Lakefront
Utilities
Inc.

November 9, 2018

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 26th Floor, P.O. Box 2319
Toronto, ON M4P 1E4

Re: Lakefront Utilities Inc.
EB-2018-0049 - 2019 IRM Application – Standby Charge
Reply Submission

Dear Ms. Walli:

Pursuant to Procedural Order No. 1, please find enclosed Lakefront Utilities Inc.'s (LUI) Reply Submission in regard to the above matter.

Should the board have questions regarding this matter please contact me at agiddings@lusi.on.ca

Respectfully Submitted,

Adam Giddings, CPA, CA
Manager of Regulatory Compliance and Finance
Lakefront Utilities Inc.

Cc: Dereck C. Paul, President and CEO
Cc: Parties in EB-2018-0049

EB-2018-0049

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

AND IN THE MATTER OF an Application by Lakefront Utilities Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2019.

REPLY SUBMISSION OF
LAKEFRONT UTILITIES INC.

November 9, 2018

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Introduction

On August 13, 2018, Lakefront Utilities Inc. (LUI or the Applicant) filed an IRM application (the Application) with the Ontario Energy Board (the Board) under section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that LUI charges for electricity distribution, to be effective January 1, 2019. The Board assigned the Application file number EB-2018-0049.

Lakefront Utilities Inc's 2018 Distribution Rates were approved by the OEB on December 14, 2017, and were based on Lakefront's 2017 Cost of Service Application (EB-2016-0089). The Cost of Service application included a Cost Allocation Model, a Revenue-to-Cost Model, and a Rate Design Model, used to determine Lakefront's individual customer class fixed and variable distribution charges.

Lakefront was made aware of two General Service (GS) customers pursuing combined heat and power (CHP) projects. Both customers have acknowledged that they will require Lakefront Utilities to provide reserve capacity to back up their facilities when the load-displacement generation (LDG) is available. Further, with the development of the Smart Grid, Smart Meters, and installation of MIST meters, Lakefront envisions more customers embracing load displacement generation or behind-the-meter generation as a solution for energy savings and energy independence from the grid.

The standby rate is charged to customers who have their own load displacement generation and require reserved capacity in case their generation goes offline, and they need energy from the distribution grid. This rate enables Lakefront to recover the distribution costs for the system capacity that is reserved for the customer and not available for other customers.

LUI offers the following reply to the submissions on the standby charge from Board Staff, the Vulnerable Energy Consumers Coalition (VECC), ECNG Energy LP (ECNG), and Northumberland Hills Hospital (NHH).

LUI will address the following topics in this submission:

1. Calculation of the Standby Charge
2. OEB Consultation on Standby Charge
3. Approval of Standby Charge in an IRM
4. Customer Engagement
5. The Impact
6. Conclusion

1. Calculation of the Standby Charge

ECNG summited that the analysis provided by Lakefront Utilities Inc. assumed that behind the meter generation will run 24/7. Further, ECNG believes that LUI's analysis does not account for the reasonable likelihood of any shutdowns where the customer obtains 100% of their consumption from the grid. Therefore, ECNG's conclusion was that LUI would essentially be double billing customers during that period.

VECC further submitted concerns regarding Lakefront Utilities' calculation of the annual lost revenues for each of the two CHP projects. VECC's concern was an explicit statement of assumptions had not been provided and it was unclear if the calculations included an estimation of outage time related to load displacement generation. VECC presumed that further discovery might show that estimated annual lost revenues are not above Lakefront Utilities' materiality threshold when outages are taken into consideration.

LUI Reply Submission

LDCs have, as a condition of license, an obligation to maintain system integrity. Further, the mechanism for profit (electricity rates) is limited in regulated monopoly electricity markets. However, as customers choose not to buy the product (electricity) from the traditional provider (the electric utility), the traditional business model of the regulated monopoly electric utility ceases to be viable.

Customers moving off-grid may choose not to sever their connection from the grid entirely. Rather, they may elect to preserve grid connection as a kind of insurance, while simultaneously minimizing electricity purchase in favour of CHP. The partial energy independence would force Lakefront to continue to maintain its cost of electricity distribution infrastructure, while its primary source of revenue (actual electricity sold) gets increasingly smaller. "What is certain is that if companies in the power sector don't stay ahead of change, the challenges they face will intensify. New market models and new business models will become established as a result of energy transformation and could quickly eclipse current company strategies.[1]"

The potential standby charge is important because there is the likelihood that there will be times when generation is not available i.e. shut down for maintenance or emergency repairs. This requires Lakefront Utilities to have reserved capacity in place to service any eventualities that may occur. Further, as technology develops, Lakefront may be asked to standby with capacity in situations where the true potential delivered peak load is seldom seen, a scenario where no recovery is earned by Lakefront for standing by for a sudden, large load requirement.

Based on the estimated electricity savings the two customers would obtain from their CHP application, Lakefront Utilities would estimate an annual revenue loss of over $100,000 in the absence of a standby charge, as follows:

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[1] PwC Global Power and Utilities Survey, May 2015

Details	CHP Project #1	CHP Project #2
Generator Nameplate Capacity	287	4,000
Estimated Electricity Savings (kW)	44	235
Standby Electricity	243	3,765
2018 Rate (per kW)	3.4089	2.1063
Monthly Lost Revenue - 2018 Rate	$830	$7,931
Annual Lost Revenue - 2018 Rate	$9,955	$95,171

Lakefront Utilities confirms that no assumptions were utilized when preparing the annual lost revenue calculation. All data was obtained from the customer's Save On Energy Process and Systems Program, submitted to the Independent Electricity System Operator, and the calculations include an estimation of outage time related to load displacement generation. Lakefront's proposed standby charge is based on the applicable General Service 50 to 2999 kW or General Service 3000 to 4999 kW distribution volumetric rate applied to the generator's peak demand. Lakefront's proposal for a standby charge is consistent with other LDCs and consequently Lakefront does not agree with ECNG's assertion that Lakefront would be "essentially double billing customers". The intent of the standby charge is to ensure that customers without behind the meter generation do not subsidize customers with behind the meter generation.

With the installation of the customer's CHP, Lakefront's estimated annual lost revenue for 2019 is approximately $100,000. Over the next three years (until Lakefront's next rebasing period) the cumulative revenue loss could be in excess of $300,000. A loss that is significant and that is above and beyond reasonable exposure of risk for a small utility. As suggested by VECC, "further discovery may show that estimated annual lost revenues are not above Lakefront Utilities' materiality threshold when outages are taken into consideration". As previously noted, Lakefront's calculations are based on applications submitted to the IESO. Therefore, it's reasonable to expect that the estimated revenue loss of $100,000 is accurate and is significantly larger than Lakefront's materially threshold of $50,000. The Ontario Energy Board noted "Distributed energy resources (DER) are becoming more cost effective and increasing penetration."[2] It's likely that there will be additional Lakefront customers that wish to pursue distributed generation prior to Lakefront's next cost of service filing in 2022, therefore Lakefront expects that the annual revenue loss of $100,000 is conservative.

[2] Staff Discussion Paper, Rate Design for Commercial and Industrial Electricity Customers: Aligning the Interest of Customers and Distributors, March 31, 2016. p.3

2. OEB Consultation on Standby Charge

ECNG's position is the request for a reasonable review of the standby charge independently of the IRM and that it would be appropriate to wait until the outcome of the OEB's consultation on Commercial and Industrial Rate Design (EB-2015-0043) before determining any standby rate methodology.

NHH also submitted that it would be reasonable to wait until the outcome of the Board's consultation on the issue before determining the appropriate standby rate methodology. NHH believes it is reasonable to expect that the Board will have a broadly applicable policy already in place by the time of LUI's next rebasing application and thus that will be an appropriate stage to seek a standby rate.

OEB Staff referenced that there is a policy consultation currently ongoing that is examining this very issue on an industry-wide basis. OEB Staff anticipates that this policy consultation will conclude well before Lakefront Utilities' next rebasing application and the outcome of the consultation may address the implementation timeline of any new standby charge methodology.

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"The pace of change enabled by significant technological advancements is affecting how energy is produced, transported and consumed[3]". It's important to note there is an exhaustive list of technologies that have the potential to disrupt the traditional business model of utilities:

1. Combined heat and power;
2. Battery energy storage;
3. Demand response;
4. Distributed generation;
5. Electric vehicles;
6. Microgrid;
7. Microturbine;
8. Net metering

In a competitive environment, both distributors and generators can negotiate details that would benefit both parties. The OEB's role should be to ensure that the economic and financial viability of the energy sector is maintained, and the interest of all consumers are protected.

The pace of change is rapid and accelerating which confirms there is a need to act now to harness the full benefits of the opportunities presented. As commented by SEC in their response to EB-2015-0043: "The role of the electricity distributor is entering a state of flux. A lot of change is likely on the horizon, some of them potentially material"[4]. However, LDCs are already experiencing a significant disturbance to their

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[3] Rate Design for Commercial and Industrial, EB-201-0043, p.1.

[4] School Energy Coalition, Submission on EB-2015-0043, p.2.

business as a direct consequence of distributed generation. The industry is inherently slow to act, and utilities are expected to follow a five-year plan. But the rise of distributed generation is creating a new environment, an environment where utilities should be allowed to embrace flexibility if they want to survive. The grid is changing, and it only follows that utilities will need to adapt their business models. The faster that a utility acts on distributed generation, the more chance they will have to thrive off the changes.

As recommended by ECNG, NHH, and OEB Staff, Lakefront Utilities should postpone its standby charge application until the outcome of the Board's consultation on the issue is received. NHH feels it is "reasonable to expect that, by the time LUI next rebases, and thus is at an appropriate stage to seek a standby rate, the Board will have a broadly applicable policy already in place." The OEB's discussion paper was released in May 2015, and the most recent update was in November 2017 when the OEB Staff held many consultation meetings with stakeholders and customer groups to garner feedback on the proposal. The consultation meetings indicated that the "next step is consulting with customer groups to understand the impacts on customers, get ideas for mitigation strategies, develop an implementation plan that works for business"[5]. Considering no updates have followed the OEB's November 30, 2017 presentation and while the electricity sector continues to experience rapid change, Lakefront does not agree with NHH that it's reasonable to expect that a standby rate will be set by the time LUI next rebases.

[5] Rate Design for Commercial and Industrial, EB-201-0043, November 30, 2017 Presentation.

3. Approval of Standby Charge in an IRM

NHH submitted that Lakefront's proposal to add a standby charge in an IRM application is inappropriate. Further, they considered that IRM applications are, with few exceptions, meant to be mechanistic in nature. NHH referenced The Board's Filing Requirements that the "IRM process is not the appropriate way for a distributor to seek relief on issues which are specific to only one or a few distributors, more complicated relative to issues typical or an IRM application, or potentially contentious. In essence, NHH proposed that LUI is seeking relief for loss of customer load and that LUI would not be allowed to seek relief from the Board during an IRM period caused by the shutdown of a significant customer.

VEC submitted that due to the complexities introduced through the introduction of new rates that have not existed before, an IRM application is not a suitable place to establish a standby rate. Further, VECC considers that new rates should be done as part of a Cost of Service application so that a holistic and fair view of costs and cost allocation can be undertaken to ensure the "right" rate is designed.

OEB staff also submitted that Chapter 3 of the Filing Requirements specifically provides that "the IRM process is not the appropriate way for a distributor to seek relief on issues which are specific to only one or a few distributors, more complicated relative issues typical of an IRM application, or potentially contentious."

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Ratemaking has evolved to achieve multiple policy goals such as providing energy service, recovering utility costs, ensuring that energy is affordable, incenting energy efficiency, and encouraging economic development.

The intervenors indicated that the process for designing new rates and changing existing rates is a time-consuming process that can often be highly contentious. Lakefront submits that the Ontario Energy Board should balance the increasingly complex linkage between utility system costs and customer rates and prices.

The Board's Filing Requirements state that the "IRM process is not the appropriate way for a distributor to seek relief on issues which are specific to only one or a few distributors, more complicated relative to issues typical of an IRM application, or potentially contentious."[6] Lakefront's request for approval of a standby charge for customers installing load displacement generation is consistent with and follows previous distributors' applications which have received OEB Decisions approving the class-specific variable distribution charge to be applied to displaced load. Therefore, Lakefront submits that the proposed standby charge rate is neither complex nor contentious.

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[6] *Ontario Energy Board Filing Requirements for Electricity Distribution Rate Applications – 2018 Edition for 2019 Rate Applications*, Chapter 3, Incentive Rate-Setting Applications, p.30.

Further, a standby charge rate is not unique. There are approximately 15 LDCs that currently have a standby charge rate. As mentioned by NHH, Energy+, Niagara-on-the-Lake Hydro, and Erie Thames Powerlines have all recently applied for a standby charge. Therefore, Lakefront does not agree with the intervenors that a standby charge rate is "specific to the distributor". Moreover, Lakefront notes that in EB-2017-0038 (as referenced by NHH) the lost revenue for Erie Thames Powerlines in the absence of a standby charge would be immaterial. Therefore, it's reasonable that the LDC waited until their next rebasing period.

NHH maintains that it would be procedurally unfair to have the issue decided in the context of an IRM proceeding. Lakefront feels that it would be unfair to the remaining Lakefront customers that they should have to pay for costs that are directly attributable to a specific customer until Lakefront's next rebasing application for 2022 rates. Lakefront Utilities submits that the significant loss in revenue, potential effect on operating and capital costs, potential effect on the distribution system, and cross subsidization far outweigh the intervenor's concerns regarding the appropriateness of adding a standby charge in an IRM application.

Lastly, Although LUI agrees that the IRM is intended to be mechanistic in nature, LUI notes that the OEB does allow for updates to the rate design within an IRM application. i.e. adjustments to revenue to cost ratios, adjustments for residential rate design, disposal of DVA and LRAMVA balances.

4. Customer Engagement

ECNG expressed concerns regarding Lakefront's lack of consultation and suggested that the determination of any standby charge be part of a process of customer engagement activities. Further, ECNG comments that the potential impact of a standby charge could be significant and therefore robust planning, informed by customer preferences and driven by benefits to customers, with appropriate pacing and prioritization to control costs and manage risk is a key consideration in rate applications.

NHH also referred to customer engagement, specifically that there is little excuse for LUI not to conduct customer engagement activities with respect to the proposal. NHH also submitted that LUI should be required to consult with its customers before filing any proposal that has such a significant impact on specific customers.

OEB Staff also noted that Lakefront Utilities has not demonstrated that its customers have been notified of the details of its proposal other than indicating that it has had discussions with two General Service customers regarding potential combined heat and power projects.

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"Planning is an ongoing utility activity, not just something that is done in preparation for a rate application. Likewise, customer engagement to inform utility planning must also be an ongoing activity."[7]

Lakefront was engaged in discussions with the NHH in late September to discuss its IRM Application and scheduled a meeting with NHH on October 2, 2018 to discuss the standby charge. The meeting was cancelled by NHH and has not been rescheduled. Customer engagement associated with distributed generation and CHP programs across the sector is not necessarily solely the LDC's responsibility. As previously mentioned, there are approximately 15 LDCs with a standby charge and Lakefront expected that the two customers considering a CHP program would have been informed of the possible standby charge by their third-party contractor before they initiated the process or at minimum inquire with Lakefront on any potential impact. As previously stated, Lakefront was only aware through the IESO applications of the CHP programs.

Lakefront reviewed the Cost of Service filing for the following:

1. EB-2017-0038: Erie Thames Powerlines

   Minimal customer engagement was conducted prior to the Cost of Service filing. The only mention of customer engagement was "ETPL has been working closely with its customers to

[7] Ontario Energy Board, Handbook for Utility Rate Applications, October 13, 2016, p.52

which standby charges would apply as they have been adding behind the meter generation to which Gross Load billing would apply".[8]

2. EB-2018-0056: Niagara-on-the-Lake Hydro

   The only mention of customer engagement in the Cost of Service filing was that "NOTL Hydro has discussed this standby charge with the customer that will be affected". [9]

CHP customer #1's application was not completed until May 31, 2018 and CHP customer #2's application was not completed until June 28, 2018. Once the applications were completed, Lakefront spent time analyzing the effect the CHP projects would have on distribution revenue and determined that a standby charge would be necessary in its IRM application. That conclusion was completed a week prior to Lakefront's IRM filing date of August 13, 2018.

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[8] EB-2017-0038, OEB Staff Interrogatories, August 31, 2018, p.119.

[9] EB-2018-0056, NOTL Hydro Exhibit 7, August 2018, p.15.

5. Impact

Lakefront Utilities Inc., in its revised submission to the OEB regarding the preliminary question, indicated that in the absence of a standby charge and based on the material annual revenue loss, Lakefront may be forced to proceed with a Cost of Service application earlier than intended. NHH assumes that LUI is referring to potentially performing outside the Board's ROE dead band of +/- 300 basis points so as to hit the trigger for the off-ramp.

OEB Staff submitted that during an IRM term electricity distributors are expected to deal with many different changes to the assumptions that underpin their rates arising from their most recent cost of service proceeding. OEB Staff is of the view that unless Lakefront Utilities demonstrates potential financial harm in the absence of new standby charges for 2019, that such a request should be denied.

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"A utility's core business in serving customers is asset management, and strong asset management is essential to delivering reliable and quality energy services that customers value. Strong planning will help drive operational effectiveness, and the utility system plan will be an important component of the utility's business plan which supports the rate application".[10]

Lakefront submits that NHH's assumption regarding Lakefront performing outside of the Board's ROE dead band of +- 300 basis points is an assessment that uses a very narrow, single-factor lens that fails to get into the complexities of some of the potential issues.

There is the potential for Lakefront to be significantly impacted by distributed generation. Lakefront must design and build its infrastructure based on the aggregated demand required by all customers. With the development of the Smart Grid, Smart Meters and installation of MIST meters, Lakefront envisions more customers embracing load displacement generation or behind-the-meter generation as a solution for energy savings and energy independence from the grid. As revenue recovery is based on either full or partial volumetric usage, customers that have implemented CHP would pay a disproportionate amount less than they should for grid connectivity, considering the assets within the distribution system.

Lakefront Utilities would also have a pressing need to repair and renew their transmission and distribution infrastructure which directly affects the customer implementing CHP. The lack of a standby charge would result in all other customers subsidizing the recovery of these costs. That is, the increased cost of supporting a network that can integrate distributed generation sources combined with the decline in electricity sales leads to a situation where more revenue is needed from a smaller pool of remaining ratepayers. The beginnings of this scenario have already been realized. In 2014 Barclays downgraded the entire electric sector as it "sees long-term challenges to electric utilities from solar energy…"[11]

[10] Handbook to Utility Rate Applications, October 13, 2016, p.12-13

[11] https://www.barrons.com/articles/barclays-downgrades-electric-utility-bonds-sees-viable-solar-competition-1400859916, May 23, 2014

Lakefront Utilities submits that an annual decrease in distribution revenue of $100,000 is a compelling argument for financial harm. Although Lakefront may continue to meet their Return on Equity requirement, this would be accomplished by significant reductions in operating and maintenance expenditures and/or capital upgrades to account for the decrease in distribution revenue associated with the CHP projects. Moreover, any decreases in operation and maintenance expenditures and/or capital upgrades could have serious implications on the reliability of Lakefront's infrastructure, including the impact, frequency, and duration of outages. Failure to review these costs would be contrary to good regulatory practice.

6. Conclusion

Distributors are essential service providers and a vital piece of any electricity system. LDCs own and make investments to grow their electricity distribution system infrastructure, in order to deliver power more reliably to more customers. New developments in distributed generation are presenting disruptive challenges to a safe and reliable system. These challenges arise in the form of higher customer expectations, greater financial pressures, and restrictive regulations. To overcome these challenges, Lakefront must change its traditional business activities in order to remain a viable component of Ontario's future.

The traditional role of electric utilities is diminishing in the face of technology, customer, financial, regulatory, and policy changes occurring in the industry. These changes will determine the future viability of local distribution companies in Ontario. Financially, utilities are seeing a declining trend in electricity demand growth. While there are more customers overall, individually, they need less power from their utility. At the same time, the grid infrastructure is aging and needs to be replaced or renewed with more advanced equipment that will be able to integrate many new energy technologies. The regulatory structure needs to evolve over time and incent LDCs to meet customer's evolving needs and desires. Distribution rates should not be used as a vehicle to encourage customers' participation in distributed generation, where there is no opportunity for distributors to recover lost revenues.

A standby charge focuses on ensuring that customers make investments in distributed generation and adjust their ways that benefits the system. Lakefront's request for a standby charge incorporates a volumetric rate to allow customers to utilize conservation to a greater affect.

For the reasons set out above, Lakefront Utilities is of the view that the Ontario Energy Board should consider Lakefront's request for standby charges.