Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

Commission de l'énergie de l'Ontario
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone: 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

Ontario

BY E-MAIL

July 11, 2016

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Lakefront Utilities Inc. (Lakefront Utilities)
2017 Distribution Rate Application
OEB Staff Interrogatories
OEB File No. EB-2016-0089

In accordance with Procedural Order No. 1, please find attached OEB staff's interrogatories in the above noted proceeding. Lakefront Utilities and all intervenors have been copied on this filing.

Lakefront Utilities' responses to interrogatories are due by August 5, 2016.

Yours truly,

Original Signed By

Georgette Vlahos
Advisor – Electricity Rates & Accounting

Attach.

OEB Staff Interrogatories
2017 Cost of Service Rate Application
Lakefront Utilities Inc. (Lakefront Utilities)
EB-2016-0089
July 11, 2016

Exhibit 1 – Administration

1-Staff-1
Customer Engagement
Ref: Chapter 2 of the Filing Requirements, Section 2.4.3

Chapter 2 of the Filing Requirements states, “The RRFE Report contemplates enhanced engagement between distributors and their customers to provide better alignment between distributor operational plans and customer needs and expectations.” (Emphasis added)

Please describe the differences between customer engagement conducted in preparation for the current application and previous customer engagement.

1-Staff-2
Reflecting Customer Needs
Ref: Chapter 2 of the Filing Requirements

Chapter 2 of the Filing Requirements states, “Distributors should specifically discuss in the application how they informed their customers on the proposals being considered for inclusion in the application, and the value of those proposals to customers (i.e. costs, benefits and the impact on rates). The application should discuss any feedback provided by customers and how this feedback shaped the final application”.

What forms of outreach were employed to explain how the current application serves the needs and expectations of customers? If none were employed, please explain why.

1-Staff-3
Corporate and Utility Organization Structure
Ref: Ex.1/Tab 2/Sch.2

At the above reference it is stated that, historically, Lakefront Utilities had three other subsidiary companies: Lakefront Generation Inc. (LGI), Lakefront Lighting Inc. (LLI) and Cobourg Networks Inc. (CNI). In search of further efficiencies by Lakefront Utilities' parent company (the Town of Cobourg Holdings Inc. (Holdco)), effective January 1, 2013, Lakefront Generation Inc. was amalgamated into Lakefront Utilities Services Inc. (LUSI) and effective January 1, 2015 Lakefront Lighting Inc. was amalgamated into Cobourg Networks Inc. Following these amalgamations, CNI was amalgamated into LUSI effective January 1, 2016.

(a) Please describe if there have been any changes with respect to the allocation of administrative services due to the corporate restructuring.

(b) Please describe the nature of the efficiencies realized by Lakefront Utilities' parent company as a result of these amalgamations.

1-Staff-4
Ref 1: Ex.1/Tab 4/Sch. 5 - Overview of Operation Maintenance and Administrative Costs - LEAP Funding
Ref 2: 2012 Cost of Service Application (EB-2011-0250) – Staff IRR 4

At reference 2, Lakefront Utilities noted that it included an amount of $6,160 into its actual budgeted expenses for LEAP in its 2012 cost of service application.

At reference 1, the table below (in the current application) shows that the amount approved by the OEB is $5,000. Please reconcile the apparent discrepancy.

	Board Approved	2017	Variance $	Variance %
Operations	724,871	525,404	(199,467)	-27.52%
Maintenance	322,942	195,787	(127,156)	-39.37%
Billing and Collecting	412,387	566,316	153,929	37.33%
Community Relations	6,824	20,219	13,395	196.29%
Administrative and General	1,056,309	1,048,304	(8,005)	-0.76%
Taxes other than Income Taxes	40,837	62,359	21,523	52.70%
Sub-account LEAP Funding	5,000	5,850	850	16.99%
Total	**2,569,170**	**2,424,239**	**(144,931)**	**-5.64%**

1-Staff-5
Customer Satisfaction Survey
Ref: Ex.1/Tab 5/Sch.2

Lakefront Utilities developed its own survey after concluding that using a third party would lead to prohibitive costs. Lakefront Utilities indicates that it received 243 responses to its survey.

(a) Does Lakefront Utilities find the response rates acceptable as a basis for measuring customer satisfaction? If so, why?

(b) How much weight did Lakefront Utilities give to the identified customer preferences in setting priorities for investment?

(c) What steps does Lakefront Utilities intend to undertake to improve the information regarding customer views of Lakefront Utilities' performance. In your response, please address actions taken for commercial customers as well as other customers.
(d) Please file a copy of the Customer Satisfaction Survey.

Exhibit 2 – Rate Base

2-Staff-6
Ref: Ex.2/Tab 1/Sch.2

Lakefront Utilities' rate base for the 2017 test year is forecast to increase by approximately 11.9% from 2012 OEB-approved.
(a) In its annual capital planning and implementation for the years 2012 to 2016, did Lakefront Utilities take into account the cumulative impact its capital expenditures would have on rate base and rates in 2017?
(b) How did this inform the pacing of investments identified in the Distribution System Plan for 2017 forward?

2-Staff-7
Ref: Table 2-16 – Capital Projects Table – 2012-2017
Ref: Ex.2/Tab 5/Sch.3 – Capital Expenditures

In Table 2-16, Lakefront Utilities has provided a list of 2017 capital projects. The total Test Year 2017 capital expenditure for all projects is $1,699,590.
(a) Are all of the projects and related capital expenditures of $1,699,590 that are listed in Table 2-16 expected to be placed in-service in 2017 and to be added to the 2017 Rate Base?
(b) If some of the projects that are listed in Table 2-16 are not expected to be in-service in 2017 and as a result will not be added to the 2017 Rate Base, please identify all such projects, the associated capital expenditure and the expected in-service date.

2-Staff-8
Ref: DSP, Section 4.1.3. (5.4.1c) Effect of Planning on Capital Expenditures, Pages 115-116
Ref: Chapter 2 Appendices, Tab 2-AA – Capital Projects

Projects	2012	2013	2014	2015	2016 Bridge	2017 Test
System Access	1,988,426	209,120	93,130	138,601	85,000	126,500
System Renewal	843,944	314,790	827,909	722,176	888,800	1,183,450
System Service	694,888	79,788	308,356	662,152	392,000	314,640
General Plant	868,700	285,870	200,709	257,651	327,000	75,000
Total	**4,395,958**	**889,568**	**1,430,104**	**1,780,580**	**1,692,800**	**1,699,590**

As seen in the table above, capital expenditures for the past 5 years have varied. Lakefront Utilities' capital plan includes the planned expenditures for voltage conversion of $1.5 million in Cobourg through the forecast period. In Colborne, feeder and station rebuilds will continue through the forecast period with planned expenditures of $2.9 million.

(a) Please describe and quantify where possible the benefits that the applicant's customers will realize from this investment.

(b) Please describe the alternatives to capital investment that were assessed and rejected in favour of the proposed capital investment.

2-Staff-9

Ref: Chapter 2 Appendices, Tab 2-AB – Capital Expenditures

Please confirm if any of the projects listed at the above reference were planned and prioritized based on climate change expectations. If yes, please provide supporting rationale.

2-Staff-10

Rate-Funded Activities to Defer Distribution Infrastructure

On December 19, 2014 the OEB issued the *Conservation and Demand Management (CDM) Requirement Guidelines for Electricity Distributors* (EB-2014-0278) (the 2015 CDM Guidelines). Section 4.1 of the 2015 CDM Guidelines outlines the OEB's guidance in support of the Government's objective of putting conservation first in infrastructure planning. The OEB established a policy that allows electricity distributors to seek distribution rate funding for CDM programs and other initiatives for the purposes of avoiding or deferring future infrastructure projects.

(a) Please describe if Lakefront Utilities has considered incremental conservation initiatives, over and above those established in cooperation with the IESO, in order to defer or avoid future infrastructure projects as part of its distribution system planning processes.
(b) If the answer to (a) is yes, please describe how.

2-Staff-11

Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, Sources of Cost Savings, p. 76, 3.1. (5.3.1) Asset Management Process Overview, p. 88, Figure 5

On page 76, it is noted that *"LUI Distribution System Plan cost savings are expected to be achieved through the following:*

- *Asset Condition Inspections and comprehensive data collection will provide a better understanding of each asset's stage in their lifecycle which will lead to more cost effective decisions with respect to maintenance, refurbishment and replacement decisions.*
- *Proactive maintenance and replacement of plant will reduce reactive maintenance costs and improve service to the customer that will result in fewer and shorter duration outages that will have a beneficial impact on the cost of outages to customers. A structured program will also smooth out financial rate impacts in an effort to avoid disruptive rate spikes to address the volume of plant reaching end of life.*
- *Improved use of the GIS to capture/access plant attribute data (i.e. nameplate data, condition, inspection/maintenance histories, etc.) will aid in cost control through optimization of the asset's lifecycle.*
- *Prudent investment in distribution automation (i.e.. remotely operated switches), as part of Smart Grid development, will improve day to day switching operations and have a positive impact on improving outage restoration times thereby mitigating customer outage costs."*

(a) Please identify specific dollar savings in reduction of reactive maintenance costs for each of the years from 2017-2021 and beyond 2021 due to proactive maintenance and replacement of the plant.
(b) Please identify specific SAIFI/SAIDI improvements (or customers interrupted CI/customer hours interrupted (CHI)) for each of the years 2017-2021 and beyond 2021 due to proactive maintenance and replacement of the plant.

(c) Please identify specific SAIFI/SAIDI improvements (or CI/CHI) for each of the years 2017-2021 and beyond 2021 due to prudent investment in distribution automation.

(d) Please identify any other specific cost savings and SAIFI/SAIDI improvements (or CI/CHI) for each of the years 2017-2021 and beyond 2021 that are expected to be achieved due to any of the initiatives or capital projects that have been implemented or going to be implemented in accordance with the Distribution System Plan.

On p. 88, LUI states that Reliability Projection is one of the elements of the Decision Support Box that is used for planning purposes.

(e) Please show overall Reliability Projections (SAIFI/SAIDI or CI/CHI for 2017-2021) as a result of the proposed Distribution System Plan.

2-Staff-12

Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, 2.4. (5.2.3) Performance Measurement for Continuous Improvement, 2.4.1. (5.2.3a) Metrics Used to Monitor Distribution System Planning Performance p. 80

In addition to the OEB Scorecard measures, Lakefront Utilities doesn't propose any DSP measures in any of the performance categories outlined in the Section 5.2.3, *Chapter 5 of the Ontario Energy Board's (OEB) Filing Requirements for Electricity Transmission and Distribution Applications*, such as customer-oriented performance, cost efficiency/effectiveness of planning and implementation, and asset/system orientation performance. If available, please provide a description of any additional measures with formulae, historical actuals and targets in 2017-2021.

2-Staff-13

Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, 2.4. (5.2.3) Performance Measurement for Continuous Improvement, 2.4.2. (5.2.3b) Summary of Performance Trends, p. 81

Please identify the source for the industry data provided in the reference above and the utilities included in the dataset.

2-Staff-14
Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, 2.4.2. (5.2.3b) Summary of Performance Trends, p. 82

On page 82 Lakefront Utilities states: *Lakefront Utilities collects and reports outage data using the standard format and codes specified in the RRR document. The data is transferred to an excel spreadsheet for ease of producing standard and custom reliability reports. Calculations are made to determine the reliability indices SAIDI, SAIFI, and CAIDI. The data are also sorted to determine frequency and duration for each individual feeder, and also sorted to determine cause and affected components.*

(a) Please provide in Excel spreadsheet format the CI/CHI data for each individual feeder, for each year from 2011-2015, by cause, excluding the 2013 Ice Storm impact.
(b) Please provide the number of unplanned replacements/failed assets for each major asset class for each year 2011-2015.

2-Staff-15
Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, 2.4.2. (5.2.3b) Summary of Performance Trends, Outage Causes, pp. 83-84, Figures 3-4

In figures 3 and 4 on pp. 83-84, Lakefront Utilities has provided breakdowns of customer interruptions (CI) and customer-hours interrupted (CHI).

(a) Can Lakefront Utilities provide the total % of interruptions by OEB cause code over the period of 2011-2015 in the table format below?
(b) Can Lakefront Utilities provide the total % of interruptions by OEB cause code over the period of 2011-2015 in the table format shown below?

OEB Cause Code	2011	2012	2013	2014	2015
0					
1					
2					
3					
4					
5					

6					
7					
8					
9					

2-Staff-16
Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, 3.1.3. Asset Management Strategy, pp. 90-91

On page 90, table 7, Lakefront Utilities provides criteria for the measurement of success of the Asset Management Strategy. Can Lakefront Utilities provide its respective performance over the historical period 2011-2015 in the format below?

	2011	2012	2013	2014	2015
Lost/non-lost time injuries					
ESA Non-compliance					
Customer Survey Response					
Investment Spending					
Investment Scheduling					
Reportable spills in the MOE					

2-Staff-17
Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, 3.1.4. Asset Management Plan (AMP), p. 91

Please submit the Asset Management Plan mentioned in the above reference.

2-Staff-18

Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, 3.2.1. Discretionary Capital Projects, p. 94

On page 94, Lakefront Utilities states:

LUI is utilizing a product call the Optimizer that was created by the UMS Group and marketed by the ERTH Corporation.

(a) Please confirm that the Optimizer was used for all the projects identified in the DSP for 2016-2021 years.

(b) Please provide a prioritization score for each of the Material Projects in the DSP. Please provide prioritization scores broken down by each of the criteria and a summary score for the project.

2-Staff-19

Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, 3.2.1. Discretionary Capital Projects, p. 95

On page 95, Lakefront Utilities states:

Service Quality: *considers to what extent the project impacts the power system reliability and customer service. If it will definitely eliminate a sustained feeder outage, the economic benefit can be determined.*

Please provide a description and values used for a determination of the economic benefit of the project that aims to eliminate a sustained feeder outage.

2-Staff-20

Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, 3.2.6. Asset Condition Assessment (ACA), p. 100

With respect to asset condition assessment, Lakefront Utilities provided in Appendix E, for Colborne service area, a detailed assessment only for poles.

(a) Please provide any other reports that have been completed or drafted in relation to ACA of any other distribution assets.

(b) Please explain how the results of the ACA for the Colborne area were used to develop the DSP and specific 2016-2021 projects.

2-Staff-21

Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, 3.3.3. Stations, p. 104, Table 10, 3.3.4. Overhead Asset Details, p. 105, Table 11

(a) In relation to Table 10, please provide the quantity of each of the asset classes in the system and respective strategy (similar to table 11 on the same page).
(b) In relation to Table 11, please describe the strategy in more detail for each of the asset classes, specifically, what thresholds or criteria are used to determine whether the asset needs to be replaced.
(c) Please provide Lakefront Utilities' understanding or definition of useful life.

2-Staff-22

Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, 3.3.3. Stations, p. 104, Victoria Station Rebuild, pp. 160-163, Durham Station Rebuild, pp. 190-193

On page 36, Lakefront Utilities states:

Substation power transformers aren't usually proactively replaced based solely on their age. Other factors such as power transformer condition (i.e. degree of corrosion, evidence of leaking gaskets), transformer loading, insulating oil condition and the impact of an unplanned transformer failure are also considered.

(a) Can Lakefront Utilities provide the detail of condition assessment or any other testing/inspection condition evidence for substation transformers that are planned to be replaced in 2016-2021 at Victoria and Durham stations?
(b) Can Lakefront Utilities provide the detail of condition assessment or any other testing/inspection condition evidence for oil circuit breakers that are planned to be replaced in 2016-2021 at Victoria and Durham stations?
(c) Please provide a timeframe when the Colborne 4kV system is planned to be converted to 27.6kV.

2-Staff-23

Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, 3.3.4. Overhead Asset Details, Poles, pp. 105-106, Appendix E Colborne Asset Condition Assessment

(a) Please confirm the total number of poles in the Colborne service area assessed in the scope of this report.
(b) Please identify the number of poles in the Colborne service area ACA report that did not have age information available.
(c) Please provide a description/definition of each of the degradation factor scores from 0 to 5 used within the pole health index (HI).
(d) Please provide a total contribution of the age factor for a 40+ year old pole into the max HI.
(e) Please provide the total quantity of poles within the age ranges from 40-50, 50-60, 60-70 and 70+ years respectively. Please provide a number of poles in poor condition for each of the specified age ranges.
(f) Please provide any details on whether inspection tests other than that of visual tests, have been performed on the poles (e.g. sound, probe, drill, etc.) Please provide the results of these tests if available.
(g) The report states: *Replacing approximately 500 poles in the next ten years will help to provide consistency in the amount of investment required in this category thereby avoiding a lumpy investment program.* Please confirm that the report recommends replacing approximately 500 poles in the next ten years in the Colborne service area.

2-Staff-24
Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan

(a) Please provide asset demographics data for all the major distribution asset classes, including substation equipment (e.g. overhead poles, transformers, and switches; underground cables, transformers, and switches; substation transformers, breakers, etc.).
(b) Please provide unit cost assumptions used as a basis to form 2016-2021 project estimates.
(c) For each of the 2016-2021 material projects in system renewal and system service category (excluding IT projects and Capacity Planning), please provide a count of new assets to be installed in the project, by asset class. Please fill out the table below (adjust the table if required).

Material Project Name	Number of new assets to be installed					
	Poles	Transformers	Switches	Cables (m)	Power Transformer	Circuit Breaker

(d) For all 2016-2021 material projects in system renewal and system service category (excluding IT projects and Capacity Planning), please provide asset age and condition assessment information as outlined in the table below (adjust the table if required).

Asset Class	Total number of assets to be removed	Number of assets 30-40 years old	Number of assets 40-50 years old	Number of assets 50-60 years old	Number of assets 60+ years old	Number of assets in Poor condition	Number of assets in Very Poor condition
Poles							
Overhead transformers							
Overhead switches							
Cables (m)							
Underground transformers							
Underground Switches							
Power transformers							
Circuit breakers							

2-Staff-25

Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, 4.1.6. (5.4.1f) Customer Engagement Activities, p. 123, 4.2.4. (5.4.2d) Customer Engagement, p. 131

Please identify what specific changes were made to the filed Distribution System Plan based upon the customer survey performed by Innovative Research Group and completed in April 2016.

2-Staff-26

Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, Infrastructure Renewal Projects - 44kV/28kV Feeders ROW Rebuild, p. 129, 44kV/28kV ROW – D'Arcy to Brook, pp. 206-208, 44kV/28kV ROW – Division to D'Arcy, pp. 247-249, 44kV/28kV ROW – Ontario to Division, pp. 273-275, 44kV/28kV ROW – Burnham to Ontario, pp. 298-300, Appendix G 44kV system Capacity Study. pp. 496-501

In total, Lakefront Utilities is planning to spend approximately $1,087,350 on four 44kV/28kV stations from ROW Burnham to Brook.

(a) Please confirm that that there are no other projects that aim to rebuild these 44kV/28kV feeders.
(b) Please provide reliability data for these feeders, CI/CHI, for each year 2011-2015, excluding 2013 Ice Storm impact.
(c) Please provide a reliability forecast (CI/CHI) for 2017-2021 if these projects are to be postponed beyond 2021.
(d) Please provide asset condition assessment for all major assets that are planned to be removed within these projects.
(e) Please provide any details on whether inspection tests, other than visual tests have been performed on the poles on these feeders (e.g. sound, probe, drill, etc.) Please provide the results of these tests if available.
(f) Please confirm that 44kV System Capacity Study doesn't recommend to rebuild these circuits to 556 ASC.

2-Staff-27

Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, 4.2.1. (5.4.2a) Capital Objectives – Criteria and Assumptions, p. 129

For each of the vehicles that are planned to be replaced in 2016-2021, please provide:

(a) Current mileage.
(b) Estimated mileage at the time of replacement.
(c) Current maintenance costs.

2-Staff-28

Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, 5.4.1. (5.4.5.1a) Comparative Expenditures by Category, Figure 20, p. 139

Please confirm that inflation is included in the capital cost estimates for the years from 2017-2021.

2-Staff-29

Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, 5.4.1. (5.4.5.1b) Impact of System Investments on O&M, Table 29, p. 142

(a) Please provide comparable O&M costs for each of the historical and bridge years from 2012-2016.
(b) Please provide a basis for O&M projections by spending category that adds up to $721,191 in 2017.
(c) Please provide a basis for O&M increase for 2018-2021.
(d) Please identify how many new net plant additions are going to be added to the system for each year from 2016-2021.
(e) Please identify an average annual O&M cost for Kerr 4kV MS in 2012-2016. If a specific number is not available, please identify total O&M spending on all substations owned by Lakefront Utilities.

2-Staff-30

Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, 5.4.1. (5.4.5.1a) Comparative Expenditures by Category, Table 27, p. 141, GIS (Geospatial Information Systems), pp. 173-174, OMS (Outage Management System) – Phase I, pp. 240-241, OMS (Outage Management System) – Phase II, pp. 266-267

(a) Please provide the basis for capitalizing data collection and data update projects (GIS and OMS Phase I) related to GIS and OMS.

(b) Please explain the rationale to include IT-system investment in GIS and OMS into the System Service investment category, considering that this category covers the investments and modifications to the distribution system only.

2-Staff-31
Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, 2016 Material Projects, Project Name New Services, p. 148

Please show historical spending for new services for each year in the 2012-2015 period.

2-Staff-32
Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, 27.6kV Increased Capacity Planning, p. 296

Please provide the basis to include this capacity planning study into the capital spending amounts (i.e. to capitalize the study).

2-Staff-33
Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, Brook Rd Stn – 44kV Termination Pole and Cables, pp. 288-290

On page 289, Lakefront Utilities states:

The primary drivers for this project are the replacement of existing underground 44kV main primary supply (cables and termination pole) to Brook Rd Substation. This replacement is required to allow use of full capacity of the recently replaced Station transformer due to increased loading from 4kV Voltage Conversion projects. The requirement to upgrade this conductor is detailed in 4kV Voltage Conversion Plan.

On page 290, Lakefront Utilities states:

In 1996, Brook Rd Substation capacity was 15MVA as per design. In 2014, Brook Rd Station transformer experienced a catastrophic failure due to water ingress. With the planned 4kV voltage conversion plan in mind, it was determined that increased station transformer capacity would be required. As the insurance company was compensating LUI for the loss of the transformer, LUI decided to pay the incremental costs to upgrade this unit to 20/26/32 MVA. This new transformer now has approximately double the *capacity of the previous failed unit. The existing 44kV primary cables are sufficient for up to 26MVA capacity of the station transformer. Peak loading on Victoria St Substation reached as high as 18MVA during the period Brook St Station was out of service. With the planned shift of approximately 12 MVA peak loading of remaining 4kV assets to the 27.6kV system, we expect we will require the full second stage fan rating of 32MVA for contingency purposes.*

(a) What peak loads are planned to be shifted from 4kV system to the 27.6kV system by the end of 2021 in this area?
(b) What is the estimated reliability risk to the system (expected CI/CHI) if this project is to be postponed beyond 2021?

2-Staff-34

Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, Appendix F, 4kV Voltage Conversion Plan, pp. 490-495

(a) Has Lakefront Utilities completed a financial cost/benefit lifecycle analysis of the conversion plan? If yes, please provide the analysis.
(b) Has Lakefront Utilities completed a reliability analysis of a 4kV system and reliability improvements that could be expected from conversion of the system to 27.6kV? If yes, please provide the analysis.
(c) What is a bare minimum of projects (from the list of 2016-2021 material projects) that are required to be completed to remove Kerr MS from service in 2018?
(d) What is an estimated reliability impact (CI/CHI) in 2017-2021 if the conversion projects are to be postponed beyond 2021?
(e) Does Lakefront Utilities own the land used for Kerr MS? If yes, is Lakefront Utilities planning to sell the land once Kerr MS is taken out of service? What is the estimated dollar value that Lakefront Utilities is planning to receive by selling the land?

2-Staff-35

Ref: Exhibit 2, Attachment A – Lakefront Utilities Inc., Distribution System Plan, SF6 Padmount Switchgear, pp. 194-196, Appendix F, 4kV Voltage Conversion Plan, pp. 490-495

Lakefront Utilities is planning to replace switchgear PMH-4, PMH-5, and PMH-6 in the area.

(a) Please provide age information for each of the switchgears.

(b) Please confirm that all three switchgears were recommended to be replaced in 4kV Voltage Conversion Plan.
(c) Please explain in detail why a “replacement of this equipment is required to proceed with the conversion of the Cobourg downtown and waterfront from 4kV to 27.6kV”.
(d) Please confirm that if all or any of these three switchgears is not replaced than conversion from 4kV to 27.6kV can’t be performed.

Exhibit 3 – Operating Revenue

3-Staff-36
Ref 1: Load Forecast Model, Tab 11 - Final Load Forecast
Ref 2: Chapter 2 Appendices, Tab 2-IA_Act_Frcst_Data

(a) Please update Tab 10 of the Load Forecast Model to include 2016 year to date actuals and provide 2015 actual data for the comparable time frame.
(b) Please compare the 2016 actuals to date with the same period data for 2015.
(c) Please compare actual data to forecasted data and explain any material variances.

3-Staff-37
Ref 1: E3/Tab 1/Sch.4 – Overview of Load Forecast Methodology, Page 6
Ref 2: E3/Tab 1/Sch.12 – Determination of Weather Normalized Forecast, Page 24

At reference 1, Lakefront Utilities notes that it currently does not have a process to adjust weather actual data to a weather normal basis since it is Lakefront Utilities’ understanding there is not an OEB approved method to weather normalize actual data.

At reference 2, Lakefront Utilities states “Weather normalized wholesale kWh, for historical years, are allocated to these classes based on these historical shares.”
(a) Please explain the seemingly contradictory statements.
(b) Would Lakefront Utilities agree that if the following was done, it would result in ‘weather normal’ for historical years:
• run the regression model for historical years using all actual dependent variables including HDD and CDD for the actual year.(A)
• run the regression model for historical years using all actual dependent variables except use normal HDD and CDD values.(B)

- Apply the weather normalization factor (B/A) from the above two runs for each year to the actual purchases.

(c) Please provide the results of running the regression model as per the above process.

3-Staff-38
Ref 1: E3/Tab 1/Sch.4 – Overview of Load Forecast Methodology, Page 6, Tables 3.2, 3.3 and 3.4
Ref 2: Chapter 2 Appendices, Tab 2-IA_Act_Frcst_Data

OEB staff notes that the figures in the tables provided at reference 1 do not reconcile to the data entered in reference 2.

Please reconcile the data and provide corrected tables and update the applicable tab in the Chapter 2 Appendices in accordance with interrogatory 6-Staff-54.

Exhibit 4 – Operating Expenses

4-Staff-39
Ref 1: Ex.4/Tab 1/Sch.1 – Overview of Operating Expenses, Table 4.0
Ref 2: Chapter 2 Appendices – Tab 2-JA
Ref 3: Revenue Requirement Workform – Tab Rev_Reqt, Row 15

OEB staff notes that the 2017 total OM&A expenses in the table at the first reference above does not reconcile to the Chapter 2 Appendices filed by Lakefront Utilities. OEB staff notes that the table at reference 1 indicates an amount of $2,424,239 while the Chapter 2 Appendices indicate an amount of $2,432,077. Similarly, both of these figures do not reconcile to the amount indicated in the RRWF in reference 3 (the amount showing is $2,361,880).

(a) Please clarify the correct total OM&A expenses Lakefront Utilities is seeking approval for.

(b) Please make the necessary corrections in the re-filed Excel workforms as applicable.

4-Staff-40
Ref: Chapter 2 Appendices, Tab 2-JA

The proposed OM&A costs in 2017 of $2,432,077 represent an increase of $161,156 or 7.1% over the 2015 actual OM&A.

(a) Please identify any customer engagement relating specifically to the increase in OM&A that supports the increases proposed in this application.
(b) Further, how has the Applicant communicated these benefits to its customers, and how did customers respond? Please provide some examples, including any customer feedback. If no communications took place, please explain why not.
(c) Please identify what, if any, improvements in services and outcomes the applicant's customers will experience in 2017 and during the subsequent IRM term as a result of increasing the provision for OM&A at the rate indicated.
(d) Please identify any initiatives considered and/or undertaken by Lakefront Utilities, including any analysis conducted, to optimize plans and activities from a cost perspective.

4-Staff-41
Ref: Ex.4/Tab 2/Sch. 1 – Cost Drivers Table, Page 13

Lakefront Utilities' bad debt expense shows a jump of $104k in the 2014 column of Lakefront Utilities' OM&A drivers cost table. Lakefront Utilities notes its bad debt expenses increased in 2014 due to an increase in customers paying late and the fact that Lakefront Utilities had previously not been consistent with writing off bad debts.

(a) Please explain further how Lakefront Utilities was not consistent in writing off bad debts and what impact this had on its records and its financial position.
(b) How do Lakefront Utilities' actual bad debt expense costs for 2016 compare to 2014?

4-Staff-42
Ref: Ex.4/Tab 3/Sch.1 – Program Description, Page 21

At the above reference, Lakefront Utilities notes that it constantly searches ways to minimize costs and improve efficiencies through collaboration, whether it is with CHEC or neighbouring utilities.

(a) What are the annual fixed and variable costs of Lakefront Utilities' membership in CHEC in 2017?
(b) Has the membership led to any offsetting efficiency gains?
    i. If so, please describe how the savings have been incorporated into Lakefront Utilities' operating budget.
    ii. If not, please explain why not.

4-Staff-43

As part of its application, Lakefront Utilities filed the results of a Utility Pulse survey of customers to support Lakefront Utilities' DSP. The Utility Pulse report contained data comparisons where applicable to an Ontario-wide LDC benchmark and to Ontario LDCs participating in Utility Pulse's customer satisfaction survey.

Did Lakefront Utilities conduct any benchmarking other than the above to support the current cost of service application?

4-Staff-44
Ref: E4/Tab 2/Sch.2 – OM&A Variance Analysis, Page 10, Table 4.1

Please provide the most recent actuals in the same level of detail as table 4.1 of the above noted reference.

4-Staff-45
Ref: E4/Tab 3/Sch.2 – OM&A Variance Analysis, Page 12

At the above reference, Lakefront Utilities notes that it terminated a full time staff employment in 2013 that was dedicated to IT and hired a subcontractor.

(a) Please explain why the decision was made to hire a subcontractor as opposed to a dedicated FTE.
(b) Did Lakefront Utilities preform a cost analysis for this decision, if so, please provide the documentation.

4-Staff-46
OPEBs

Lakefront Utilities has recovered OPEBs in rates previously.

(a) Please indicate if OPEBs were recovered on a cash or accrual accounting basis for each year since Lakefront Utilities started to recover OPEBs.
(b) Please complete the table below to show how much more than the actual cash benefit payments, if any, have been recovered from ratepayers from the year Lakefront Utilities started recovering amounts for OPEBs.

OPEBs	First year of recovery to 2011	2012	2013	2014	2015	2016	2017	Total
Amounts included in rates								
OM&A								
Capital								
Sub-total								
Paid benefit amounts								
Net excess amount included in rates greater than amounts actually paid								

(c) Please describe what Lakefront Utilities has done with any recoveries in excess of cash benefit payments.

4-Staff-47
Ref: Ex.4/Tab 3/Sch. 7 - Purchases of Non-Affiliate Services

At the above reference, Lakefront Utilities outlines its procurement process when purchasing services. Please provide a copy of Lakefront Utilities' procurement policy, including information on such areas as the level of signing authority, a description of its competitive tendering process and confirmation that its non-affiliate services purchases are in compliance with it.

4-Staff-48
Ref: Ex.4/Tab 3/Sch. 9 - Regulatory Costs
Ref: Chapter 2 Appendices – Tab 2-M

Lakefront Utilities notes that it did not include any costs related to a settlement conference and/or oral hearing as part of this application. Lakefront Utilities notes that as an effort to keep OM&A costs to a minimum, it wishes to proceed by way of written hearing. However, if the OEB required Lakefront Utilities to go to settlement or oral hearing, the utility reserves the right to increase its regulatory costs accordingly.
OEB staff notes that Lakefront Utilities also did not include any intervenor costs.

In PO1, the OEB has provided parties the opportunity to take part in ADR in an effort to reach a full settlement on all issues.

Please update the forecast of regulatory costs for this application, and provide the information in accordance with IR 6-Staff-54.

4-Staff-49

Ref: Exhibit 4, Attachment D - 2014 Lakefront Utilities CDM Annual Report, Page 28

OEB staff notes that the CDM report filed as Attachment D is not legible in both PDF and hardcopy format. Please provide, specifically page 28, in table format in order to verify the savings used in Lakefront Utilities' LRAMVA calculation.

4-Staff-50

LRAMVA Calculations

Ref: Ex.4/Tab 1/Sch. 2, Table 4.26

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**

It appears as though Lakefront Utilities is seeking approval of lost revenues from 2011 and 2012 programs. OEB staff notes that these amounts were approved in EB-2012-0144 (2011 lost revenues) and EB-2013-0148 (2012 lost revenues).

(a) Please confirm if this was in error.
(b) If the answer to (a) is no, please explain why Lakefront Utilities believes this is appropriate.
(c) Please provide an updated LRAMVA calculation excluding these amounts.

4-Staff-51

LRAMVA Calculations

Ref: EB-2011-0250 Settlement Agreement, Page 21

The table below shows the OEB-approved CDM component in Lakefront Utilities' load forecast from its 2012 cost of service application:

Rate Class	Volume	Unit
Residential	1,049,050	kWh
GS<50kW	504,413	kWh
GS>50kW	2,566	kW

It appears as though in its current application, Lakefront Utilities has not reduced its lost revenues by the approved CDM component in its load forecast in EB-2011-0250.

(a) Please provide an explanation and, if necessary, provide a revised LRAMVA calculation making the necessary corrections.

4-Staff-52
Ref: Ex.4/Tab 6/Sch. 2 – LRAMVA

Please provide a table that lists all the appropriate OPA CDM Initiatives that produced net CDM savings which were used in the LRAMVA calculations. For each rate class, please list all relevant CDM initiatives in the applicable year and provide the subsequent net CDM savings for each. An example is provided below:

Residential	**Net kWh**	**Net kW**
Initiative 1		
Initiative 2		
Initiative 3		
Total		
Volumetric Rate Used		
Lost Revenues		
GS < 50 kW	**Net kWh**	**Net kW**
Initiative 1		
Initiative 2		
Initiative 3		
Total		
Volumetric Rate Used		
Lost Revenues		

GS > 50 kW	Net kWh	Net kW
Initiative 1		
Initiative 2		
Initiative 3		
Total		
Volumetric Rate Used		
Lost Revenues		
Other classes (e.g., Streetlighting, Large Use, etc.), as needed	**Net kWh**	**Net kW**
Initiative 1		
Initiative 2		
Initiative 3		
Total		
Volumetric Rate Used		
Lost Revenues		

A separate table should be provided for each year.

Exhibit 5 – Cost of Capital and Capital Structure

5-Staff-53
Ref 1: Exhibit 5, Appendix 2-OA, Appendix 2-OB
Ref 2: Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB 2009-0084)
Ref 3: OEB Cover Letter and OEB Staff Report on the Review of the Cost of Capital for Ontario's Regulated Utilities, January 14, 2016

In Table 1 on page 3 of Exhibit 5, Lakefront Utilities notes that the requested cost of long-term debt to be recovered as part of its 2017 test year revenue requirement is at a rate of 4.54%. This is also shown in Appendix 2-OA for the 2017 test year, also copied on page 5 of Exhibit 5.

Appendix 2-OB (also shown on page 6 of Exhibit 5) documents the following three actual and forecasted long-term debt instruments owed by Lakefront Utilities during the 2017 test year:

	Description	Lender	Affiliated / Third Party	Date	Term	Principal	Rate
1	Note Payable	Town of Cobourg	Affiliated	09/12/2006	NA (On Demand)	$ 7,000,000	7.25%
2	Loan	Infrastructure Ontario	Affiliated	10/01/2012	15 years	$ 1,225,224	3.38%
3	Loan	Infrastructure Ontario	Affiliated	09/03/2013	15 years	$ 1,457,461	4.03%
	Total Debt					$ 9,682,685	4.54%
							Proposed

Lakefront Utilities describes its long-term debt on pages 7 and 8 of Exhibit 5.

Beginning at the bottom of page 8, and continuing on page 9 of Exhibit 5, and with Table 5-1, Lakefront Utilities has a short description of what it terms “notional debt”, and which seems to be the basis for its proposed 4.54% long-term debt rate.

(a) Please describe what Lakefront Utilities means by “notional debt” and how the description on pages 8 and 9 and Table 5-1 form the basis for the proposed long-term debt rate of 4.54%.

(b) Please describe how Lakefront Utilities’ definition of and application of notional debt is consistent with: 1) Section 4.4.1 of the Report of the Board on the Cost of Capital for Ontario Regulated Utilities (EB-2009-0084); and 2) section 3.1 of the OEB Staff Report on the Review of the Cost of Capital for Ontario’s Regulated Utilities.

(c) OEB staff notes that the OEB’s policies on long-term debt rates are applied to each debt instrument individually, taking into account the timing and the characteristics of the terms of each instrument, including whether the lender is affiliated or third party, whether the rate is variable or fixed, and the term of the loan. In this case, OEB staff notes that the two Infrastructure Ontario loans are third-party loans with fixed rates and fixed terms, and so would attract, for rate-setting purposes, their actuals rates of 3.38% and 4.03%. The Promissory Note to the Town of Cobourg is affiliated debt, with a fixed rate but with no fixed term, and so would attract the OEB’s current deemed long-term debt rate of 4.54%. As such, OEB staff provides the following analysis of the weighted average cost of long-term debt of 4.32% for setting Lakefront Utilities’ 2017 revenue requirement:

	Description	Lender	Affiliated / Third Party	Date	Term	Principal	Rate	Allowed Rate per OEB Policy
1	Note Payable	Town of Cobourg	Affiliated	09/12/2006	NA (On Demand)	$ 7,000,000	7.25%	4.54%
2	Loan	Infrastructure Ontario	Affiliated	10/01/2012	15 years	$ 1,225,224	3.38%	3.38%
3	Loan	Infrastructure Ontario	Affiliated	09/03/2013	15 years	$ 1,457,461	4.03%	4.03%
	Total Debt					$ 9,682,685	4.54%	4.32%
							Proposed	

The weighted average cost of long-term debt is determined by weighted the allowed rate for each debt instrument by the principal of each instrument.

Please provide Lakefront Utilities' views on OEB staff's analysis.

(d) Please confirm that the deemed long-term debt, should be updated along with the Return on Equity and deemed long-term debt rate at the time of the OEB's decision on Lakefront Utilities' application. In the alternative, please explain.

Exhibit 6 – Calculation of Revenue Deficiency

6-Staff-54

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 10 Tracking Sheet, and may also be included on other sheets in the RRWF to assist understanding of changes.

Also upon completing all interrogatories from OEB staff and intervenors please provide any updates to the following Microsoft Excel documents in working format: PILS, any Appendix 2 changes (e.g. cost allocation, rate design, and bill impacts, and so on as required), EDDVAR spreadsheet, and the updated cost allocation model (as per the interrogatory below) reflecting the revised revenue requirement in the updated RRWF.

Exhibit 7 – Cost Allocation

7-Staff-55
Ref: Ex.7/Tab 1/Sch.1 – Overview of Cost Allocation, Table 7.1 Weighting Factors

	Residential	General Service < 50 kW	General Service 50-2999 kW	General Service 3000-4999 kW	Street Lighting	Sentinel Lights	Unmetered Scattered Load
Insert Weighting Factor for Services Account 1855	1.0	2.0	10.0	10.0	1.0	1.0	1.0
Insert Weighting Factor for Billing and Collecting	1.0	2.0	7.0	7.0	1.0	0.1	5.0

As instructed by the OEB, Lakefront Utilities has used LDC specific weighting factors.

(a) Was a cost study conducted to determine the values in the table above?

(b) With respect to the General Service>50kW rate classes, what was the methodology used to determine the weighting factors?

(c) With respect to the Street Lighting and Sentinel Load classes, Lakefront Utilities notes that the costs incurred to provide services are the responsibility of the Town of Cobourg. Please explain why a weighting factor of zero was not used. If any changes are necessary, please make the necessary corrections.

Exhibit 8 – Rate Design

8-Staff-56
Ref: Ex.8/Tab 1/Sch.4 – Retail Transmission Service Rates
Ref: RTSR Model, Tab 5

The OEB issued a Rate Order for the 2016 Uniform Transmission Rates (EB-2015-0311) and also a Rate Order for Hydro One Distribution's Sub-transmission rates (EB-2015-0079) effective January 1, 2016. The OEB approved these rates as part of Lakefront Utilities' 2016 IRM application (EB-2015-0085).

2016 Uniform Transmission Rates

Network Service Rate	$3.66 per kW
Connection Service Rates Line Connection Service Rate Transformation Connection Service Rate	 $0.87 per kW $2.02 per kW

2016 Sub-Transmission RTSRs

Network Service Rate	$3.34 per kW
Connection Service Rates Line Connection Service Rate Transformation Connection Service Rate	 $0.78 per kW $1.77 per kW

OEB staff notes that the RTSR model filed with this 2017 cost of service application contains the old rates. Please provide an updated RTSR Adjustment Workform in working Microsoft Excel format reflecting the updated UTR's and Sub-Transmission Rates, as applicable. Please ensure that corrections to RTSR rates are captured in the updated Tariff of Rates and Charges provided by Lakefront Utilities.

8-Staff-57
Ref: Ex.8/Tab 1/Sch.3, Page 6
Ref: Cost Allocation Model, Tab O2

Table 8.2: Minimum and Maximum Fixed Charge as per the Cost Allocation Model

Cost Allocation Results - Minimum and Maximum MSC

	Cost Allocation - Minimum Fixed Rate (b)			Cost Allocation - Maximun Fixed Rate (b)		
Customer Class Name	Rate	Fixed %	Variable %	Rate	Fixed %	Variable %
Residential	$6.38	28.86%	71.14%	$13.14	59.45%	40.55%
General Service < 50 kW	$10.95	23.61%	76.39%	$23.96	51.67%	48.33%
General Service 50-2999 kW	$55.42	8.51%	91.49%	$86.76	13.32%	86.68%
General Service 3000-4999 kW	$192.21	1.74%	98.26%	$5,800.89	52.56%	47.44%
Street Lighting	$0.01	0.18%	99.82%	$4.08	73.01%	26.99%
Sentinel Lights	$0.77	10.18%	89.82%	$4.95	65.79%	34.21%
Unmetered Scattered Load	$10.57	39.83%	60.17%	$18.63	70.18%	29.82%

The table above shows the minimum and maximum monthly service charges as per the cost allocation model filed by Lakefront Utilities. Lakefront Utilities notes that it "proposes a Residential Monthly Service Charge (MSC) of $16.46 which falls between the minimum and maximum fixed charges calculated from the cost allocation model".

As seen in the table above, the minimum Residential MSC is $6.38 and the maximum is $13.14. Please explain the apparent discrepancy in the statement by Lakefront Utilities.

8-Staff-58
Ref: Ex.8/Tab 1/Sch.3 – Comparison of Fixed and Variable Charges under Current and Proposed Rates, Page 8
Ref: Ex.7/Tab 3/Sch.2 – Cost Allocation Results and Analysis, Page 14
Ref: Chapter 2 Appendices, Tab 2-P – Cost_Allocation

C) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios Most Recent Year: 2012	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	94.80%	92.53	94.57	85 - 115
GS < 50 kW	99.60%	101.71	102.09	80 - 120
GS 50-2999 kW	120.00%	104.55	104.60	80 - 120
GS 3000-4999 kW	57.50%	108.82	109.00	80 - 120
Street Lighting	111.70%	212.54	166.31	80 - 120
Sentinel Lighting	117.20%	96.38	96.02	80 - 120
Unmetered Scattered Load (USL)	94.80%	152.74	124.43	80 - 120

D) Proposed Revenue-to-Cost Ratios

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2017	2018	2019	
	%	%	%	%
Residential	94.57	94.57	94.57	85 - 115
GS < 50 kW	102.09	102.09	102.09	80 - 120
GS 50-2999 kW	104.60	104.60	104.60	80 - 120
GS 3000-4999 kW	109.00	109.00	109.00	80 - 120
Street Lighting	166.31	166.31	166.31	80 - 120
Sentinel Lighting	96.02	96.02	96.02	80 - 120
Unmetered Scattered Load (USL)	124.43	124.43	124.43	80 - 120

OEB staff notes that the proposed revenue to cost ratios for the Street Lighting and Unmetered Scattered Load rate classes are outside of the OEB-approved ranges. Chapter 2 of the Filing Requirement states that in cases where the ratios are outside of the OEB-approved ranges, distributors must ensure that that their cost allocation proposals include adjustments to bring them within the OEB-approved ranges. In making any such adjustments, distributors should address potential mitigation measures if the impact of the adjustments on the rate burden of any particular class or classes is significant.

In addition, if the distributor proposes to continue rebalancing rates after the cost of service test year, the ratios proposed for subsequent year(s) must be provided.

(a) Please explain why Lakefront Utilities has not provided a proposal to bring the ratios for these two rate classes within the OEB-approved ranges.

(b) Please provide an updated proposal and make the necessary corrections to the models in accordance with interrogatory 6-Staff-54.

8-Staff-59
Ref: Ex.8/Tab 1/Sch.3 – Comparison of Fixed and Variable Charges under Current and Proposed Rates, Table 8.5: Allocation of Shortfall

Table 8.5: Allocation of Shortfall

Customer Class Name	Adjustment Allocator	%	Allocation	Service RR	R/C
Residential	216,116	147.32%	(91,770)	2,584,063.24	0.89
General Service < 50 kW	(11,102)	-7.57%	4,714	666,178.93	1.02
General Service 50-2999 kW	(47,353)	-32.28%	20,108	1,108,359.65	1.06
General Service 3000-4999 kW	(11,179)	-7.62%	4,747	142,652.29	1.13
Street Lighting				139,281.77	1.20
Sentinel Lights	218	0.15%	(93)	5,722.11	0.95
Unmetered Scattered Load				36,567.91	1.20
	146,700	**100.00%**	**(62,294)**	**4,682,825.89**	

OEB staff is unable to reconcile the service revenue requirement noted in the table above or how this table ties back to Lakefront Utilities' rate design proposal.

Please provide an explanation for the table above.

Exhibit 9 – Deferral and Variance Accounts

9-Staff-60
Ref: EDDVAR Continuity Schedule, Tab 2 – 2015 Continuity Schedule

Column AL of the EDDVAR continuity schedule shows an adjustment of $737,547 to Account 1588 – Power for the 2012 year.

Please confirm that this adjustment is solely based on the findings of the audit completed by the OEB's audit group which is filed as Attachment A to Exhibit 9.

9-Staff-61
Ref: EDDVAR Continuity Schedule and Exhibit 9, Table 9.0

Lakefront Utilities has proposed for disposition a credit of $480,857 for Account 1580 RSVA – WMS Charges. However, Lakefront Utilities has not provided a break-down of the Account balance into its Sub-accounts.

(a) Please provide a break-down of Account 1580 RSVA – WMS Charge into the following sub-parts:

- Balance in the Control account excluding CBR Sub-accounts, principal and interest
- Sub-account CBR Class A, principal and interest
- Sub-account CBR Class B, principal and interest

(b) Lakefront Utilities' 2.1.7 RRR filings show credit balances in its CBR Sub-accounts for Class B as of December 31, 2015. Please provide a description of the nature of credit entries recorded in LUI's GL in 2015 in CBR Sub-accounts, given that there was no OEB approved rate for CBR.

(c) Does Lakefront Utilities serve any Class A customers? If not, please transfer the balances from the Sub-account CBR Class B to the Control account for allocating amounts to rate classes and for calculating the rate riders.