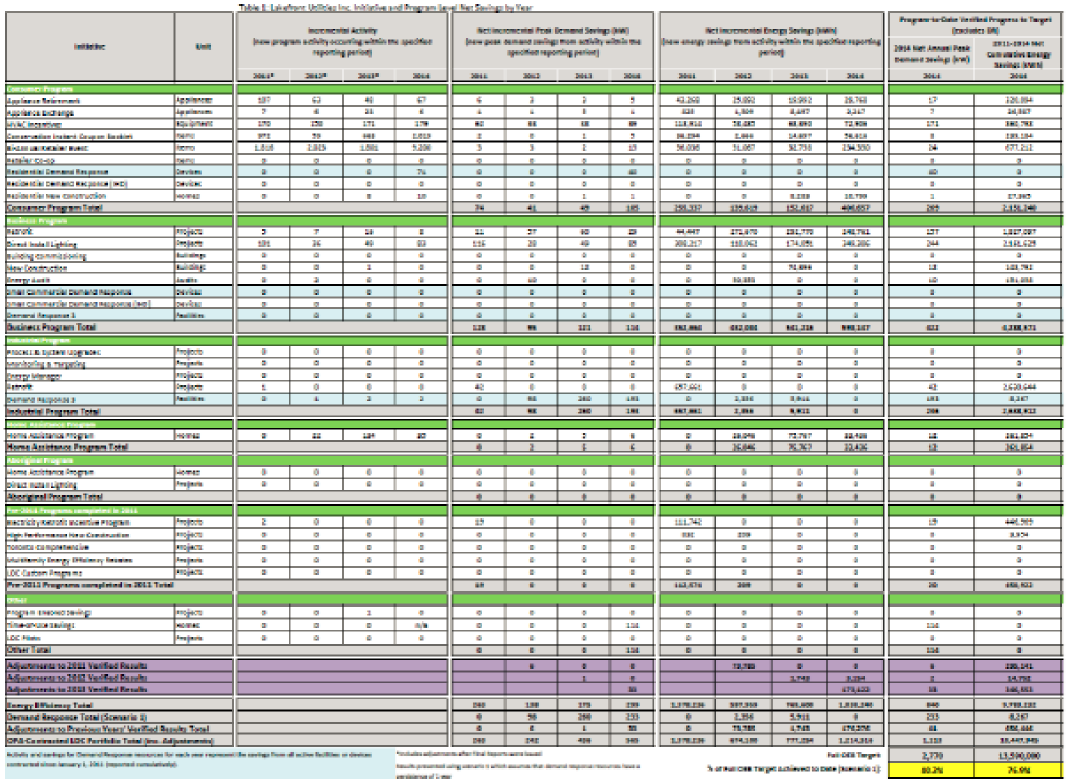
3.2.5 PRE-2011 PROGRAMS

Savings were realized towards LDC's 2011-2014 target through pre-2011 programs. The targeted customer types, objectives, descriptions, and activities of these programs are detailed in Appendix B

4 2014 Lakefront Utilities Inc. CDM Results

4.1 Participation and Savings

Table 1: Lakefront Utilities Inc. Initiative and Program Level Net Savings by Year



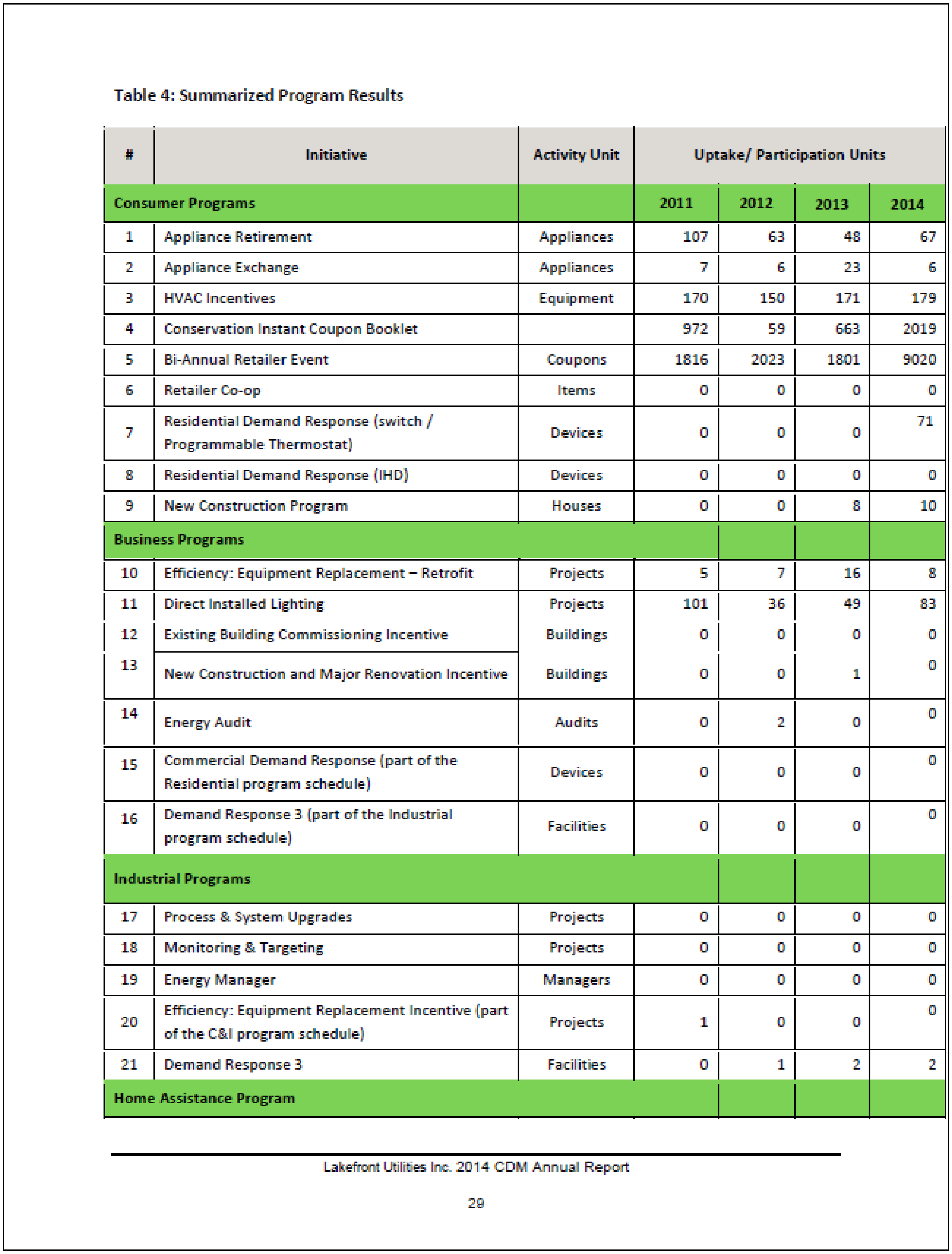
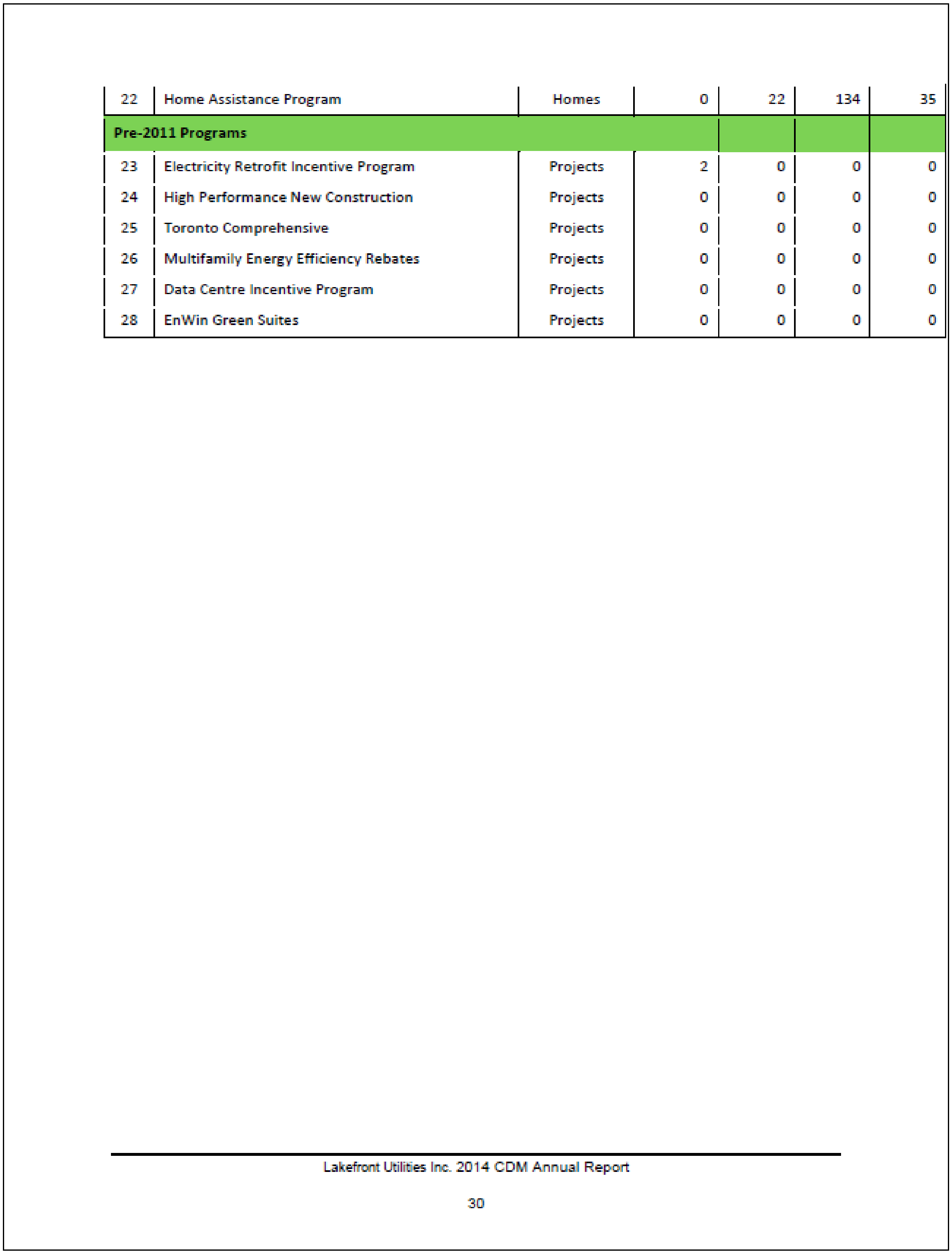


Table 4: Summarized Program Results

#	Initiative	Activity Unit	Uptake/ Participation Units			
Consumer Programs			**2011**	**2012**	**2013**	**2014**
1	Appliance Retirement	Appliances	107	63	48	67
2	Appliance Exchange	Appliances	7	6	23	6
3	HVAC Incentives	Equipment	170	150	171	179
4	Conservation Instant Coupon Booklet		972	59	663	2019
5	Bi-Annual Retailer Event	Coupons	1816	2023	1801	9020
6	Retailer Co-op	Items	0	0	0	0
7	Residential Demand Response (switch / Programmable Thermostat)	Devices	0	0	0	71
8	Residential Demand Response (IHD)	Devices	0	0	0	0
9	New Construction Program	Houses	0	0	8	10
Business Programs						
10	Efficiency: Equipment Replacement – Retrofit	Projects	5	7	16	8
11	Direct Installed Lighting	Projects	101	36	49	83
12	Existing Building Commissioning Incentive	Buildings	0	0	0	0
13	New Construction and Major Renovation Incentive	Buildings	0	0	1	0
14	Energy Audit	Audits	0	2	0	0
15	Commercial Demand Response (part of the Residential program schedule)	Devices	0	0	0	0
16	Demand Response 3 (part of the Industrial program schedule)	Facilities	0	0	0	0
Industrial Programs						
17	Process & System Upgrades	Projects	0	0	0	0
18	Monitoring & Targeting	Projects	0	0	0	0
19	Energy Manager	Managers	0	0	0	0
20	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Projects	1	0	0	0
21	Demand Response 3	Facilities	0	1	2	2
Home Assistance Program						



22	Home Assistance Program	Homes	0	22	134	35
Pre-2011 Programs						
23	Electricity Retrofit Incentive Program	Projects	2	0	0	0
24	High Performance New Construction	Projects	0	0	0	0
25	Toronto Comprehensive	Projects	0	0	0	0
26	Multifamily Energy Efficiency Rebates	Projects	0	0	0	0
27	Data Centre Incentive Program	Projects	0	0	0	0
28	EnWin Green Suites	Projects	0	0	0	0

Table 5: Verified Results

Table 5 has been removed from the standard report template as the net savings are illustrated in Participation and Savings chart above. Gross figures have not been presented as the measures towards target is the net savings. Standard E&V methods have been applied by the OPA to determine the net figures which are outlined in this report.

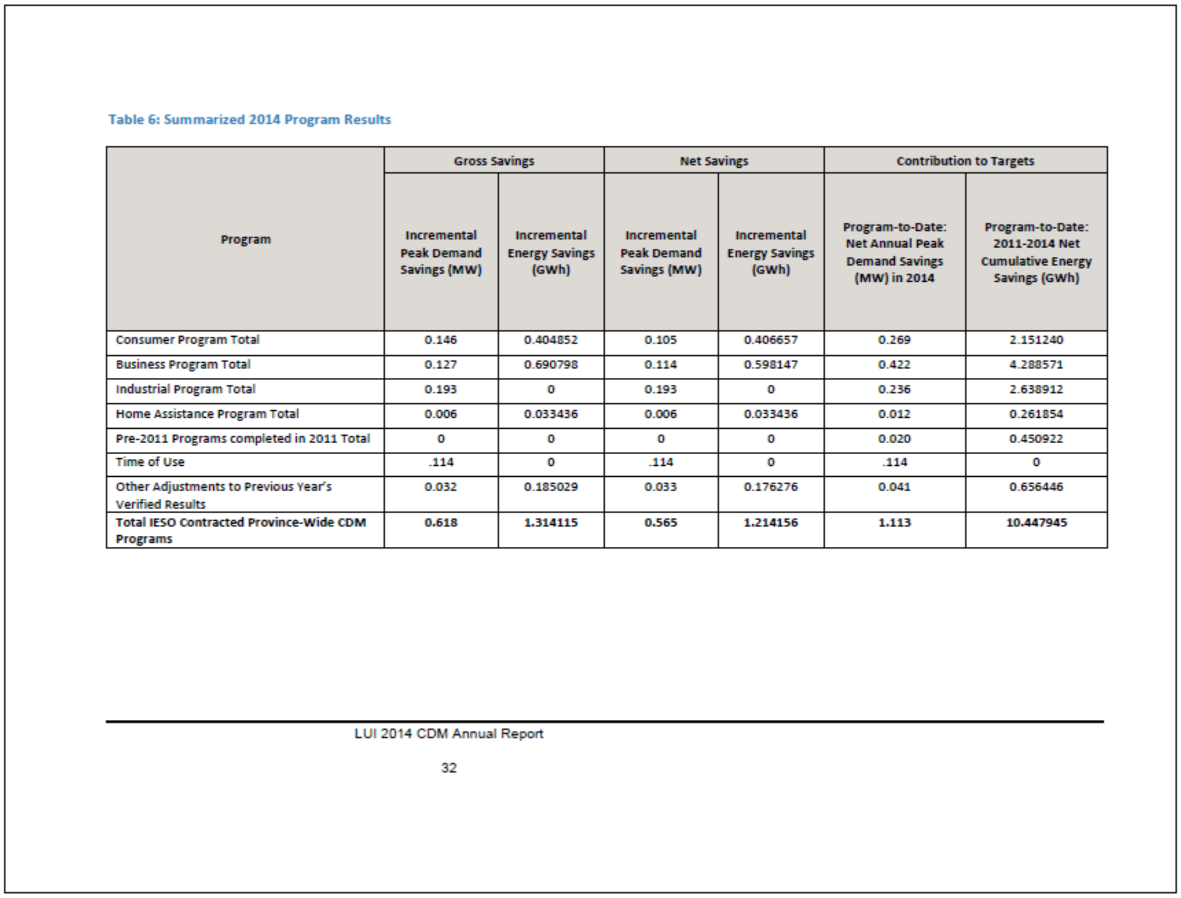
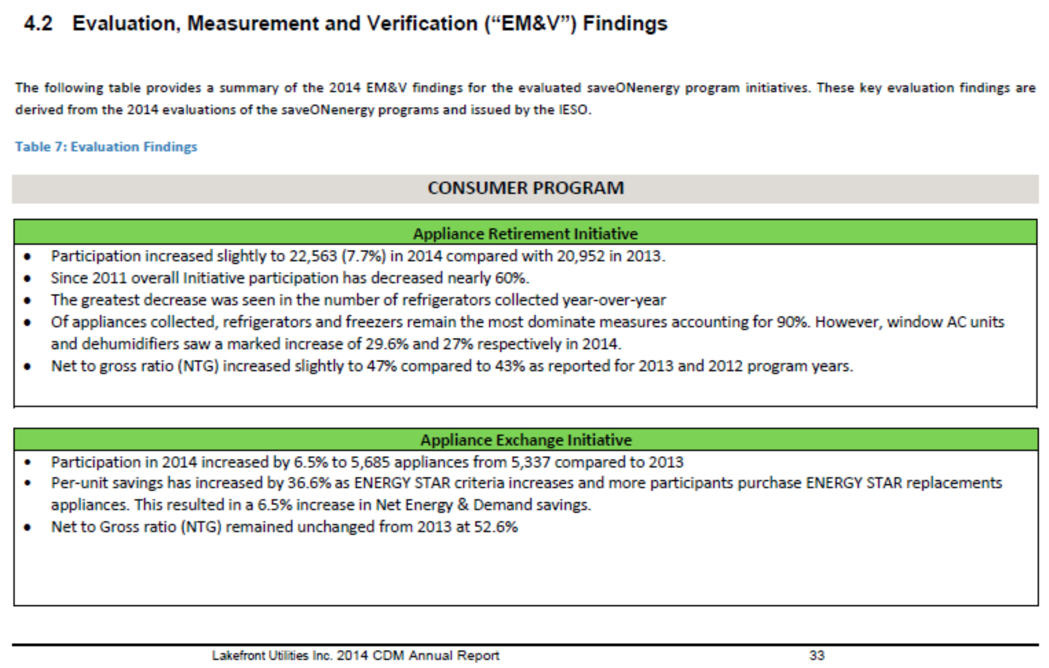


Table 6: Summarized 2014 Program Results

Program	Gross Savings		Net Savings		Contribution to Targets	
	Incremental Peak Demand Savings (MW)	Incremental Energy Savings (GWh)	Incremental Peak Demand Savings (MW)	Incremental Energy Savings (GWh)	Program-to-Date: Net Annual Peak Demand Savings (MW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (GWh)
Consumer Program Total	0.146	0.404852	0.105	0.406657	0.269	2.151240
Business Program Total	0.127	0.690798	0.114	0.598147	0.422	4.288571
Industrial Program Total	0.193	0	0.193	0	0.236	2.638912
Home Assistance Program Total	0.006	0.033436	0.006	0.033436	0.012	0.261854
Pre-2011 Programs completed in 2011 Total	0	0	0	0	0.020	0.450922
Time of Use	.114	0	.114	0	.114	0
Other Adjustments to Previous Year's Verified Results	0.032	0.185029	0.033	0.176276	0.041	0.656446
Total IESO Contracted Province-Wide CDM Programs	**0.618**	**1.314115**	**0.565**	**1.214156**	**1.113**	**10.447945**



4.2 Evaluation, Measurement and Verification ("EM&V") Findings

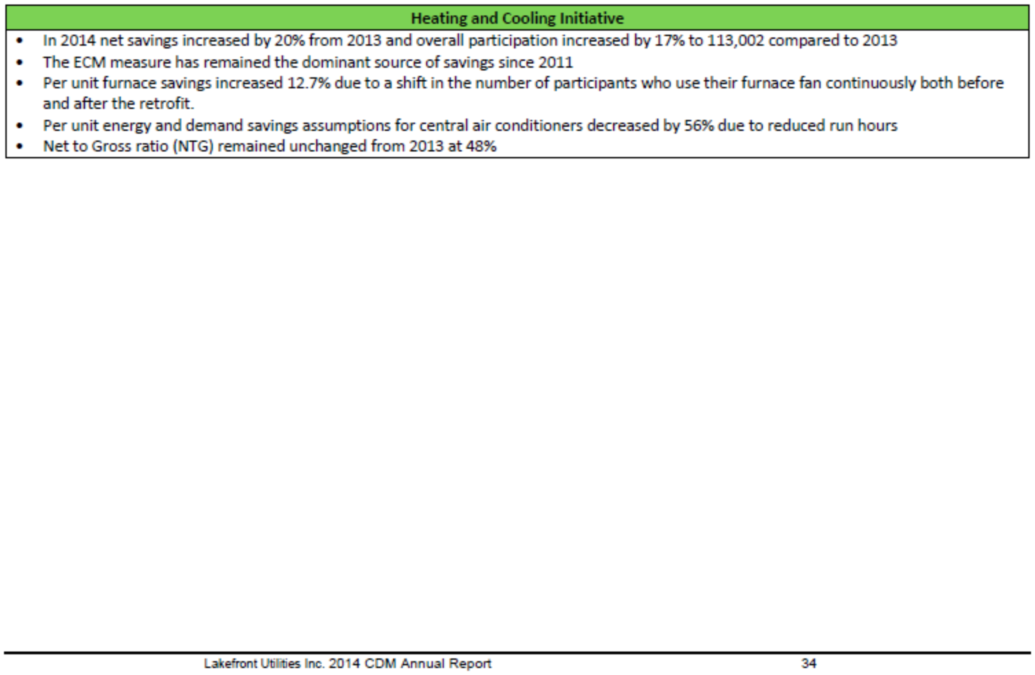
The following table provides a summary of the 2014 EM&V findings for the evaluated saveONenergy program initiatives. These key evaluation findings are derived from the 2014 evaluations of the saveONenergy programs and issued by the IESO.

Table 7: Evaluation Findings

CONSUMER PROGRAM

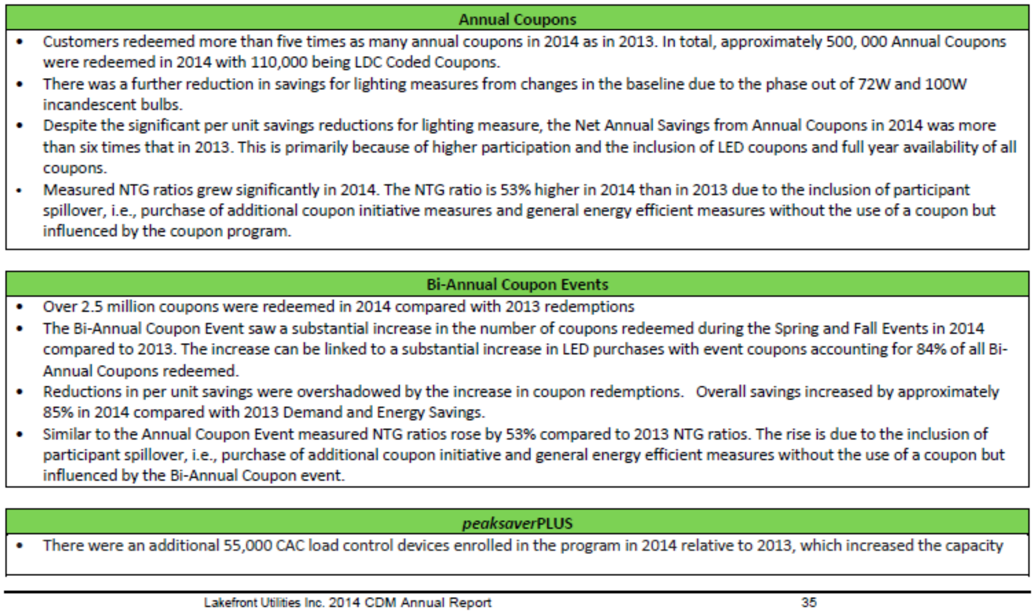
Appliance Retirement Initiative
• Participation increased slightly to 22,563 (7.7%) in 2014 compared with 20,952 in 2013. • Since 2011 overall Initiative participation has decreased nearly 60%. • The greatest decrease was seen in the number of refrigerators collected year-over-year • Of appliances collected, refrigerators and freezers remain the most dominate measures accounting for 90%. However, window AC units and dehumidifiers saw a marked increase of 29.6% and 27% respectively in 2014. • Net to gross ratio (NTG) increased slightly to 47% compared to 43% as reported for 2013 and 2012 program years.

Appliance Exchange Initiative
• Participation in 2014 increased by 6.5% to 5,685 appliances from 5,337 compared to 2013 • Per-unit savings has increased by 36.6% as ENERGY STAR criteria increases and more participants purchase ENERGY STAR replacements appliances. This resulted in a 6.5% increase in Net Energy & Demand savings. • Net to Gross ratio (NTG) remained unchanged from 2013 at 52.6%



Heating and Cooling Initiative

- In 2014 net savings increased by 20% from 2013 and overall participation increased by 17% to 113,002 compared to 2013
- The ECM measure has remained the dominant source of savings since 2011
- Per unit furnace savings increased 12.7% due to a shift in the number of participants who use their furnace fan continuously both before and after the retrofit.
- Per unit energy and demand savings assumptions for central air conditioners decreased by 56% due to reduced run hours
- Net to Gross ratio (NTG) remained unchanged from 2013 at 48%



Annual Coupons

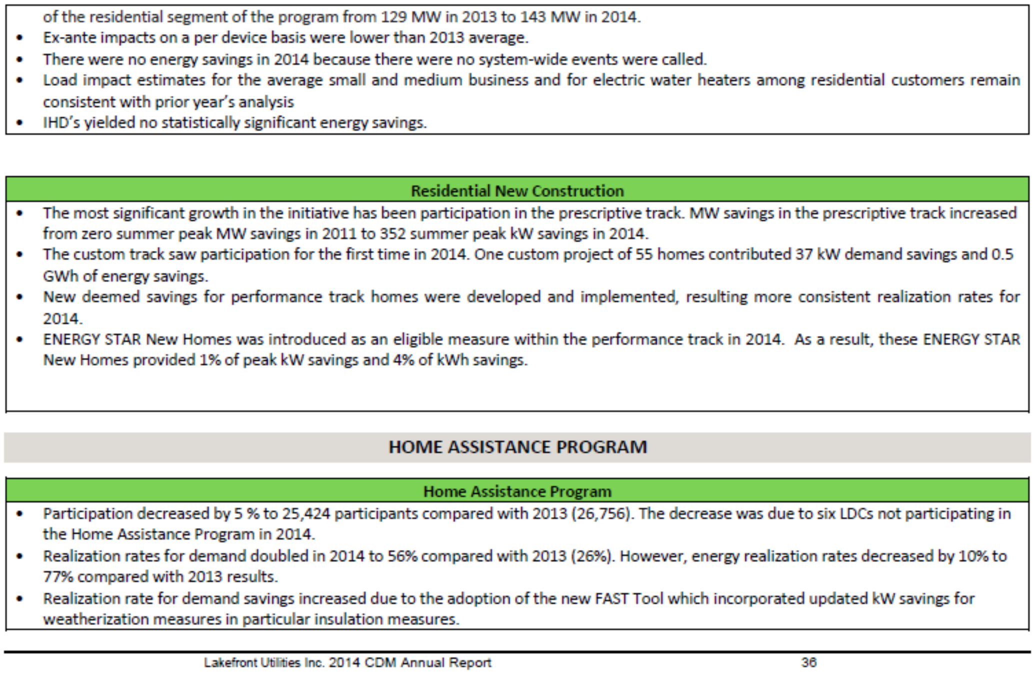
- Customers redeemed more than five times as many annual coupons in 2014 as in 2013. In total, approximately 500, 000 Annual Coupons were redeemed in 2014 with 110,000 being LDC Coded Coupons.
- There was a further reduction in savings for lighting measures from changes in the baseline due to the phase out of 72W and 100W incandescent bulbs.
- Despite the significant per unit savings reductions for lighting measure, the Net Annual Savings from Annual Coupons in 2014 was more than six times that in 2013. This is primarily because of higher participation and the inclusion of LED coupons and full year availability of all coupons.
- Measured NTG ratios grew significantly in 2014. The NTG ratio is 53% higher in 2014 than in 2013 due to the inclusion of participant spillover, i.e., purchase of additional coupon initiative measures and general energy efficient measures without the use of a coupon but influenced by the coupon program.

Bi-Annual Coupon Events

- Over 2.5 million coupons were redeemed in 2014 compared with 2013 redemptions
- The Bi-Annual Coupon Event saw a substantial increase in the number of coupons redeemed during the Spring and Fall Events in 2014 compared to 2013. The increase can be linked to a substantial increase in LED purchases with event coupons accounting for 84% of all Bi-Annual Coupons redeemed.
- Reductions in per unit savings were overshadowed by the increase in coupon redemptions. Overall savings increased by approximately 85% in 2014 compared with 2013 Demand and Energy Savings.
- Similar to the Annual Coupon Event measured NTG ratios rose by 53% compared to 2013 NTG ratios. The rise is due to the inclusion of participant spillover, i.e., purchase of additional coupon initiative and general energy efficient measures without the use of a coupon but influenced by the Bi-Annual Coupon event.

***peaksaver*PLUS**

- There were an additional 55,000 CAC load control devices enrolled in the program in 2014 relative to 2013, which increased the capacity



of the residential segment of the program from 129 MW in 2013 to 143 MW in 2014.

- Ex-ante impacts on a per device basis were lower than 2013 average.
- There were no energy savings in 2014 because there were no system-wide events were called.
- Load impact estimates for the average small and medium business and for electric water heaters among residential customers remain consistent with prior year's analysis
- IHD's yielded no statistically significant energy savings.

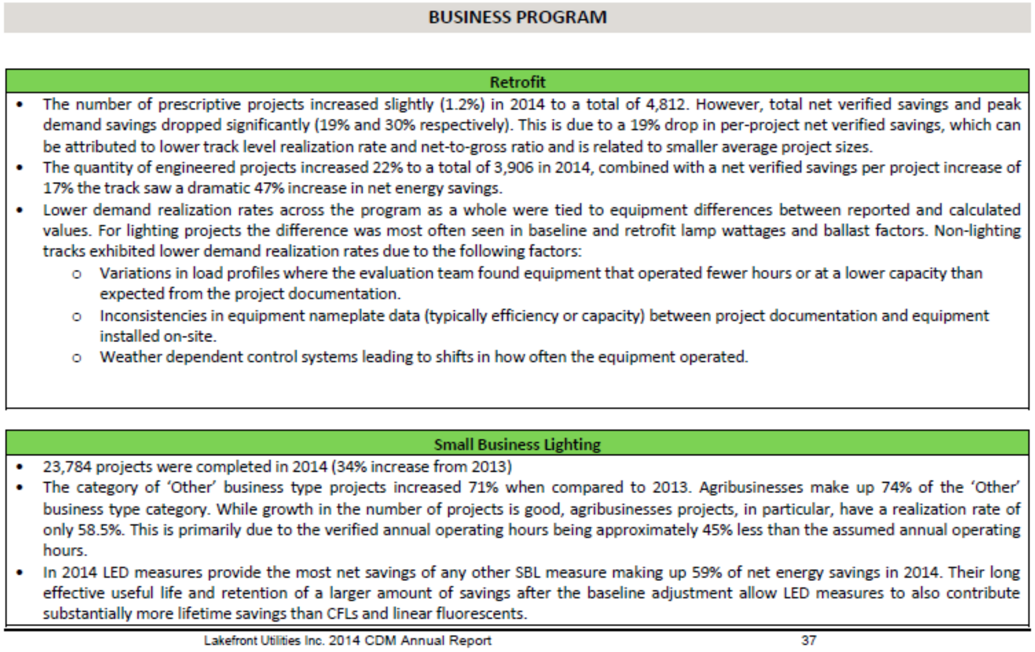
Residential New Construction

- The most significant growth in the initiative has been participation in the prescriptive track. MW savings in the prescriptive track increased from zero summer peak MW savings in 2011 to 352 summer peak kW savings in 2014.
- The custom track saw participation for the first time in 2014. One custom project of 55 homes contributed 37 kW demand savings and 0.5 GWh of energy savings.
- New deemed savings for performance track homes were developed and implemented, resulting more consistent realization rates for 2014.
- ENERGY STAR New Homes was introduced as an eligible measure within the performance track in 2014. As a result, these ENERGY STAR New Homes provided 1% of peak kW savings and 4% of kWh savings.

HOME ASSISTANCE PROGRAM

Home Assistance Program

- Participation decreased by 5 % to 25,424 participants compared with 2013 (26,756). The decrease was due to six LDCs not participating in the Home Assistance Program in 2014.
- Realization rates for demand doubled in 2014 to 56% compared with 2013 (26%). However, energy realization rates decreased by 10% to 77% compared with 2013 results.
- Realization rate for demand savings increased due to the adoption of the new FAST Tool which incorporated updated kW savings for weatherization measures in particular insulation measures.



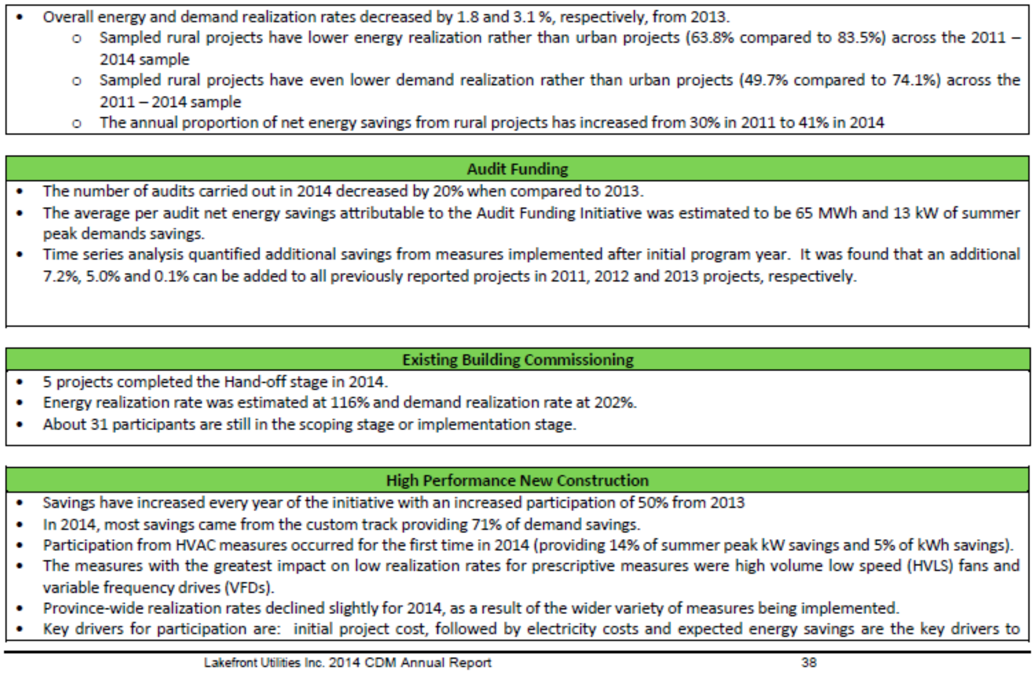
BUSINESS PROGRAM

Retrofit

- The number of prescriptive projects increased slightly (1.2%) in 2014 to a total of 4,812. However, total net verified savings and peak demand savings dropped significantly (19% and 30% respectively). This is due to a 19% drop in per-project net verified savings, which can be attributed to lower track level realization rate and net-to-gross ratio and is related to smaller average project sizes.
- The quantity of engineered projects increased 22% to a total of 3,906 in 2014, combined with a net verified savings per project increase of 17% the track saw a dramatic 47% increase in net energy savings.
- Lower demand realization rates across the program as a whole were tied to equipment differences between reported and calculated values. For lighting projects the difference was most often seen in baseline and retrofit lamp wattages and ballast factors. Non-lighting tracks exhibited lower demand realization rates due to the following factors:
    - Variations in load profiles where the evaluation team found equipment that operated fewer hours or at a lower capacity than expected from the project documentation.
    - Inconsistencies in equipment nameplate data (typically efficiency or capacity) between project documentation and equipment installed on-site.
    - Weather dependent control systems leading to shifts in how often the equipment operated.

Small Business Lighting

- 23,784 projects were completed in 2014 (34% increase from 2013)
- The category of 'Other' business type projects increased 71% when compared to 2013. Agribusinesses make up 74% of the 'Other' business type category. While growth in the number of projects is good, agribusinesses projects, in particular, have a realization rate of only 58.5%. This is primarily due to the verified annual operating hours being approximately 45% less than the assumed annual operating hours.
- In 2014 LED measures provide the most net savings of any other SBL measure making up 59% of net energy savings in 2014. Their long effective useful life and retention of a larger amount of savings after the baseline adjustment allow LED measures to also contribute substantially more lifetime savings than CFLs and linear fluorescents.



- Overall energy and demand realization rates decreased by 1.8 and 3.1 %, respectively, from 2013.
  - Sampled rural projects have lower energy realization rather than urban projects (63.8% compared to 83.5%) across the 2011 – 2014 sample
  - Sampled rural projects have even lower demand realization rather than urban projects (49.7% compared to 74.1%) across the 2011 – 2014 sample
  - The annual proportion of net energy savings from rural projects has increased from 30% in 2011 to 41% in 2014

Audit Funding

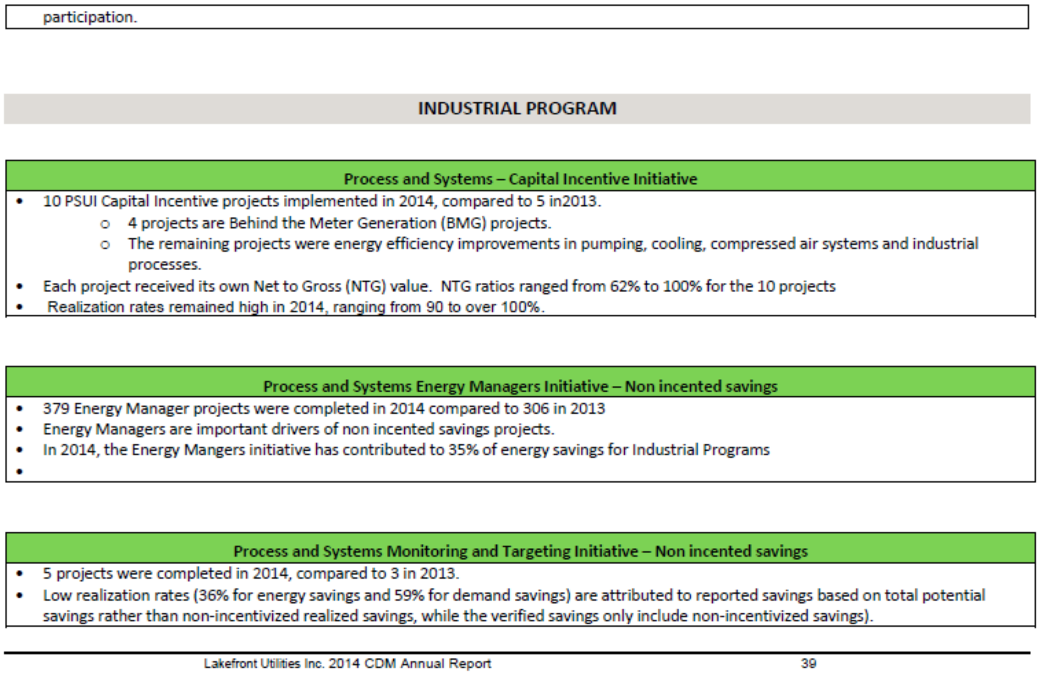
- The number of audits carried out in 2014 decreased by 20% when compared to 2013.
- The average per audit net energy savings attributable to the Audit Funding Initiative was estimated to be 65 MWh and 13 kW of summer peak demands savings.
- Time series analysis quantified additional savings from measures implemented after initial program year. It was found that an additional 7.2%, 5.0% and 0.1% can be added to all previously reported projects in 2011, 2012 and 2013 projects, respectively.

Existing Building Commissioning

- 5 projects completed the Hand-off stage in 2014.
- Energy realization rate was estimated at 116% and demand realization rate at 202%.
- About 31 participants are still in the scoping stage or implementation stage.

High Performance New Construction

- Savings have increased every year of the initiative with an increased participation of 50% from 2013
- In 2014, most savings came from the custom track providing 71% of demand savings.
- Participation from HVAC measures occurred for the first time in 2014 (providing 14% of summer peak kW savings and 5% of kWh savings).
- The measures with the greatest impact on low realization rates for prescriptive measures were high volume low speed (HVLS) fans and variable frequency drives (VFDs).
- Province-wide realization rates declined slightly for 2014, as a result of the wider variety of measures being implemented.
- Key drivers for participation are: initial project cost, followed by electricity costs and expected energy savings are the key drivers to



participation.

INDUSTRIAL PROGRAM

Process and Systems – Capital Incentive Initiative

- 10 PSUI Capital Incentive projects implemented in 2014, compared to 5 in2013.
    - 4 projects are Behind the Meter Generation (BMG) projects.
    - The remaining projects were energy efficiency improvements in pumping, cooling, compressed air systems and industrial processes.
- Each project received its own Net to Gross (NTG) value. NTG ratios ranged from 62% to 100% for the 10 projects
- Realization rates remained high in 2014, ranging from 90 to over 100%.

Process and Systems Energy Managers Initiative – Non incented savings

- 379 Energy Manager projects were completed in 2014 compared to 306 in 2013
- Energy Managers are important drivers of non incented savings projects.
- In 2014, the Energy Mangers initiative has contributed to 35% of energy savings for Industrial Programs
-

Process and Systems Monitoring and Targeting Initiative – Non incented savings

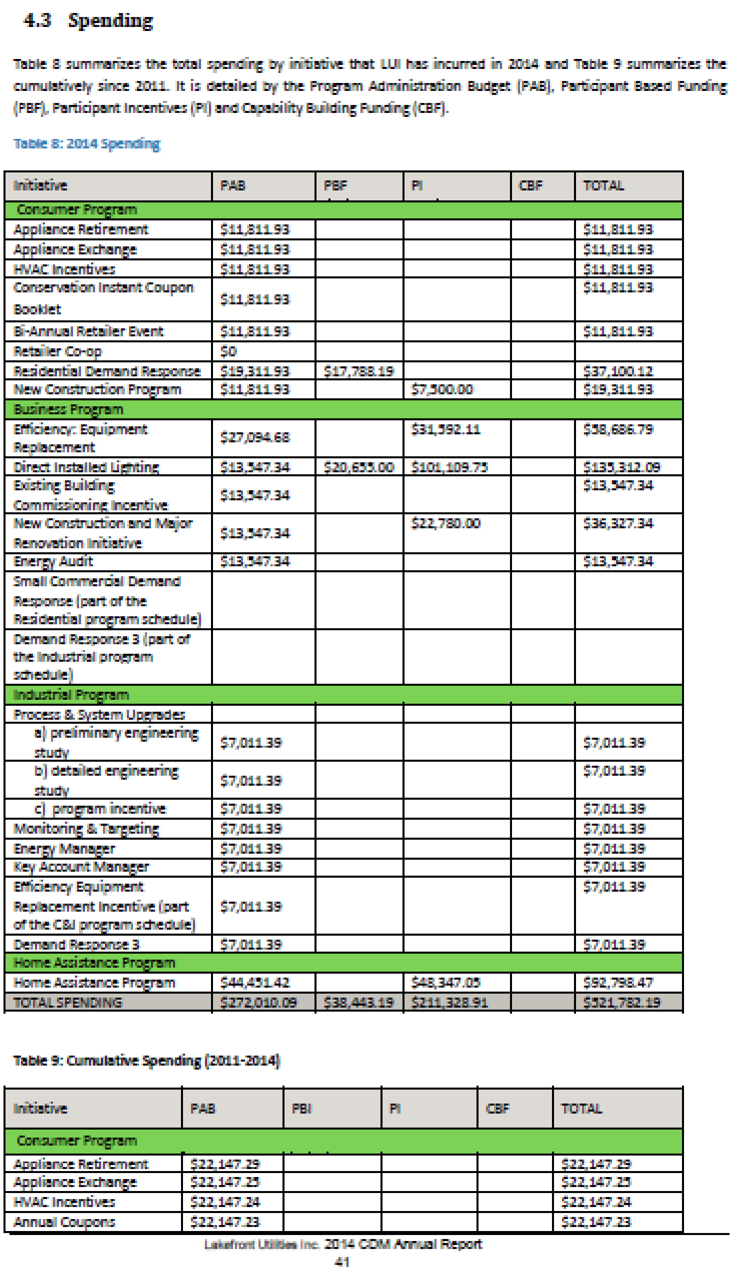
- 5 projects were completed in 2014, compared to 3 in 2013.
- Low realization rates (36% for energy savings and 59% for demand savings) are attributed to reported savings based on total potential savings rather than non-incentivized realized savings, while the verified savings only include non-incentivized savings).

Demand Response - DR-3

- The largest 25 contributors account for 60% of the contractual demand reduction – that is, less than 4% of contributors account for the majority of the load reductions.
- A multi-year analysis indicates 2012 was the best year for program performance. After 2012, a single large contributor left the program, resulting in a decrease in overall performance in 2013 and 2014. This highlights the risk having a highly concentrated program with a few large contributors representing a large share of the program capacity.
- There were no events called in 2014 and the contracted capacity was similar to 2013.

Note:

The Key Evaluation findings are derived from the 2014 evaluations of the saveONenergy programs. These findings were developed by 3rd party evaluation contractors. Complete findings are detailed in the contractors' full evaluation reports, which will be available publicly in Q4 2015.



4.3 Spending

Table 8 summarizes the total spending by initiative that LUI has incurred in 2014 and Table 9 summarizes the cumulatively since 2011. It is detailed by the Program Administration Budget (PAB), Participant Based Funding (PBF), Participant Incentives (PI) and Capability Building Funding (CBF).

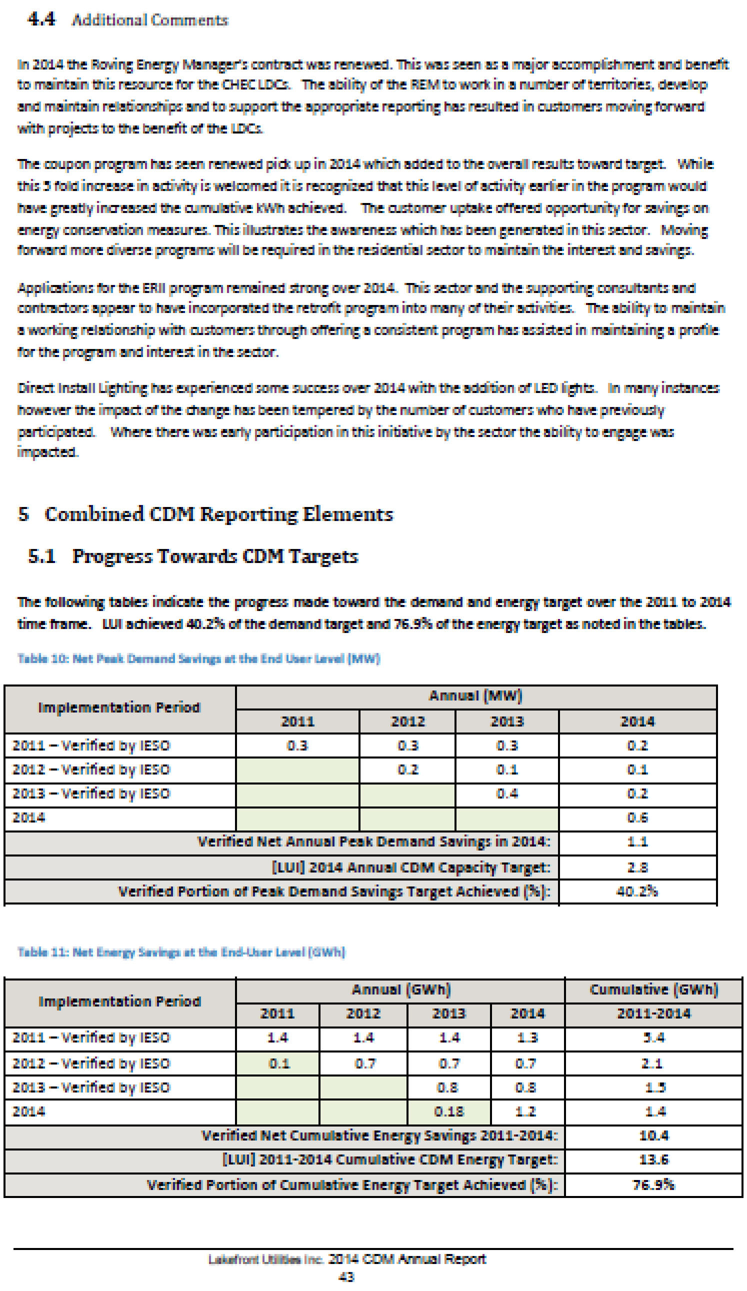
Table 8: 2014 Spending

Initiative	PAB	PBF	PI	CBF	TOTAL
Consumer Program					
Appliance Retirement	$11,811.93				$11,811.93
Appliance Exchange	$11,811.93				$11,811.93
HVAC Incentives	$11,811.93				$11,811.93
Conservation Instant Coupon Booklet	$11,811.93				$11,811.93
Bi-Annual Retailer Event	$11,811.93				$11,811.93
Retailer Co-op	$0				
Residential Demand Response	$19,311.93	$17,788.19			$37,100.12
New Construction Program	$11,811.93		$7,500.00		$19,311.93
Business Program					
Efficiency: Equipment Replacement	$27,094.68		$31,592.11		$58,686.79
Direct Installed Lighting	$13,547.34	$20,655.00	$101,109.75		$135,312.09
Existing Building Commissioning Incentive	$13,547.34				$13,547.34
New Construction and Major Renovation Initiative	$13,547.34		$22,780.00		$36,327.34
Energy Audit	$13,547.34				$13,547.34
Small Commercial Demand Response (part of the Residential program schedule)					
Demand Response 3 (part of the Industrial program schedule)					
Industrial Program					
Process & System Upgrades					
a) preliminary engineering study	$7,011.39				$7,011.39
b) detailed engineering study	$7,011.39				$7,011.39
c) program incentive	$7,011.39				$7,011.39
Monitoring & Targeting	$7,011.39				$7,011.39
Energy Manager	$7,011.39				$7,011.39
Key Account Manager	$7,011.39				$7,011.39
Efficiency Equipment Replacement Incentive (part of the C&I program schedule)	$7,011.39				$7,011.39
Demand Response 3	$7,011.39				$7,011.39
Home Assistance Program					
Home Assistance Program	$44,451.42		$48,347.05		$92,798.47
TOTAL SPENDING	$272,010.09	$38,443.19	$211,328.91		$521,782.19

Table 9: Cumulative Spending (2011-2014)

Initiative	PAB	PBI	PI	CBF	TOTAL
Consumer Program					
Appliance Retirement	$22,147.29				$22,147.29
Appliance Exchange	$22,147.25				$22,147.25
HVAC Incentives	$22,147.24				$22,147.24
Annual Coupons	$22,147.23				$22,147.23

Bi-Annual Retailer Event	$22,147.23				$22,147.23
Retailer Co-op	$0				$0
Residential Demand Response	$29,647.26	$17,788.19			$47,435.45
New Construction Program	$22,147.21		$7,500.00		$29,647.21
Business Program					
Equipment Replacement	$39,316.00		$178,164.16		$217,480.16
Direct Installed Lighting	$25,774.65	$68,340.00	$282,226.74		$376,341.39
Existing Building Commissioning Incentive	$25,768.60				$25,768.60
New Construction and Major Renovation Initiative	$25,768.64		$22,780.00		$48,548.64
Energy Audit	$25,768.64				$25,768.64
Small Commercial Demand Response	$9,407.19				$9,407.19
Demand Response	$2,814.09				$2,814.09
Industrial Program					
Process & System Upgrades					
a) preliminary engineering study	$12,402.42				$12,402.42
b) detailed engineering study	$12,402.42				$12,402.42
c) program incentive	$12,402.44				$12,402.44
Monitoring & Targeting	$12,402.43				$12,402.43
Energy Manager	$12,402.43				$12,402.43
Key Account Manager ("KAM")					
Equipment Replacement Incentive	$16,252.92				$16,252.92
Demand Response 3	$13,942.89				$13,942.89
Home Assistance Program					
Home Assistance Program	$38,205.46	$26,100.00	$71,283.75		$135,589.21
Pre 2011 Programs					
Electricity Retrofit Incentive Program					
High Performance New Construction					
Toronto Comprehensive					
Multifamily Energy Efficiency Rebates					
Data Centre Incentive Program					
EnWin Green Suites					
Initiatives Not In Market					
Midstream Electronics					
Midstream Pool Equipment					
Demand Service Space Cooling					
Demand Response 1					
Home Energy Audit Tool					
Total CDM Program Spending	$467,561.93	$112,228.19	$561,954.65		$1,141,744.70



4.4 Additional Comments

In 2014 the Roving Energy Manager's contract was renewed. This was seen as a major accomplishment and benefit to maintain this resource for the CHEC LDCs. The ability of the REM to work in a number of territories, develop and maintain relationships and to support the appropriate reporting has resulted in customers moving forward with projects to the benefit of the LDCs.

The coupon program has seen renewed pick up in 2014 which added to the overall results toward target. While this 5 fold increase in activity is welcomed it is recognized that this level of activity earlier in the program would have greatly increased the cumulative kWh achieved. The customer uptake offered opportunity for savings on energy conservation measures. This illustrates the awareness which has been generated in this sector. Moving forward more diverse programs will be required in the residential sector to maintain the interest and savings.

Applications for the ERII program remained strong over 2014. This sector and the supporting consultants and contractors appear to have incorporated the retrofit program into many of their activities. The ability to maintain a working relationship with customers through offering a consistent program has assisted in maintaining a profile for the program and interest in the sector.

Direct Install Lighting has experienced some success over 2014 with the addition of LED lights. In many instances however the impact of the change has been tempered by the number of customers who have previously participated. Where there was early participation in this initiative by the sector the ability to engage was impacted.

5 Combined CDM Reporting Elements

5.1 Progress Towards CDM Targets

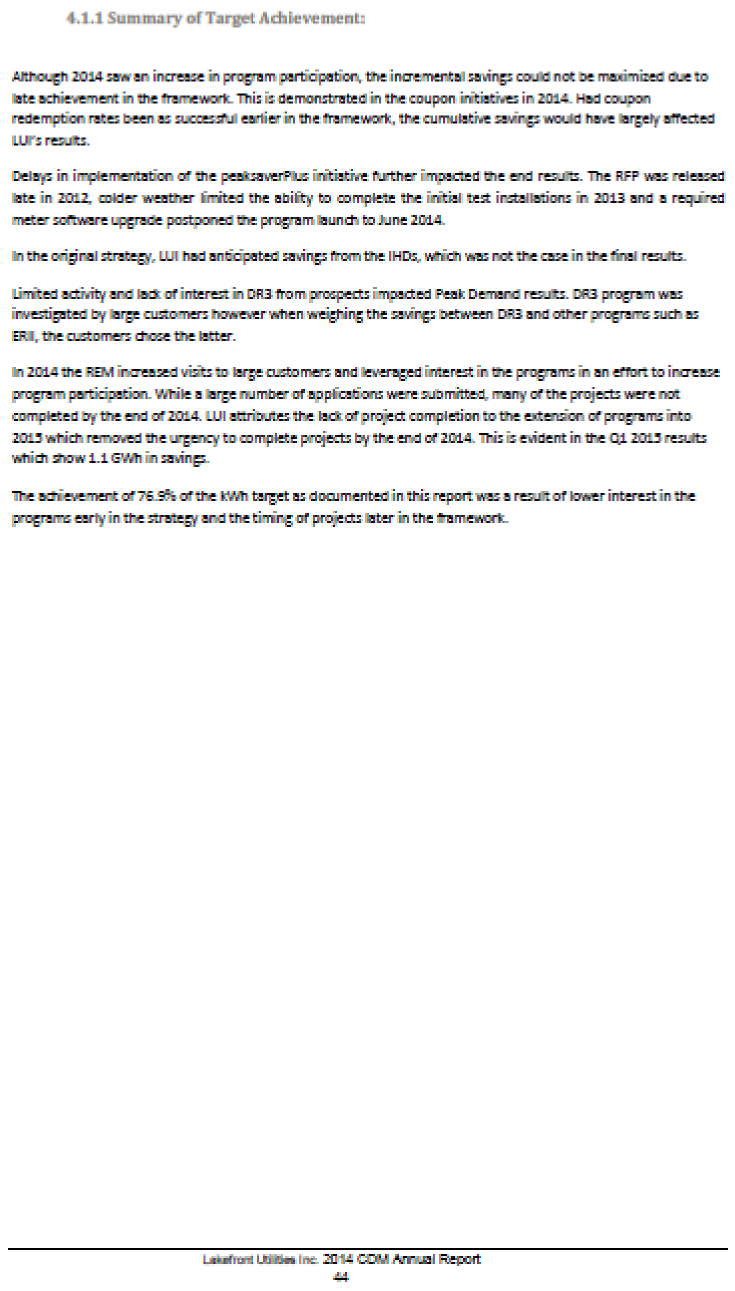
The following tables indicate the progress made toward the demand and energy target over the 2011 to 2014 time frame. LUI achieved 40.2% of the demand target and 76.9% of the energy target as noted in the tables.

Table 10: Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual (MW)			
	2011	2012	2013	2014
2011 – Verified by IESO	0.3	0.3	0.3	0.2
2012 – Verified by IESO		0.2	0.1	0.1
2013 – Verified by IESO			0.4	0.2
2014				0.6
Verified Net Annual Peak Demand Savings in 2014:				1.1
[LUI] 2014 Annual CDM Capacity Target:				2.8
Verified Portion of Peak Demand Savings Target Achieved (%):				40.2%

Table 11: Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual (GWh)				Cumulative (GWh)
	2011	2012	2013	2014	2011-2014
2011 – Verified by IESO	1.4	1.4	1.4	1.3	5.4
2012 – Verified by IESO	0.1	0.7	0.7	0.7	2.1
2013 – Verified by IESO			0.8	0.8	1.5
2014			0.18	1.2	1.4
Verified Net Cumulative Energy Savings 2011-2014:					10.4
[LUI] 2011-2014 Cumulative CDM Energy Target:					13.6
Verified Portion of Cumulative Energy Target Achieved (%):					76.9%



4.1.1 Summary of Target Achievement:

Although 2014 saw an increase in program participation, the incremental savings could not be maximized due to late achievement in the framework. This is demonstrated in the coupon initiatives in 2014. Had coupon redemption rates been as successful earlier in the framework, the cumulative savings would have largely affected LUI's results.

Delays in implementation of the peaksaverPlus initiative further impacted the end results. The RFP was released late in 2012, colder weather limited the ability to complete the initial test installations in 2013 and a required meter software upgrade postponed the program launch to June 2014.

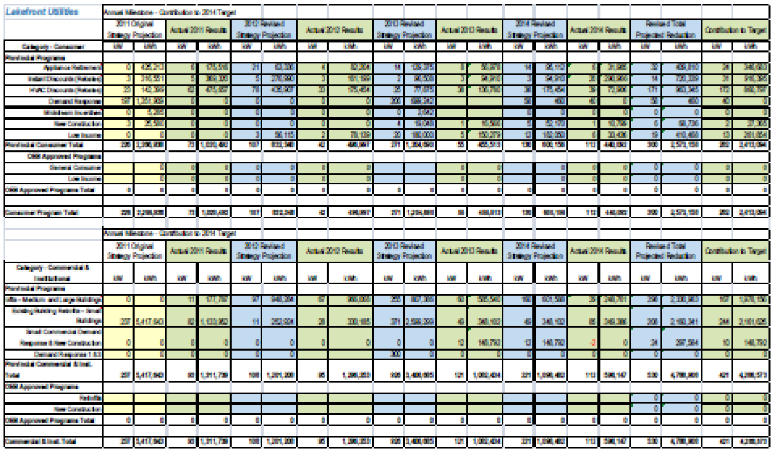
In the original strategy, LUI had anticipated savings from the IHDs, which was not the case in the final results.

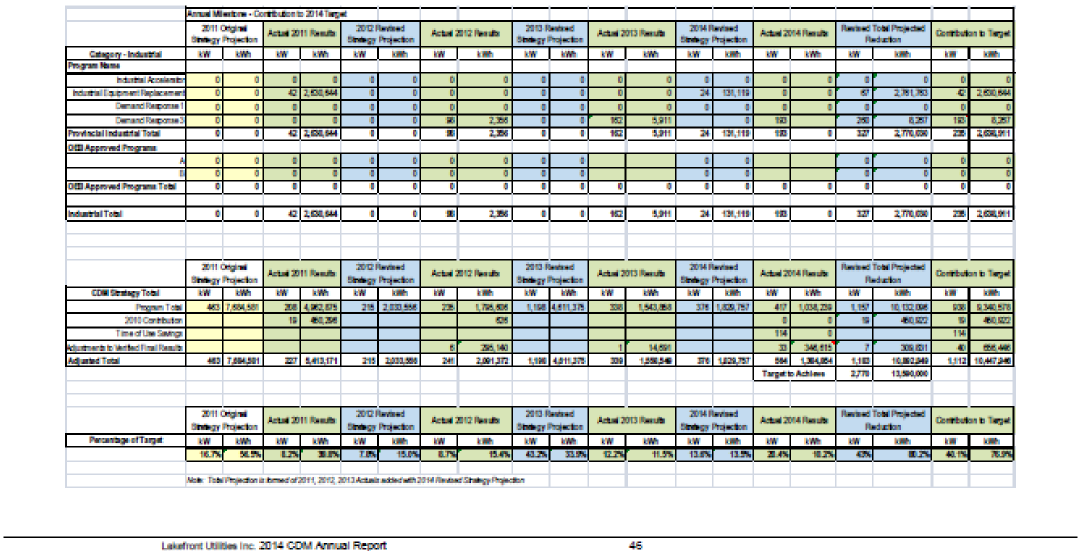
Limited activity and lack of interest in DR3 from prospects impacted Peak Demand results. DR3 program was investigated by large customers however when weighing the savings between DR3 and other programs such as ERII, the customers chose the latter.

In 2014 the REM increased visits to large customers and leveraged interest in the programs in an effort to increase program participation. While a large number of applications were submitted, many of the projects were not completed by the end of 2014. LUI attributes the lack of project completion to the extension of programs into 2015 which removed the urgency to complete projects by the end of 2014. This is evident in the Q1 2015 results which show 1.1 GWh in savings.

The achievement of 76.9% of the kWh target as documented in this report was a result of lower interest in the programs early in the strategy and the timing of projects later in the framework.

5.2 Variance from Strategy





Annual Milestone - Contribution to 2014 Target																				
	2011 Original Strategy Projection		Actual 2011 Results		2012 Revised Strategy Projection		Actual 2012 Results		2013 Revised Strategy Projection		Actual 2013 Results		2014 Revised Strategy Projection		Actual 2014 Results		Revised Total Projected Reduction		Contribution to Target	
Category - Industrial	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh
Program Name																				
Industrial Accelerator	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Industrial Equipment Replacement	0	0	42	2,630,644	0	0	0	0	0	0	0	0	24	131,119	0	0	67	2,761,763	42	2,630,644
Demand Response 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response 3	0	0	0	0	0	0	98	2,356	0	0	162	5,911		0	193		260	8,267	193	8,267
Provincial Industrial Total	0	0	42	2,630,644	0	0	98	2,356	0	0	162	5,911	24	131,119	193	0	327	2,770,030	236	2,638,911
OEB Approved Programs																				
A	0	0	0	0	0	0	0	0	0	0			0	0			0	0	0	0
B	0	0	0	0	0	0	0	0	0	0			0	0			0	0	0	0
OEB Approved Programs Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Industrial Total	0	0	42	2,630,644	0	0	98	2,356	0	0	162	5,911	24	131,119	193	0	327	2,770,030	236	2,638,911

	2011 Original Strategy Projection		Actual 2011 Results		2012 Revised Strategy Projection		Actual 2012 Results		2013 Revised Strategy Projection		Actual 2013 Results		2014 Revised Strategy Projection		Actual 2014 Results		Revised Total Projected Reduction		Contribution to Target	
CDM Strategy Total	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh
Program Total	463	7,684,581	208	4,962,875	215	2,033,556	235	1,795,606	1,198	4,611,375	338	1,543,858	376	1,829,757	417	1,038,239	1,157	10,132,096	938	9,340,578
2010 Contribution			19	460,296				626							0	0	19	460,922	19	460,922
Time of Use Savings															114	0			114	
Adjustments to Verified Final Results							6	295,140			1	14,591			33	346,515	7	309,731	40	656,246
Adjusted Total	463	7,684,581	227	5,423,171	215	2,033,556	241	2,091,372	1,198	4,611,375	339	1,558,449	376	1,829,757	564	1,384,754	1,183	10,902,749	1,112	10,447,246
															Target to Achieve		2,770	13,590,000		

	2011 Original Strategy Projection		Actual 2011 Results		2012 Revised Strategy Projection		Actual 2012 Results		2013 Revised Strategy Projection		Actual 2013 Results		2014 Revised Strategy Projection		Actual 2014 Results		Revised Total Projected Reduction		Contribution to Target	
Percentage of Target	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh
	16.7%	56.5%	8.2%	39.9%	7.8%	15.0%	8.7%	15.4%	43.2%	33.9%	12.2%	11.5%	13.6%	13.5%	20.4%	10.2%	43%	80.2%	40.1%	76.9%

Note: Total Projection is formed of 2011, 2012, 2013 Actuals added with 2014 Revised Strategy Projection

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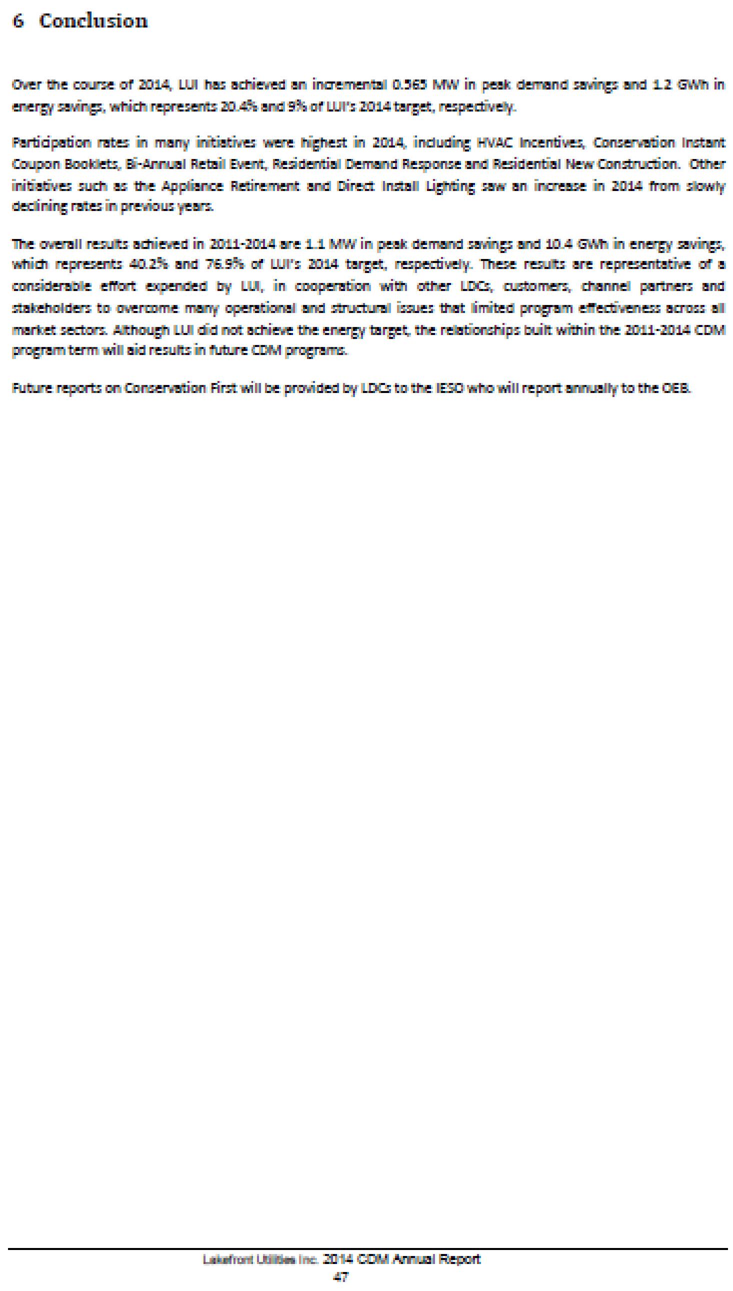


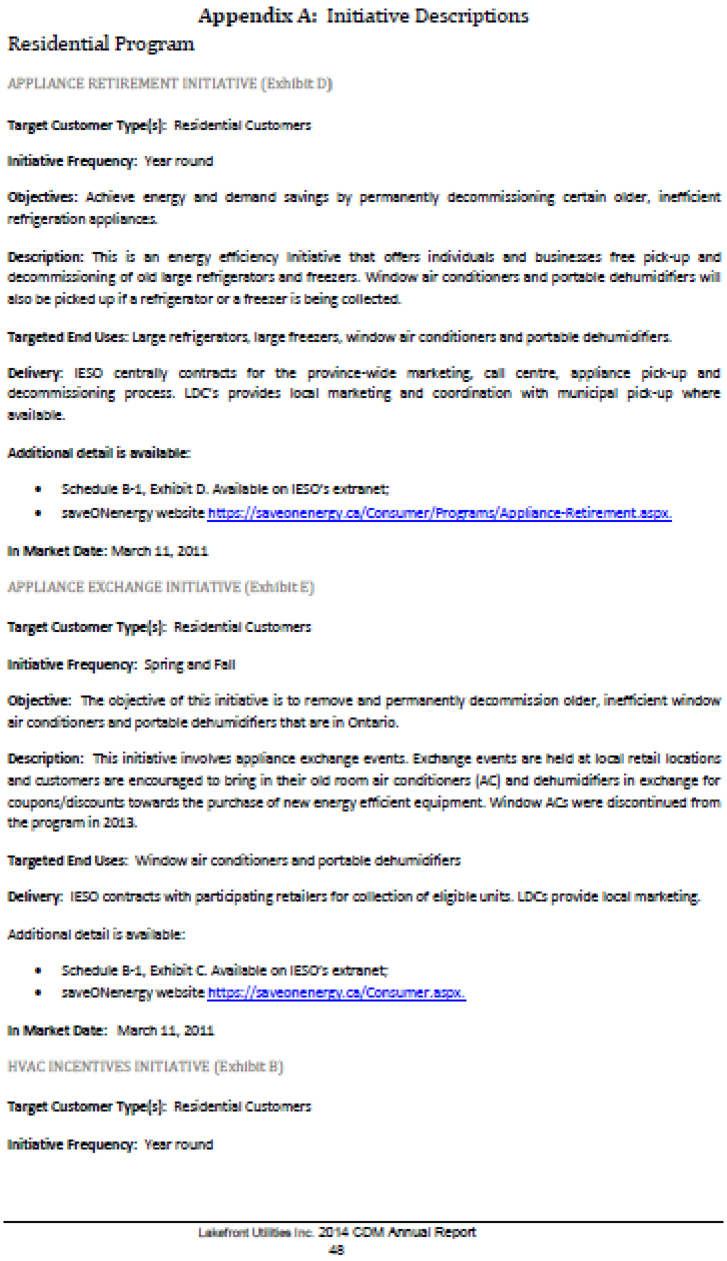
6 Conclusion

Over the course of 2014, LUI has achieved an incremental 0.565 MW in peak demand savings and 1.2 GWh in energy savings, which represents 20.4% and 9% of LUI's 2014 target, respectively.

Participation rates in many initiatives were highest in 2014, including HVAC Incentives, Conservation Instant Coupon Booklets, Bi-Annual Retail Event, Residential Demand Response and Residential New Construction. Other initiatives such as the Appliance Retirement and Direct Install Lighting saw an increase in 2014 from slowly declining rates in previous years.

The overall results achieved in 2011-2014 are 1.1 MW in peak demand savings and 10.4 GWh in energy savings, which represents 40.2% and 76.9% of LUI's 2014 target, respectively. These results are representative of a considerable effort expended by LUI, in cooperation with other LDCs, customers, channel partners and stakeholders to overcome many operational and structural issues that limited program effectiveness across all market sectors. Although LUI did not achieve the energy target, the relationships built within the 2011-2014 CDM program term will aid results in future CDM programs.

Future reports on Conservation First will be provided by LDCs to the IESO who will report annually to the OEB.



Appendix A: Initiative Descriptions

Residential Program

APPLIANCE RETIREMENT INITIATIVE (Exhibit D)

Target Customer Type(s): Residential Customers

Initiative Frequency: Year round

Objectives: Achieve energy and demand savings by permanently decommissioning certain older, inefficient refrigeration appliances.

Description: This is an energy efficiency Initiative that offers individuals and businesses free pick-up and decommissioning of old large refrigerators and freezers. Window air conditioners and portable dehumidifiers will also be picked up if a refrigerator or a freezer is being collected.

Targeted End Uses: Large refrigerators, large freezers, window air conditioners and portable dehumidifiers.

Delivery: IESO centrally contracts for the province-wide marketing, call centre, appliance pick-up and decommissioning process. LDC's provides local marketing and coordination with municipal pick-up where available.

Additional detail is available:

- Schedule B-1, Exhibit D. Available on IESO's extranet;
- saveONenergy website https://saveonenergy.ca/Consumer/Programs/Appliance-Retirement.aspx.

In Market Date: March 11, 2011

APPLIANCE EXCHANGE INITIATIVE (Exhibit E)

Target Customer Type(s): Residential Customers

Initiative Frequency: Spring and Fall

Objective: The objective of this initiative is to remove and permanently decommission older, inefficient window air conditioners and portable dehumidifiers that are in Ontario.

Description: This initiative involves appliance exchange events. Exchange events are held at local retail locations and customers are encouraged to bring in their old room air conditioners (AC) and dehumidifiers in exchange for coupons/discounts towards the purchase of new energy efficient equipment. Window ACs were discontinued from the program in 2013.

Targeted End Uses: Window air conditioners and portable dehumidifiers

Delivery: IESO contracts with participating retailers for collection of eligible units. LDCs provide local marketing.

Additional detail is available:

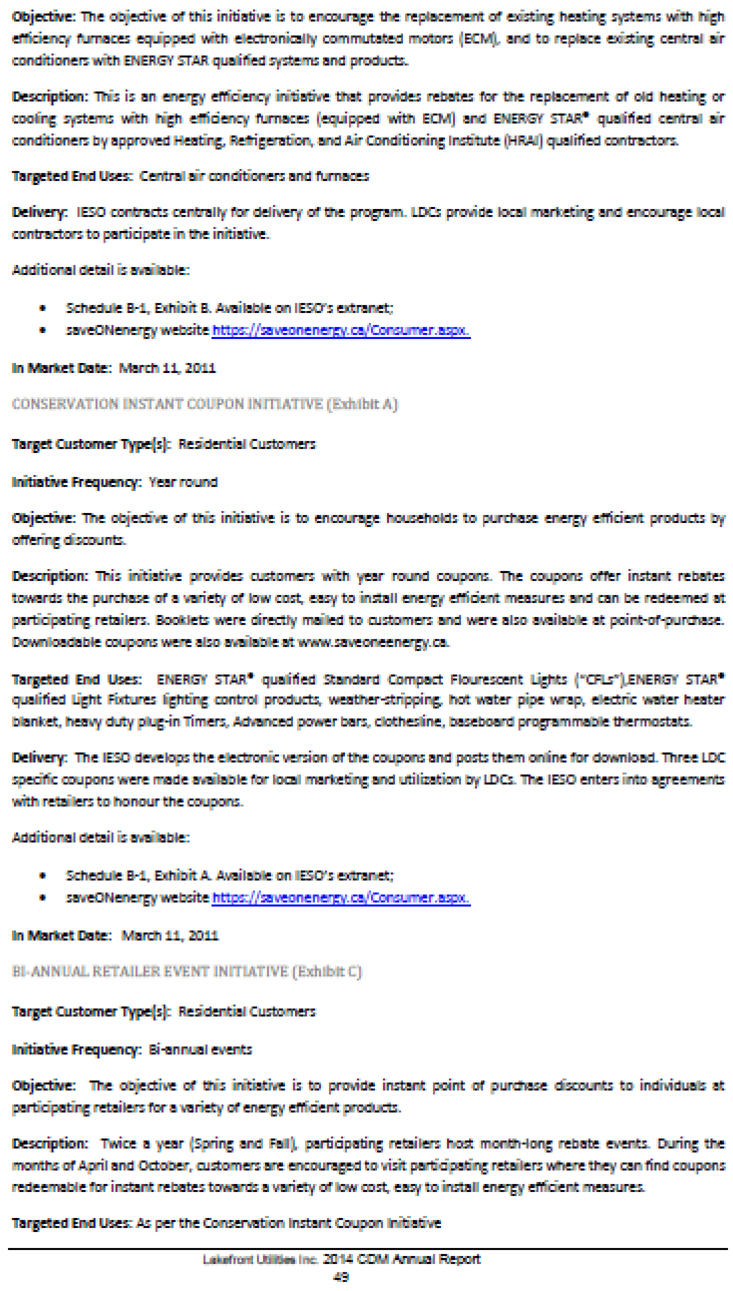
- Schedule B-1, Exhibit C. Available on IESO's extranet;
- saveONenergy website https://saveonenergy.ca/Consumer.aspx.

In Market Date: March 11, 2011

HVAC INCENTIVES INITIATIVE (Exhibit B)

Target Customer Type(s): Residential Customers

Initiative Frequency: Year round



Objective: The objective of this initiative is to encourage the replacement of existing heating systems with high efficiency furnaces equipped with electronically commutated motors (ECM), and to replace existing central air conditioners with ENERGY STAR qualified systems and products.

Description: This is an energy efficiency initiative that provides rebates for the replacement of old heating or cooling systems with high efficiency furnaces (equipped with ECM) and ENERGY STAR® qualified central air conditioners by approved Heating, Refrigeration, and Air Conditioning Institute (HRAI) qualified contractors.

Targeted End Uses: Central air conditioners and furnaces

Delivery: IESO contracts centrally for delivery of the program. LDCs provide local marketing and encourage local contractors to participate in the initiative.

Additional detail is available:

- Schedule B-1, Exhibit B. Available on IESO's extranet;
- saveONenergy website https://saveonenergy.ca/Consumer.aspx.

In Market Date: March 11, 2011

CONSERVATION INSTANT COUPON INITIATIVE (Exhibit A)

Target Customer Type(s): Residential Customers

Initiative Frequency: Year round

Objective: The objective of this initiative is to encourage households to purchase energy efficient products by offering discounts.

Description: This initiative provides customers with year round coupons. The coupons offer instant rebates towards the purchase of a variety of low cost, easy to install energy efficient measures and can be redeemed at participating retailers. Booklets were directly mailed to customers and were also available at point-of-purchase. Downloadable coupons were also available at www.saveoneenergy.ca.

Targeted End Uses: ENERGY STAR® qualified Standard Compact Flourescent Lights ("CFLs"),ENERGY STAR® qualified Light Fixtures lighting control products, weather-stripping, hot water pipe wrap, electric water heater blanket, heavy duty plug-in Timers, Advanced power bars, clothesline, baseboard programmable thermostats.

Delivery: The IESO develops the electronic version of the coupons and posts them online for download. Three LDC specific coupons were made available for local marketing and utilization by LDCs. The IESO enters into agreements with retailers to honour the coupons.

Additional detail is available:

- Schedule B-1, Exhibit A. Available on IESO's extranet;
- saveONenergy website https://saveonenergy.ca/Consumer.aspx.

In Market Date: March 11, 2011

BI-ANNUAL RETAILER EVENT INITIATIVE (Exhibit C)

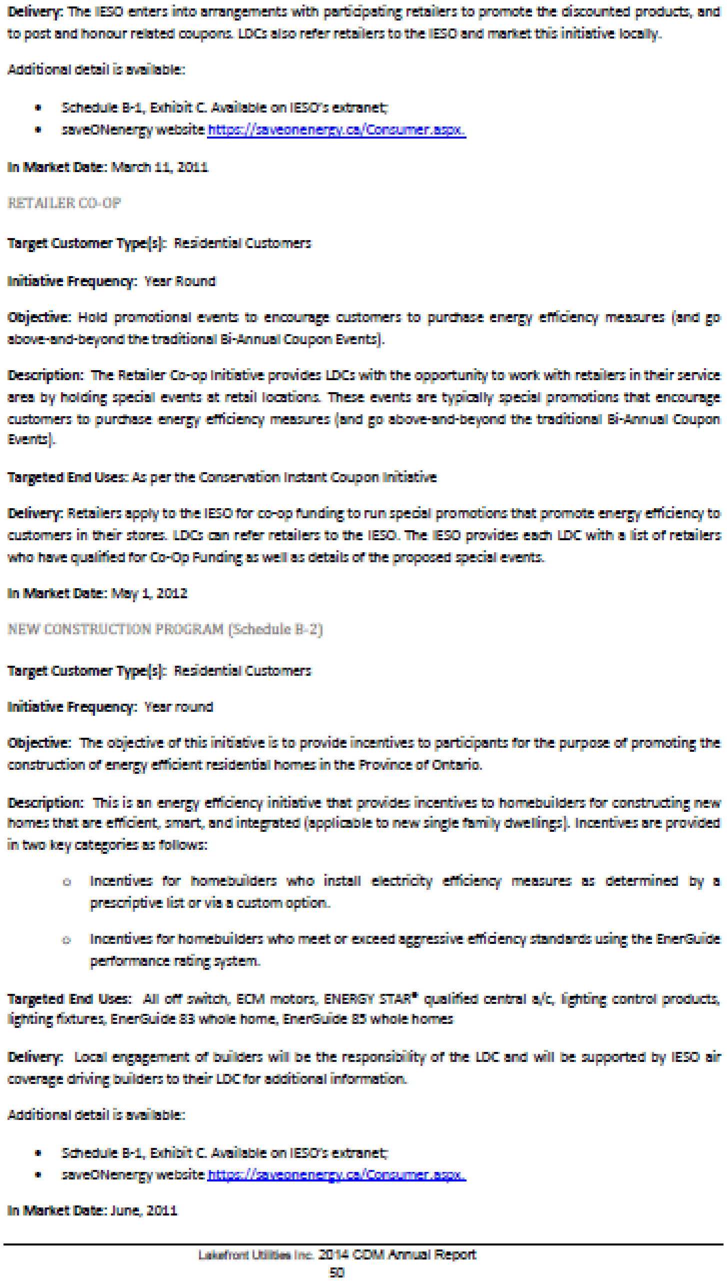
Target Customer Type(s): Residential Customers

Initiative Frequency: Bi-annual events

Objective: The objective of this initiative is to provide instant point of purchase discounts to individuals at participating retailers for a variety of energy efficient products.

Description: Twice a year (Spring and Fall), participating retailers host month-long rebate events. During the months of April and October, customers are encouraged to visit participating retailers where they can find coupons redeemable for instant rebates towards a variety of low cost, easy to install energy efficient measures.

Targeted End Uses: As per the Conservation Instant Coupon Initiative



Delivery: The IESO enters into arrangements with participating retailers to promote the discounted products, and to post and honour related coupons. LDCs also refer retailers to the IESO and market this initiative locally.

Additional detail is available:

- Schedule B-1, Exhibit C. Available on IESO's extranet;
- saveONenergy website https://saveonenergy.ca/Consumer.aspx.

In Market Date: March 11, 2011

RETAILER CO-OP

Target Customer Type(s): Residential Customers

Initiative Frequency: Year Round

Objective: Hold promotional events to encourage customers to purchase energy efficiency measures (and go above-and-beyond the traditional Bi-Annual Coupon Events).

Description: The Retailer Co-op Initiative provides LDCs with the opportunity to work with retailers in their service area by holding special events at retail locations. These events are typically special promotions that encourage customers to purchase energy efficiency measures (and go above-and-beyond the traditional Bi-Annual Coupon Events).

Targeted End Uses: As per the Conservation Instant Coupon Initiative

Delivery: Retailers apply to the IESO for co-op funding to run special promotions that promote energy efficiency to customers in their stores. LDCs can refer retailers to the IESO. The IESO provides each LDC with a list of retailers who have qualified for Co-Op Funding as well as details of the proposed special events.

In Market Date: May 1, 2012

NEW CONSTRUCTION PROGRAM (Schedule B-2)

Target Customer Type(s): Residential Customers

Initiative Frequency: Year round

Objective: The objective of this initiative is to provide incentives to participants for the purpose of promoting the construction of energy efficient residential homes in the Province of Ontario.

Description: This is an energy efficiency initiative that provides incentives to homebuilders for constructing new homes that are efficient, smart, and integrated (applicable to new single family dwellings). Incentives are provided in two key categories as follows:

- Incentives for homebuilders who install electricity efficiency measures as determined by a prescriptive list or via a custom option.
- Incentives for homebuilders who meet or exceed aggressive efficiency standards using the EnerGuide performance rating system.

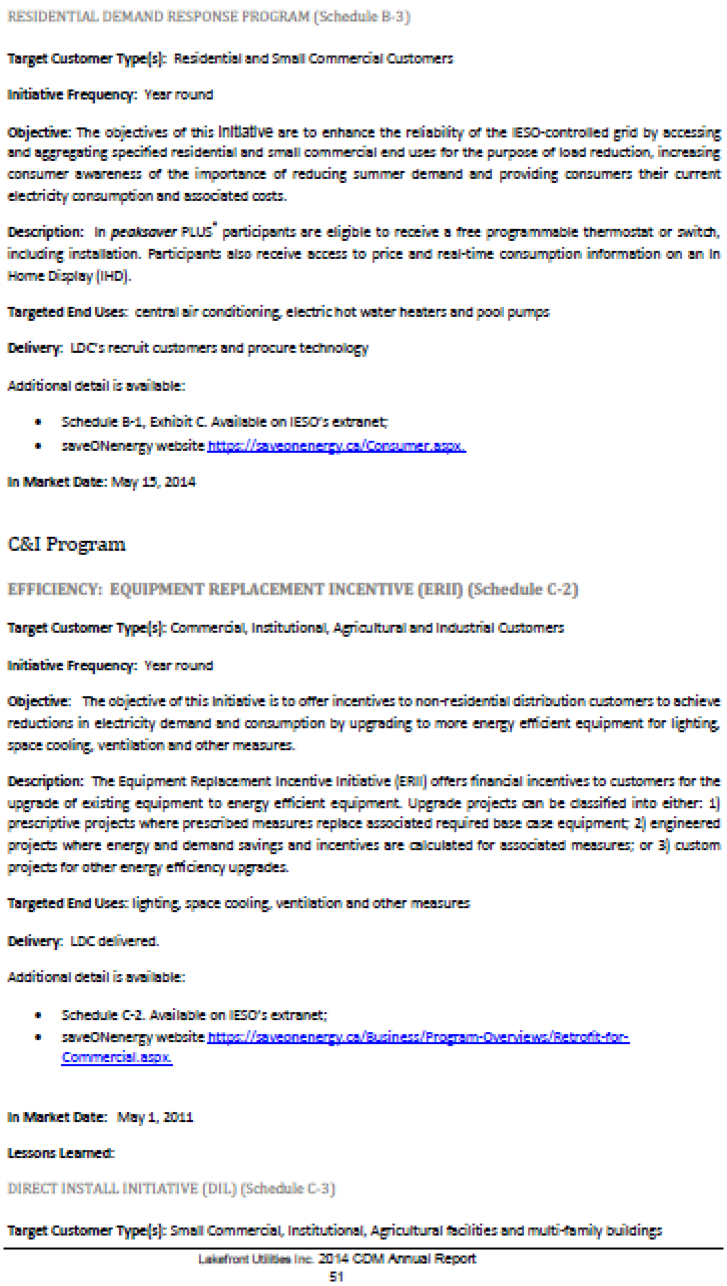
Targeted End Uses: All off switch, ECM motors, ENERGY STAR® qualified central a/c, lighting control products, lighting fixtures, EnerGuide 83 whole home, EnerGuide 85 whole homes

Delivery: Local engagement of builders will be the responsibility of the LDC and will be supported by IESO air coverage driving builders to their LDC for additional information.

Additional detail is available:

- Schedule B-1, Exhibit C. Available on IESO's extranet;
- saveONenergy website https://saveonenergy.ca/Consumer.aspx.

In Market Date: June, 2011



RESIDENTIAL DEMAND RESPONSE PROGRAM (Schedule B-3)

Target Customer Type(s): Residential and Small Commercial Customers

Initiative Frequency: Year round

Objective: The objectives of this Initiative are to enhance the reliability of the IESO-controlled grid by accessing and aggregating specified residential and small commercial end uses for the purpose of load reduction, increasing consumer awareness of the importance of reducing summer demand and providing consumers their current electricity consumption and associated costs.

Description: In *peaksaver* PLUS® participants are eligible to receive a free programmable thermostat or switch, including installation. Participants also receive access to price and real-time consumption information on an In Home Display (IHD).

Targeted End Uses: central air conditioning, electric hot water heaters and pool pumps

Delivery: LDC's recruit customers and procure technology

Additional detail is available:

- Schedule B-1, Exhibit C. Available on IESO's extranet;
- saveONenergy website https://saveonenergy.ca/Consumer.aspx.

In Market Date: May 15, 2014

C&I Program

EFFICIENCY: EQUIPMENT REPLACEMENT INCENTIVE (ERII) (Schedule C-2)

Target Customer Type(s): Commercial, Institutional, Agricultural and Industrial Customers

Initiative Frequency: Year round

Objective: The objective of this Initiative is to offer incentives to non-residential distribution customers to achieve reductions in electricity demand and consumption by upgrading to more energy efficient equipment for lighting, space cooling, ventilation and other measures.

Description: The Equipment Replacement Incentive Initiative (ERII) offers financial incentives to customers for the upgrade of existing equipment to energy efficient equipment. Upgrade projects can be classified into either: 1) prescriptive projects where prescribed measures replace associated required base case equipment; 2) engineered projects where energy and demand savings and incentives are calculated for associated measures; or 3) custom projects for other energy efficiency upgrades.

Targeted End Uses: lighting, space cooling, ventilation and other measures

Delivery: LDC delivered.

Additional detail is available:

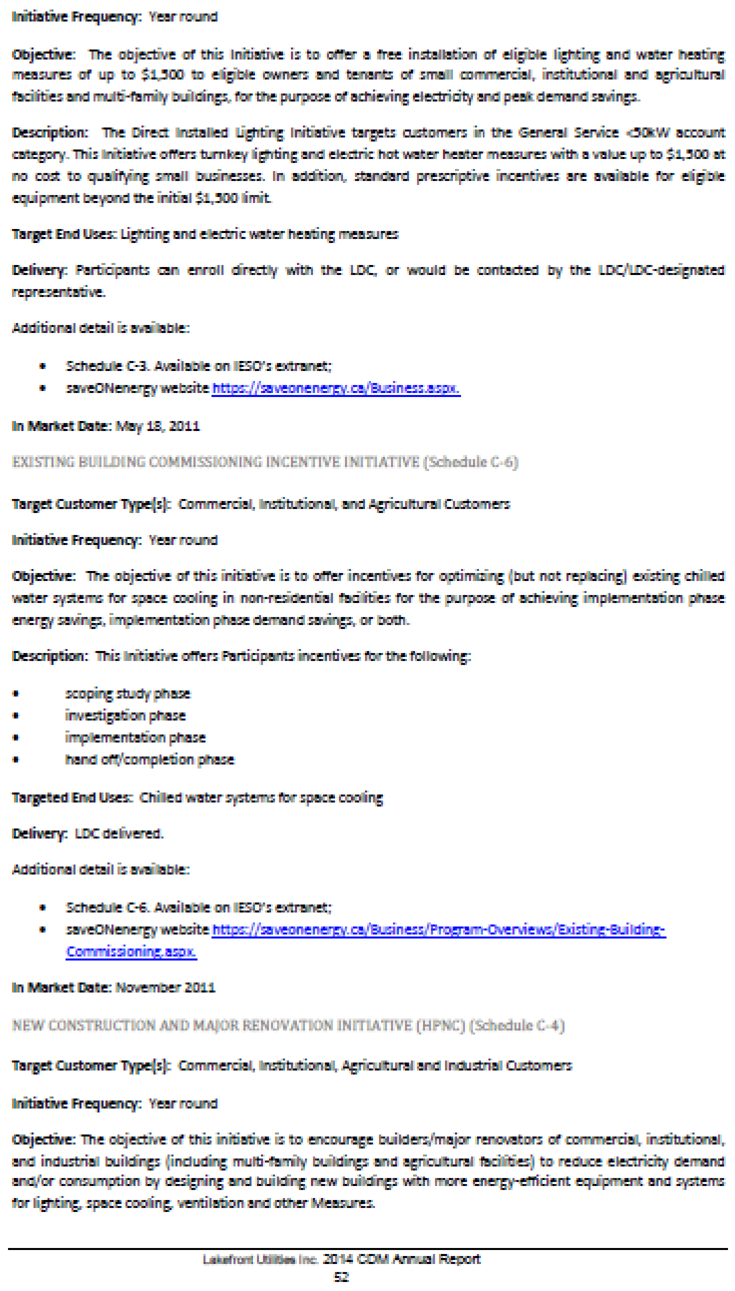
- Schedule C-2. Available on IESO's extranet;
- saveONenergy website https://saveonenergy.ca/Business/Program-Overviews/Retrofit-for-Commercial.aspx.

In Market Date: May 1, 2011

Lessons Learned:

DIRECT INSTALL INITIATIVE (DIL) (Schedule C-3)

Target Customer Type(s): Small Commercial, Institutional, Agricultural facilities and multi-family buildings



Initiative Frequency: Year round

Objective: The objective of this Initiative is to offer a free installation of eligible lighting and water heating measures of up to $1,500 to eligible owners and tenants of small commercial, institutional and agricultural facilities and multi-family buildings, for the purpose of achieving electricity and peak demand savings.

Description: The Direct Installed Lighting Initiative targets customers in the General Service <50kW account category. This Initiative offers turnkey lighting and electric hot water heater measures with a value up to $1,500 at no cost to qualifying small businesses. In addition, standard prescriptive incentives are available for eligible equipment beyond the initial $1,500 limit.

Target End Uses: Lighting and electric water heating measures

Delivery: Participants can enroll directly with the LDC, or would be contacted by the LDC/LDC-designated representative.

Additional detail is available:

- Schedule C-3. Available on IESO's extranet;
- saveONenergy website https://saveonenergy.ca/Business.aspx.

In Market Date: May 18, 2011

EXISTING BUILDING COMMISSIONING INCENTIVE INITIATIVE (Schedule C-6)

Target Customer Type(s): Commercial, Institutional, and Agricultural Customers

Initiative Frequency: Year round

Objective: The objective of this initiative is to offer incentives for optimizing (but not replacing) existing chilled water systems for space cooling in non-residential facilities for the purpose of achieving implementation phase energy savings, implementation phase demand savings, or both.

Description: This Initiative offers Participants incentives for the following:

- scoping study phase
- investigation phase
- implementation phase
- hand off/completion phase

Targeted End Uses: Chilled water systems for space cooling

Delivery: LDC delivered.

Additional detail is available:

- Schedule C-6. Available on IESO's extranet;
- saveONenergy website https://saveonenergy.ca/Business/Program-Overviews/Existing-Building-Commissioning.aspx.

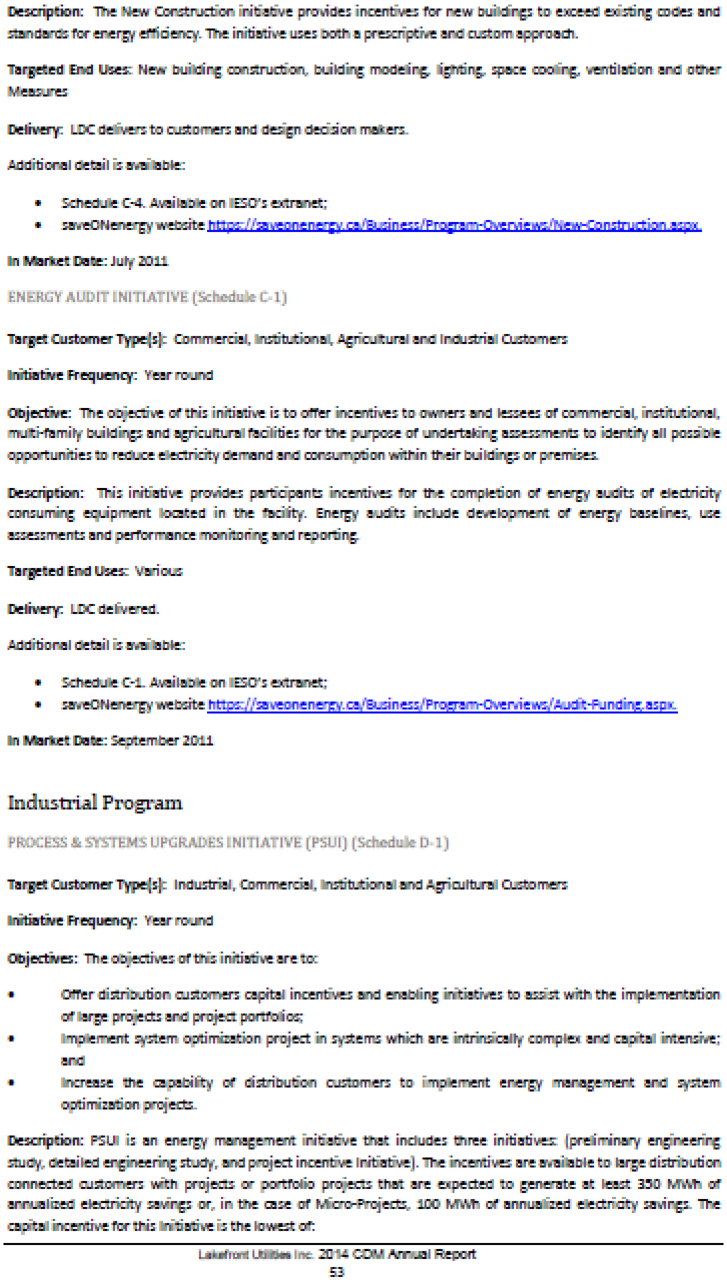
In Market Date: November 2011

NEW CONSTRUCTION AND MAJOR RENOVATION INITIATIVE (HPNC) (Schedule C-4)

Target Customer Type(s): Commercial, Institutional, Agricultural and Industrial Customers

Initiative Frequency: Year round

Objective: The objective of this initiative is to encourage builders/major renovators of commercial, institutional, and industrial buildings (including multi-family buildings and agricultural facilities) to reduce electricity demand and/or consumption by designing and building new buildings with more energy-efficient equipment and systems for lighting, space cooling, ventilation and other Measures.



Description: The New Construction initiative provides incentives for new buildings to exceed existing codes and standards for energy efficiency. The initiative uses both a prescriptive and custom approach.

Targeted End Uses: New building construction, building modeling, lighting, space cooling, ventilation and other Measures

Delivery: LDC delivers to customers and design decision makers.

Additional detail is available:

- Schedule C-4. Available on IESO's extranet;
- saveONenergy website https://saveonenergy.ca/Business/Program-Overviews/New-Construction.aspx.

In Market Date: July 2011

ENERGY AUDIT INITIATIVE (Schedule C-1)

Target Customer Type(s): Commercial, Institutional, Agricultural and Industrial Customers

Initiative Frequency: Year round

Objective: The objective of this initiative is to offer incentives to owners and lessees of commercial, institutional, multi-family buildings and agricultural facilities for the purpose of undertaking assessments to identify all possible opportunities to reduce electricity demand and consumption within their buildings or premises.

Description: This initiative provides participants incentives for the completion of energy audits of electricity consuming equipment located in the facility. Energy audits include development of energy baselines, use assessments and performance monitoring and reporting.

Targeted End Uses: Various

Delivery: LDC delivered.

Additional detail is available:

- Schedule C-1. Available on IESO's extranet;
- saveONenergy website https://saveonenergy.ca/Business/Program-Overviews/Audit-Funding.aspx.

In Market Date: September 2011

Industrial Program

PROCESS & SYSTEMS UPGRADES INITIATIVE (PSUI) (Schedule D-1)

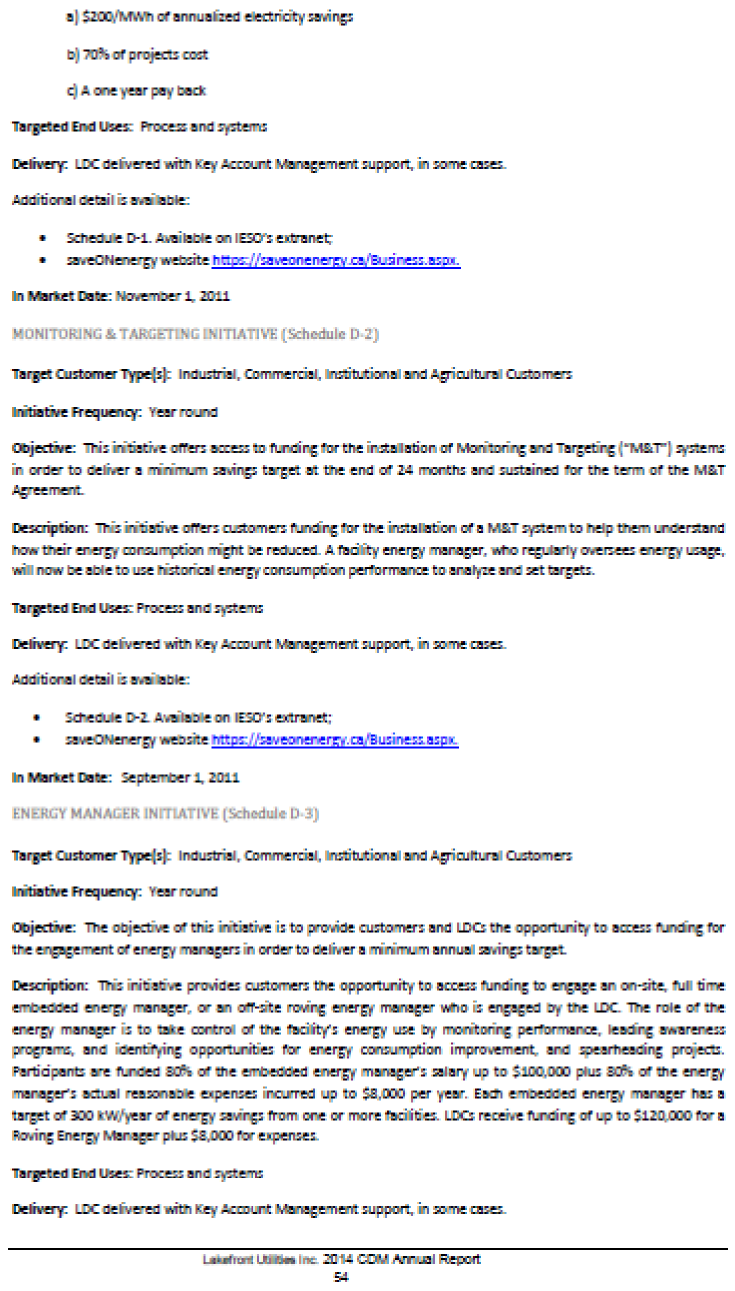
Target Customer Type(s): Industrial, Commercial, Institutional and Agricultural Customers

Initiative Frequency: Year round

Objectives: The objectives of this initiative are to:

- Offer distribution customers capital incentives and enabling initiatives to assist with the implementation of large projects and project portfolios;
- Implement system optimization project in systems which are intrinsically complex and capital intensive; and
- Increase the capability of distribution customers to implement energy management and system optimization projects.

Description: PSUI is an energy management initiative that includes three initiatives: (preliminary engineering study, detailed engineering study, and project incentive Initiative). The incentives are available to large distribution connected customers with projects or portfolio projects that are expected to generate at least 350 MWh of annualized electricity savings or, in the case of Micro-Projects, 100 MWh of annualized electricity savings. The capital incentive for this Initiative is the lowest of:



a) $200/MWh of annualized electricity savings

b) 70% of projects cost

c) A one year pay back

Targeted End Uses: Process and systems

Delivery: LDC delivered with Key Account Management support, in some cases.

Additional detail is available:

- Schedule D-1. Available on IESO's extranet;
- saveONenergy website https://saveonenergy.ca/Business.aspx.

In Market Date: November 1, 2011

MONITORING & TARGETING INITIATIVE (Schedule D-2)

Target Customer Type(s): Industrial, Commercial, Institutional and Agricultural Customers

Initiative Frequency: Year round

Objective: This initiative offers access to funding for the installation of Monitoring and Targeting ("M&T") systems in order to deliver a minimum savings target at the end of 24 months and sustained for the term of the M&T Agreement.

Description: This initiative offers customers funding for the installation of a M&T system to help them understand how their energy consumption might be reduced. A facility energy manager, who regularly oversees energy usage, will now be able to use historical energy consumption performance to analyze and set targets.

Targeted End Uses: Process and systems

Delivery: LDC delivered with Key Account Management support, in some cases.

Additional detail is available:

- Schedule D-2. Available on IESO's extranet;
- saveONenergy website https://saveonenergy.ca/Business.aspx.

In Market Date: September 1, 2011

ENERGY MANAGER INITIATIVE (Schedule D-3)

Target Customer Type(s): Industrial, Commercial, Institutional and Agricultural Customers

Initiative Frequency: Year round

Objective: The objective of this initiative is to provide customers and LDCs the opportunity to access funding for the engagement of energy managers in order to deliver a minimum annual savings target.

Description: This initiative provides customers the opportunity to access funding to engage an on-site, full time embedded energy manager, or an off-site roving energy manager who is engaged by the LDC. The role of the energy manager is to take control of the facility's energy use by monitoring performance, leading awareness programs, and identifying opportunities for energy consumption improvement, and spearheading projects. Participants are funded 80% of the embedded energy manager's salary up to $100,000 plus 80% of the energy manager's actual reasonable expenses incurred up to $8,000 per year. Each embedded energy manager has a target of 300 kW/year of energy savings from one or more facilities. LDCs receive funding of up to $120,000 for a Roving Energy Manager plus $8,000 for expenses.

Targeted End Uses: Process and systems

Delivery: LDC delivered with Key Account Management support, in some cases.

Additional detail is available:

- Schedule D-3. Available on IESO's extranet;
- saveONenergy website https://saveonenergy.ca/Business.aspx.

In Market Date: January 23, 2012

KEY ACCOUNT MANAGER (KAM) (Schedule D-4)

Target Customer Type(s): Industrial, Commercial, Institutional and Agricultural Customers

Initiative Frequency: Year round

Objective: This initiative offers LDCs the opportunity to access funding for the employment of a KAM in order to support them in fulfilling their obligations related to the PSUI.

Description: This initiative provides LDCs the opportunity to utilize a KAM to assist their customers. The KAM is considered to be a key element in assisting the consumer in overcoming traditional barriers related to energy management and help them achieve savings since the KAM can build relationships and become a significant resource of knowledge to the customer.

Targeted End Uses: Process and systems

Delivery: LDC delivered

Additional detail is available:

- ScheduleD-4. Available on IESO's extranet.

In Market Date: LUI did not participate in this initiative.

DEMAND RESPONSE 3 (Schedule D-6)

Target Customer Type(s): Industrial, Commercial, Institutional and Agricultural Customers

Initiative Frequency: Year round

Objective: This initiative provides for Demand Response ("DR") payments to contracted participants to compensate them for reducing their electricity consumption by a pre-defined amount during a DR event.

Description: Demand Response 3 ("DR3") is a demand response initiative for commercial and industrial customers, of 50 kW or greater to reduce the amount of power being used during certain periods of the year. The DR3 Initiative is a contractual resource that is an economic alternative to procurement of new generation capacity. DR3 comes with specific contractual obligations requiring participants to reduce their use of electricity relative to a baseline when called upon. This Initiative makes payments for participants to be on standby and payments for the actual electricity reduction provided during a demand response event. Participants are scheduled to be on standby approximately 1,600 hours per calendar year for possible dispatch of up to 100 hours or 200 hours within that year depending on the contract.

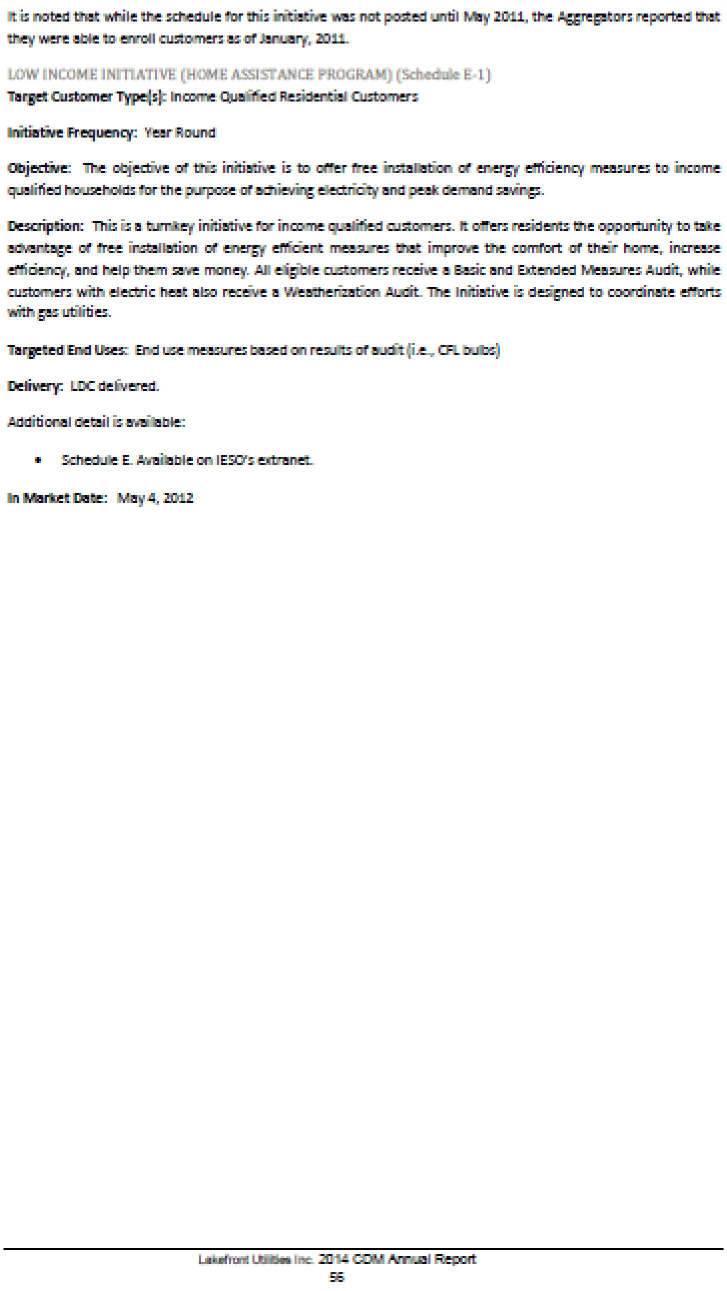
Targeted End Uses: Commercial and Industrial Operations

Delivery: DR3 is delivered by Demand Response Providers ("DRPs"), under contract to the IESO. The IESO administers contracts with all DRPs and Direct Participants (who provide in excess of 5 MW of demand response capacity). IESO provides administration including settlement, measurement and verification, and dispatch. LDCs are responsible for local customer outreach and marketing efforts.

Additional detail is available:

- Schedule D-6. Available on IESO's extranet;
- saveONenergy website https://saveonenergy.ca/Business.aspx

In Market Date: May 1, 2011



It is noted that while the schedule for this initiative was not posted until May 2011, the Aggregators reported that they were able to enroll customers as of January, 2011.

LOW INCOME INITIATIVE (HOME ASSISTANCE PROGRAM) (Schedule E-1)

Target Customer Type(s): Income Qualified Residential Customers

Initiative Frequency: Year Round

Objective: The objective of this initiative is to offer free installation of energy efficiency measures to income qualified households for the purpose of achieving electricity and peak demand savings.

Description: This is a turnkey initiative for income qualified customers. It offers residents the opportunity to take advantage of free installation of energy efficient measures that improve the comfort of their home, increase efficiency, and help them save money. All eligible customers receive a Basic and Extended Measures Audit, while customers with electric heat also receive a Weatherization Audit. The Initiative is designed to coordinate efforts with gas utilities.

Targeted End Uses: End use measures based on results of audit (i.e., CFL bulbs)

Delivery: LDC delivered.

Additional detail is available:

- Schedule E. Available on IESO's extranet.

In Market Date: May 4, 2012

Appendix B: Pre-2011 Programs

ELECTRICITY RETROFIT INCENTIVE PROGRAM

Target Customer Type(s): Commercial, Institutional, and Agricultural Customers

Initiative Frequency: Year Round

Objective: The objective of this initiative is to offer incentives to non-residential distribution customers to achieve reductions in electricity demand and consumption by upgrading to more energy efficient equipment for lighting, space cooling, ventilation and other measures.

Description: The Equipment Replacement Incentive Program (ERIP) offered financial incentives to customers for the upgrade of existing equipment to energy efficient equipment. This program was available in 2010 and allowed customers up to 11 months following Pre-Approval to complete their projects. As a result, a number of projects Pre-Approved in 2010 were not completed and in-service until 2011. The electricity savings associated with these projects are attributed to 2011.

Targeted End Uses: Electricity savings measures

Delivery: LDC Delivered

HIGH PERFORMANCE NEW CONSTRUCTION

Target Customer Type(s): Commercial, Institutional, and Agricultural Customers

Initiative Frequency: Year round

Objective: The High Performance New Construction Initiative provided incentives for new buildings to exceed existing codes and standards for energy efficiency. The Initiative uses both a prescriptive and custom approach and was delivered by Enbridge Gas under contract with the IESO (and subcontracted to Union Gas), which ran until December 2010.

Description: The objective of this initiative is to encourage builders of commercial, institutional, and industrial buildings (including multi-family buildings and agricultural facilities) to reduce electricity demand and/or consumption by designing and building new buildings with more energy-efficient equipment and systems for lighting, space cooling, ventilation and other Measures.

Targeted End Uses: New building construction, building modeling, lighting, space cooling, ventilation and other measures

Delivery: Through Enbridge Gas (and subcontracted to Union Gas)

TORONTO COMPREHENSIVE INITIATIVE

Target Customer Type(s): Commercial and Institutional Customers

Initiative Frequency: Year round

N/A

MULTIFAMILY ENERGY EFFICIENCY REBATES

Target Customer Type(s): Residential Multi-unit buildings

Initiative Frequency: Year round

Objective: Improve energy efficiency of Multi-unit building

Description: IESO's Multifamily Energy Efficiency Rebates (MEER) Initiative applies to multifamily buildings of six units or more, including rental buildings, condominiums, and assisted social housing. The IESO contracted with

GreenSaver to deliver the MEER Initiative outside of the Toronto Hydro service territory. Activities delivered in Toronto were contracted with the City of Toronto.

Similar to ERII and ERIP, MEER provides financial incentives for prescriptive and custom measures, but also funds resident education. Unlike ERII, where incentives are paid by the LDC, all incentives through MEER are paid through the contracted partner (i.e. GreenSaver).

Targeted End Uses: Electricity saving measures

Delivery: IESO contracted with Greensaver

DATA CENTRE INCENTIVE PROGRAM

Target Customer Type(s): N/A

Initiative Frequency: Year round

Objective: N/A

Description: This Initiative is specific to Powerstream's Service Area.

Targeted End Uses: N/A

Delivery: LUI did not participate in this initiative.

ENWIN GREEN SUITES

Target Customer Type(s): N/A

Initiative Frequency: Year round

Objective: N/A

Description: This Initiative is specific to EnWin's Service Area.

Targeted End Uses: N/A

Delivery: LUI did not participate in this initiative.