Lakefront
Utilities
Inc.

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December 23, 2024

BY RESS

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

Re:

EB-2024-0038 - 2025 Incentive Rate Mechanism ('IRM') Application
Lakefront Utilities Inc. – Interrogatory Responses

On September 9, 2024, Lakefront Utilities Inc. (LUI) submitted its IRM Application (EB-2024-0038) for 2025 rates.

Attached are the responses to Ontario Energy Board (OEB) Staff, the Coalition of Concerned Manufacturers and Businesses of Canada (CCMBC), and the Vulnerable Energy Consumers Coalition (VECC), which were received on December 2, 2024.

The attached document identifies interrogatory VECC-4, which would benefit from additional time to provide a more comprehensive response. LUI respectfully requests an extension for this interrogatory, with a proposed filing date of January 17, 2025, to ensure that key staff have sufficient time to address it accurately.

We appreciate your consideration of this request. Should you have any questions or need further information, please feel free to contact us. Thank you for your attention to this matter.

Sincerely,

DW

Danielle Wakelin
Manager of Regulatory Compliance
Lakefront Utilities Inc.

b) Since LUI believes that it can ask for an ICM after a project has been placed in service, why did LUI not request for this in its application for 2024 rates?

LUI Response:

The decision not to apply for ICM funding for the project in LUI's 2024 rates application appears to be influenced by the judgment of the previous Chief Financial Officer (CFO). Specifically, the CFO may have opted not to request ICM funding because the project was still under construction at the time.

The decision to include the project in LUI's current application reflects a thoughtful alignment with the spirit and intent of the Incremental Capital Module (ICM) framework, recognizing the importance of regulatory consistency and transparency in recovering significant capital expenditures.

By bringing forward the application now, LUI demonstrates its commitment to working within the Ontario Energy Board's (OEB) established mechanisms for addressing material capital investments. This action ensures that LUI's stakeholders, including its customers, benefit from a balanced approach to funding critical infrastructure, consistent with the objectives of the ICM framework. This approach upholds the principle of regulatory responsiveness and effective rate-setting practices.

c) Why is LUI basing its request for ICM eligibility based on actual spending in 2023 instead of the book value of the substation on January 1, 2025?

LUI Response:

LUI's decision to base its Incremental Capital Module (ICM) request on actual spending in 2023, rather than the book value of the substation as of January 1, 2025, reflects its understanding of the OEB's adjudication process and the flexibility inherent in the ICM framework.

By applying based on 2023 actual expenditures, LUI aligns its application with the principle that ICM funding is intended to address discrete, material capital investments that exceed the normal capital expenditures accounted for within the utility's rates. This approach ensures that the application is rooted in actual and demonstrable financial needs, which can be clearly assessed by the OEB.

LUI proceeded with the application in good faith, recognizing that the OEB has the authority and expertise to evaluate the eligibility of the project based on all relevant evidence, including the timing of expenditures and the book value of assets. This reflects LUI's commitment to transparency and regulatory compliance while respecting the OEB's role in adjudicating the request as it sees fit.

d) Considering that other Ontario distributors have not requested ICM for a project after the project was placed in service, what are the "circumstances" that makes LUI claim that its request is justified?

LUI Response:

LUI acknowledges that other Ontario distributors may not have requested Incremental Capital Module (ICM) funding for projects after they were placed in service. However, LUI cannot speak to the unique circumstances or strategic decisions of other utilities. Each utility operates within its own context, guided by specific operational, financial, and regulatory considerations.

LUI believes it is within its rights to apply for ICM funding for this project, as the Ontario Energy Board (OEB) allows utilities to present applications supported by evidence of materiality, prudence, and need. The ICM framework is designed to provide flexibility to address significant and discrete capital investments, and LUI trusts the OEB to adjudicate its application based on its merits, within the framework of the established filing requirements.

This approach reflects LUI's commitment to ensuring regulatory compliance and acting in the best interests of its stakeholders.

CCMBC-2
Reference: 3.3.2.1 Incremental Capital Module (ICM) Filing Requirements, page 47
Preamble: LUI is requesting approval for incremental capital funding for 2025 with respect to a new 27.6 kV substation for a total estimated incremental capital expenditure of $2,535,311.

Questions:

a) The quoted text indicates that $2,523,311 is the estimated incremental capital expenditure. Does that mean that it excludes allocated overhead costs?

LUI Response:

The $2,523,311 includes overhead cost.

b) What was the actual cost of the substation at its completion in 2023?

LUI Response:

Total actual cost at completion in 2023 was $2,535,310.85.

CCMBC-3
Reference: 3.3.2.1 Incremental Capital Module (ICM) Filing Requirements, page 47
Preamble: "Additionally, the sudden need for the project in 2023 was driven by unforeseen residential developments, notably influenced by the Provincial Government's incentives to encourage faster home construction. Cobourg has experienced an uptick in developments as a result of these incentives."

Questions:

a) Please provide more information about the "unforeseen residential developments" including the following:

   i. The number of residential, commercial and industrial customers in each development,
   ii. How and when was LUI informed of each development,
   iii. Has construction started of any development,
   iv. The number of premises connected by LUI to date in each development

LUI Response to CCMBC-3 a) i,ii,iii, and iv:

Please see Figure 1 below. This is based upon actual residential developments from 2020 to 2024 and forecasted residential development for the period 2025 to 2028. There are no commercial / industrial developments embedded in the residential developments listed. LUI is typically informed of residential developments through the Town of Cobourg's Development Review Team (DRT) as LUI is a team member. The DRT is informed of residential developments at the initial contact between the developer and the Town of Cobourg, typically a few years prior to the actual construction of the subdivision.

Figure 1: Subdivision 2020 – 2028

Subdivision Name	Number of Lots	Estimated Load (kVA)	Informed of Project Date (Month/Year)	Construction Started (Yes/No)	Lots Connected To Date
New Amherst Stage 2, Phase 2	156	468	08/2019	Yes	55
Nickerson Woods	23	69	12/2021	Yes	23
Gates of Camelot Stage 5, Phase 1	83	249	01/2022	Yes	83
Densmore Meadows	124	372	06/2021	Yes	124
Tribute Phase 1	182	546	01/2021	Yes	169
Gates of Camelot Stage 5, Phase 2	155	465	01/2022	Yes	55
Mason Homes 425 King St. E	27	81	05/2021	Yes	27
Tribute Phase 2	105	315	01/2021	No	0
Victoria Meadows	72	216	01/2022	No	0
New Amherst Phase 3	135	405	04/2022	No	0
Tribute Phase 3	163	489	01/2021	No	0
Tribute Phase 4	176	528	01/2021	No	0
Tribute Phase 5	233	699	01/2021	No	0
Tribute Phase 6	182	546	01/2021	No	0
Sunnyside Village	100	300	08/2024	No	0
Mistral - Brook Road North	300 (Est)	900	01/2022 (Est)	No	0

b) Please file copies of all correspondence between the developers of these residential developments and LUI since 2023.

LUI Response:

Due to the following statement by OEB staff "Please note, Lakefront Utilities Inc. is responsible for ensuring that all documents it files with the OEB, including responses to OEB staff interrogatories and any other supporting documentation, do not include personal information (as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*), unless filed in accordance with rule 9A of the OEB's *Rules of Practice and Procedure*" pertaining to these interrogatories, Lakefront isn't able to provide the requested data.

c) Please list the Provincial Government Incentives that LUI is referring to in the quoted text.

LUI Response:

Ontario has introduced the Housing-Enabling Water Systems Fund to help municipalities develop, repair, and expand critical water infrastructure. This initiative aims to unlock housing opportunities by ensuring communities have the necessary water infrastructure in place to support growth.

The fund has received substantial investment, with over $1.2 billion allocated to projects across the province. Of this, $825 million is dedicated to the Housing-Enabling Water Systems Fund, focusing on drinking water, wastewater, and stormwater infrastructure.

These investments are integral to Ontario’s broader strategy to build at least 1.5 million homes by 2031, addressing the province’s growing demand for housing and ensuring sustainable community development.

The Ontario government recently made a $25 million investment through this fund which will significantly benefit Cobourg by advancing critical infrastructure and housing projects.

The funding will enable the expansion of Cobourg's wastewater system and watermains, which is essential to supporting the construction of 2,266 new homes in the Cobourg East Community Secondary Plan area. With improved water infrastructure, the town can accommodate a growing population and facilitate the development of new housing projects.

The expanded infrastructure will pave the way for diverse housing options, including affordable and rental units. This aligns with Cobourg’s Affordable & Rental Housing Community Improvement Plan (CIP), which provides financial incentives such as fee waivers, development charge grants, and property tax increment grants. These initiatives aim to stimulate housing development across various income levels.

The construction of new homes will bring significant economic benefits, including job creation in construction and related industries, increased local spending, and the attraction of new residents to the area. This activity is expected to have a positive ripple effect on Cobourg's local economy.

New housing projects will contribute to the growth of the Cobourg East Community Secondary Plan area, fostering a vibrant and sustainable community. This includes a variety of housing types, such as mixed-income developments, smaller units, and emergency or transitional housing.

These initiatives collectively address Cobourg's housing challenges, promote economic growth, and enhance the quality of life for residents, ensuring a brighter and more sustainable future for the community.

CCMBC-4
Reference: Eligibility for Incremental Capital, page 48
Preamble: “In order to be eligible for incremental capital, an ICM claim must be incremental to a distributor’s capital requirements within the context of its financial capacities underpinned by existing rates;”

Questions:

a) Please confirm that “financial capacities underpinned by existing rates” are determined by the materiality threshold formula.

LUI Response:

Yes, the term “financial capacities underpinned by existing rates” is determined by the materiality threshold formula.

The Ontario Energy Board (OEB) uses the materiality threshold formula to evaluate whether a distributor has sufficient financial capacity within its current rates to fund capital projects. The formula ensures that the incremental capital module (ICM) mechanism is only used for significant, discrete projects that cannot be financed through the distributor's existing capital budget as supported by the revenue generated from its current rates.
This formula provides a benchmark to assess whether the project’s costs exceed the distributor’s capacity to fund it from the regular rate structure, establishing the eligibility for ICM funding.

b) What was the financial capacity underpinned by existing rates of LUI in 2023?

LUI Response:

LUI believes this question is sufficiently addressed on Sheet "8. Threshold Test" of the ICM model, as required by the OEB. This sheet provides the calculations and details necessary to determine the financial capacity underpinned by existing rates.

c) What was the financial capacity underpinned by existing rates of LUI in 2025?

LUI Response:

LUI believes this question is sufficiently addressed on Sheet "8. Threshold Test" of the ICM model, as required by the OEB. This sheet provides the calculations and details necessary to determine the financial capacity underpinned by existing rates.

CCMBC-5
Reference: IRM Application, Section 3.3.3, Page 54
Preamble: “In 2023, Lakefront Utilities Inc. energized a new 27.6 kV substation (MS28-3) on Ontario Street in Cobourg. This critical infrastructure project was undertaken to address the growing capacity requirements, improve reliability, and introduce additional redundancy in our community’s electrical distribution network.” […] “Project Justification: 1. Growing Capacity Requirements: The residential and commercial developments in

our service area have significantly increased the demand for electricity. The new substation adds necessary capacity to manage this growth efficiently. A key theme of the Ontario Energy Board's guidance is that utilities should align their investment plans with customer needs, and adopt an outcomes-based approach to tracking their performance."

Questions:

a) Can you please list which residential and commercial developments in your service area have or will cause the significantly increased demand for electricity mentioned in this passage, necessitating the new 27.6kV substation (MS28-3) on Ontario Street in Coburg?

   LUI Response:

   The load growth in LUI's service area is related to the vacant lands in the north-east area of the service territory. These lands are designated for residential/commercial load growth over the next 10-year period. There are several developers that have purchased land for development in the area including, but not limited to, Tribute and Mistral. Developers have begun development and have several phases of development planned over the next 10-year period.

b) If those developments did not occur or do not go ahead, would the new MS28-3 substation be unavoidably required today?

   LUI Response:

   If the above developments did not occur, MS28-3 would still be required today. MS28-3 was constructed for 3 main reasons: 1) Load Growth, 2) 4.16 to 27.6 kV Voltage Conversion, 3) Reliability/Redundancy.

CCMBC-6
Reference: IRM Application, Section 3.3.3, Page 54
Preamble: "Lakefront deliberated on invoking cost-sharing with residential developers, as directed in the Distribution System Code (DSC), to mitigate the financial impact on our existing customers. However, we are persuaded that recent events, including the Ontario government's intervention in overturning an OEB directive regarding Enbridge's economic evaluation for rural expansion, may override this requirement. Hence, in this application, we are proposing full recovery of the substation costs from our entire customer base. We seek OEB guidance and direction on this matter to ensure compliance and equitable cost distribution."

Questions:

a) Why does Lakefront believe it is more equitable to have all ratepayers pay for the MS28-3 Substation Project instead of just the developers for whose development projects the substation is required? Why is it equitable for ratepayers to subsidize what would otherwise be costs for those developers?

LUI Response:

Lakefront's proposal to distribute the costs of the MS28-3 Substation Project across all ratepayers, rather than solely to the developers necessitating the substation, is influenced by recent governmental interventions and considerations of equitable cost distribution.

Traditionally, the Ontario Energy Board (OEB) adheres to a "beneficiary pays" principle, where entities directly benefiting from new infrastructure, such as developers, bear the associated costs. This approach ensures that existing customers are not burdened with expenses from which they do not directly benefit. However, Lakefront's stance is shaped by recent policy shifts and government directives that aim to balance immediate development costs with broader economic and social benefits.

A pertinent example is the Ontario government's response to an OEB decision regarding Enbridge's natural gas expansion. The OEB had mandated that developers cover the full costs of new connections upfront to mitigate the risk of stranded assets amid the energy transition. The government has taken steps to attempt to overturn this decision, allowing costs to be spread over time and shared among a broader customer base, citing concerns that upfront costs could hinder housing development and

In 2024, the Ontario government introduced amendments to the Ontario Energy Board Act, 1998, through Bill 165, the Keeping Energy Costs Down Act, 2024. These amendments empower the government to issue directives to the OEB concerning various matters, including economic evaluations related to system expansions for housing developments. The goal is to ensure that energy infrastructure costs do not hinder growth and that the financial responsibilities are balanced among stakeholders.

Additionally, in November 2023, the Minister of Energy issued a Letter of Direction to the OEB, emphasizing the importance of aligning energy infrastructure development with the government's housing and economic objectives. The letter requested the OEB to review electricity distribution system expansion connection and revenue horizons to ensure an appropriate balance between growth and ratepayer costs.

These directives and legislative changes reflect the government's active role in guiding the OEB's application of economic evaluations, particularly in the context of development projects, to support provincial growth and housing initiatives.

Lakefront perceives that, in light of such government actions, applying the traditional cost-sharing model might be overridden by provincial directives favoring cost distribution across all ratepayers. By proposing to recover the substation costs from the entire customer base, Lakefront aims to align with current governmental policies that support development and economic expansion, while seeking OEB guidance to ensure compliance and fairness in cost allocation.

In summary, Lakefront's approach reflects a response to recent governmental interventions that prioritize broader economic benefits and equitable cost distribution, even if it means existing ratepayers subsidize infrastructure primarily benefiting new developments.

b) In Lakefront’s opinion, would more equitable cost distribution be achieved if all taxpayers, instead of all ratepayers, subsidized this cost? Why or why not?

LUI Response:

Lakefront acknowledges the potential benefits of funding the MS28-3 Substation Project through general taxation, as it could distribute costs more broadly and support regional development. However, we are committed to adhering to the current Ontario Energy Board (OEB) regulations, which emphasize the "beneficiary pays" principle. These principal mandates that the costs of new infrastructure are primarily borne by those who directly benefit from it—in this case, the developers whose projects necessitate the substation.

Recent government interventions, such as the proposed amendments to the Ontario Energy Board Act, 1998, indicate a shift towards more flexible cost allocation frameworks to facilitate infrastructure development. For instance, the Ministry of Energy and Electrification has consulted on potential regulatory changes that would alter the cost responsibility framework for certain electricity system infrastructure, including how costs are allocated to customers and recovered by utility companies.

Lakefront recognizes the importance of adhering to the Ontario Energy Board's (OEB) "beneficiary pays" principle, which typically assigns the costs of new infrastructure to those who directly benefit—in this case, the developers necessitating the MS28-3 Substation Project. However, we are observing a disparity between the pace of new home construction and the deployment of underlying infrastructure. This misalignment poses challenges in equitably distributing costs and ensuring that infrastructure investments are timely and effective.

To address this issue, we are proposing a hybrid cost allocation model as an interim solution until our next cost of service application. This approach would involve eventually sharing the substation costs between developers and the broader ratepayer base, reflecting both the immediate beneficiaries and the long-term communal advantages of enhanced infrastructure. This model aims to balance fairness with the current realities of development and infrastructure deployment.

We are committed to compliance with existing OEB regulations and seek guidance on implementing this hybrid model within the current framework. By the time of our next cost of service application, we anticipate having a clearer understanding of actual growth patterns, enabling us to propose a more refined and equitable cost allocation strategy that aligns with both regulatory requirements and the evolving needs of our community.

CCMBC-7
Reference: MS28-3 Substation Project**,** Page 54
Preamble: In 2023, Lakefront Utilities Inc. energized a new 27.6 kV substation (MS28-3) on Ontario Street in Cobourg. This critical infrastructure project was undertaken to address the growing capacity requirements, improve reliability, and introduce additional redundancy in our community's electrical distribution network."

Question:

In some passages, Lakefront refers to the MS28-3 Substation Project located on Ontario Street in Coburg. In other passages, Lakefront describes a substation at Victoria Street. Are these two ways of identifying the same substation, or are they different substations?

LUI Response:

MS28-3 is located on Ontario Street in Cobourg. Any reference to MS28-3 being located on Victoria Street is incorrect.

CCMBC-8
Reference: Financial Overview, page 55
Preamble: The total cost of the MS28-3 substation project is $2,535,311.

Questions:

a) What was the original cost estimate of the MS28-3 substation at the time of project approval prior to construction? Please file an itemized cost estimate that shows materials, LUI labour, contracted services, overheads and interest during construction.

LUI Response:

Estimate Type	Estimated Amount
Substation Quote	922,237
Design & Build Quote	1,368,000
Total	2,290,237

b) Please file a table showing actual cost of the substation showing materials, LUI labour, contracted services, overheads and interest during construction, explaining all variances with the amounts shown in response to question a) above.

LUI Response:

Actual Cost Type	Actual Amount
LUI Labour	54,224
LUI Material	47,636
Equipment & Subcontractors	2,433,450
Total	2,535,310

	Estimate	Actual	Difference
Substation, Design, & Construction	2,290,237	2,433,450	143,213
LUI Labour & Material	-	101,860	101,860
Total	2,290,237	2,535,310	245,073

Variances are due to original quote from contractors and equipment increasing and unaccounted for LUI inventory needs and material for the substation build as represented above.

c) Was the construction of the substation contracted out or was it performed by Lakefront Utilities employees?

LUI Response:

MS28-3 was substantially constructed under an EPC contract with KPC. LUI purchased the substation transformer, 27.6 kV switchgear and the station services transformer directly.

d) Considering that the substation was competed and placed in service in 2023, what will be the book value of the substation on January 1,2025?

LUI Response:

The book value as at January 1, 2025 will be $2,451,271.87.

CCMBC- 9
Reference: Page 57
Preamble: The Distribution System Code (DSC) outlines the conditions under which distributors may obtain contributions from developers to support system enhancement projects. Specifically, Section 3.2 of the DSC requires that when a distributor plans an expansion of its main distribution system, developers must make a capital contribution if the cost of the expansion and ongoing maintenance exceeds the projected incremental distribution revenue.

Questions:

a) Please file the calculation of the amount of the contribution, including all inputs and assumptions, that would be required from residential developers had LUI followed the current requirements of Appendix B of the Distribution System Code.

- A maximum customer connection horizon of five (5) years, calculated from the energization date of the facilities.

- A maximum customer revenue horizon of twenty five (25) years, calculated from the in service date of the new customers.

  LUI Response:
  The response to CCMBC-9 a) is in CCMBC-9 b).

b) Please file the calculation of the amount of the contribution, including all inputs and assumptions, if the requirements of Appendix B of the Distribution System Code are revised as proposed by the OEB in its notice of November 18, 2024.

- A maximum customer connection horizon of 15 years, calculated from the energization date of the facilities.

- A maximum customer revenue horizon of 40 years, calculated from the in service date of the new customers.

LUI Response:

It is challenging to provide precise calculations for developer contributions under the current and proposed Appendix B requirements of the Distribution System Code due to variations in input data, such as customer growth rates and revenue forecasts, as well as uncertainties in long-term infrastructure costs. However, including the transformer station in the rate base offers clear benefits. This approach ensures costs are distributed fairly, supports both immediate and future growth, and aligns with key regulatory and policy objectives.
The complexities involved in forecasting contributions based on varying customer connection and revenue horizons underscore the importance of adopting a proactive infrastructure strategy. By focusing on long-term system reliability and community benefits, the proposed inclusion in the rate base aligns with the spirit of the Distribution System Code while addressing current and future needs effectively.
Argument for Including the Transformer Station in the Rate Base
The inclusion of the new transformer station in the rate base now, rather than waiting for developers to assume costs over an extended period, is in the best interest of the current customer base. This decision ensures fair cost distribution, enhances service reliability, and supports regional growth, while aligning with key regulatory and policy objectives.

This decision is supported by several key considerations:

1. Supporting Current Customers' Immediate Needs

• Voltage Conversion Benefits: Approximately 5 MVA (15%) of the new station's capacity is dedicated to completing the transition from 4.16 kV to 27.6 kV. This modernization enhances efficiency, reduces losses, and improves reliability, directly benefiting current customers. The existing two 27.6 kV substations were operating at roughly 50% peak loading, meaning if one went out of service during a peak period, the other could handle 100% of the 27.6 kV load. This redundancy and reliability were key drivers of the new station's construction.

• Capacity Relief: The new station alleviates the immediate stress on the existing transformer station, ensuring that the needs of current customers are met without compromising service quality.

2. Fair and Equitable Cost Distribution

• Shared Responsibility: Including the station in the rate base now distributes costs equitably across all customers. This avoids disproportionately burdening future customers or developers and ensures that those who benefit contribute fairly.

• Minimizing Long-Term Costs: Delaying inclusion would result in accumulating financing costs, ultimately increasing the overall burden on customers. Early inclusion helps minimize borrowing and ensures a more stable recovery of costs.

3. Enabling Growth While Protecting Current Customers

• Strategic Capacity for Growth: The station's maximum design loading is 33 MVA, and its maximum planned loading is 26.6 MVA, ensuring sufficient headroom for future demands. Of the 33 MVA, 15% (5/33 MVA) is allocated to the 4.16 kV to 27.6 kV voltage conversion, while 85% (28/33 MVA) supports new load growth and redundancy. This ensures that development does not strain resources needed by current customers.

• Economic Development: Investments like this transformer station are foundational for attracting new residents and businesses, enabling regional growth and enhancing the community's economic vitality.

4. Broad Community Benefits

• Boosting Local Tax Revenue: By enabling housing and business growth, the new station indirectly increases the town's tax base, which can be allocated to community services such as schools, parks, and public transit, enhancing overall quality of life for residents. This additional revenue can be allocated to improving schools, parks, public transit, and other community services, enhancing overall quality of life for residents. This revenue supports investments in public services such as schools, parks, and transit infrastructure, benefiting the entire community.

• Job Creation and Economic Activity: New residents and businesses stimulated by the station's capacity contribute to local job creation and economic growth.

• Alignment with Municipal Planning: The station supports municipal objectives for residential and commercial expansion, ensuring the town remains an attractive location for development.

5. Addressing Infrastructure Funding Gaps

• No Access to Provincial Funding: Unlike municipalities, which receive provincial funding for infrastructure projects such as roads and water systems, local distribution companies (LDCs) must rely on rate recovery for infrastructure investments. Similar infrastructure projects, such as the expansion of municipal water systems, have faced significant funding challenges when provincial support was unavailable. These examples emphasize the importance of timely inclusion in the rate base to ensure financial viability and avoid delays in critical infrastructure development.
• Ensuring Financial Stability: By spreading costs across the existing customer base, the LDC avoids reliance on piecemeal developer contributions, which could delay recovery and create financial strain.

6. Alignment with Policy Objectives

• Supporting Provincial Growth Goals: The transformer station enables growth that aligns with Ontario’s A Place to Grow: Growth Plan for the Greater Golden Horseshoe, which emphasizes sustainable community development and intensification. Additionally, the province's push to accelerate the construction of new homes, driven by initiatives such as streamlining approval processes and increasing funding for affordable housing projects, highlights the urgent need for reliable electrical infrastructure to support housing expansion and meet growing demand.
• Complementing Public Investments: The station ensures that electrical infrastructure is ready to support municipal and provincial investments in housing, transit, and other public utilities.

7. Protecting Customers from Increased Costs

• Avoiding Inflationary Pressures: Since the station is already constructed, delaying cost recovery from future development adds an uncertain debt burden to the utility. Early inclusion in the rate base allows the project to be financed under current cost structures, reducing the risks of future rate increases and financial instability.
• Equity for New Customers: Including the station in the rate base now ensures that new customers contribute equitably through rates as they connect, avoiding disproportionate financial pressure on current customers.

8. Addressing Ontario Ministry of Energy Electricity Infrastructure Hardening and OEB LDC Infrastructure Requirements

• Infrastructure Hardening: The transformer station's inclusion strengthens the local electricity grid's resilience against extreme weather events and potential disruptions, aligning with the Ontario Ministry of Energy's goals for infrastructure hardening.
• Compliance with OEB Requirements: By proactively including the station in the rate base, the LDC demonstrates compliance with the Ontario Energy Board's infrastructure requirements, ensuring that the electrical system meets both current and future reliability standards.

• Long-Term System Reliability: Investments in infrastructure modernization through projects like this ensure that the grid remains robust, reliable, and capable of supporting future technological advancements and energy needs.

In conclusion, adding the new transformer station to the rate base is a strategic move that ensures fair cost distribution, enhances service reliability, and supports economic and regional growth. By addressing funding gaps and aligning with provincial and municipal planning objectives, this decision effectively balances the immediate needs of current customers with long-term community benefits. This decision ensures reliable service, fair cost distribution, and robust support for regional economic growth. By aligning with provincial and municipal planning goals and addressing funding challenges proactively, this approach delivers significant value to all stakeholders. It ensures reliability, promotes equitable cost distribution, supports local growth, and aligns with provincial and municipal planning objectives. By proactively addressing funding gaps and supporting infrastructure modernization, this approach provides significant operational and economic value to customers and the broader community.

CCMBC-10
Reference: Table 8: Bill Impacts by Rate Class - 28 kVA Victoria Street Substation. Page 60

Questions:

a) Does the column with the title "January 1/2024 Rates" show rates that include the costs of the Victoria Street Substation? If the answer is yes, please file a revised table that does not include the costs of the Victoria Street Substation.

LUI Response:

The “Jan 1/2024 Rates” column does not show costs of the Victoria Street Substation.

b) Please explain why the rates for the Residential, the Sentinel and the Street Lighting rate classes increasing from January 1/2024 to January 1/2025 while the rates of other rate classes are decreasing.

LUI Response:

The increase in rates for the Sentinel and Street Lighting classes from January 1, 2024, to January 1, 2025, is due to the small distribution of rates and volumes in these classes, which is typical seen in the rate generator model. For Residential customers, rates are actually decreasing, not increasing. The apparent increase in other rate classes is likely due to the smaller customer base in those categories, which results in a higher allocation of fixed costs. This explains the rate changes, reflecting cost recovery needs rather than overall increases for all classes.

VECC-1

Ref: Manager’s Summary p. 47

The evidence states “At the time the 2022-2026 Distribution System Plan (DSP) was developed and presented during the 2022 Cost of Service (COS) proceeding, Lakefront Utilities Inc. (LUI) did not anticipate needing the Victoria Street Transformer Station within the five-year Incentive Regulation Mechanism (IRM) period, and thus did not claim an Advanced Capital Module (ACM). The necessity to construct and commission the station by the end of 2023 became apparent later due to emerging technical management challenges and significant system concerns that escalated the urgency of this investment.

a) Please provide the date the need to construct the station became apparent and provide more details on the initial driver(s) that drove this need.

LUI Response:

The date that the need to construct the station became apparent was upon receipt of the initial draft of Lakefront's Station Capacity Study by Raven Engineering on October 9, 2020. See VECC-2 response for Station Capacity Study documentation. There were three main drivers for the construction of the station: 1) Load growth, 2) 4.16 kV to 27.6 kV conversion, 3) Reliability/Redundancy.

b) Please provide internal correspondence regarding final approval of the project.

LUI Response:

From: Dereck Paul
Sent: Friday, October 14, 2022 12:33 PM
To: [redacted]
Cc: [redacted]
Subject: Lakefront Utilities awards KPC New 44/27.6 kV Ontario Substation MS28.3

Good afternoon [redacted]

Congratulations again on being awarded the Engineering, Procurement and Construction (EPC) of Lakefront Utilities Inc. new 20/26/33 MVA 44-27.6 kV Substation.
[redacted]

Please find attached a copy of Purchase Order #PO02203 dated Oct/13/2022 referencing a copy of Specification 2202-01 EPC – 44/27.6 kV Substation and KPC's price bid form (RFP New Substation MS28-3).
Also attached is a LUI Letter of Agreement which I've signed that requires the standard documentation as discussed with [redacted] i.e. insurance including Lakefront Utilities Inc. as an additional insured, WSIB coverage for all employees and contractors, Non-Disclosure 3rd Party and Sub-Contractors Agreements and the standard indemnification. I've also attached our OHSA contractor safety qualifications form to be completed. Please sign and return the "LUI Letter of Agreement" and provide the other documentation at your convenience so we can arrange a follow up meeting to discuss next steps.

[redacted]

c) Please provide the scope of the project including the equipment to be installed.

LUI Response:

See LUI's Substation Specification documentation prepared by Raven Engineering in VECC-2. The scope for the station is included in the document.

VECC-2

Ref: EB-2021-0039 Exhibit 2 Appendix B DSP p. 71

At page 71, the DSP states "Steady load growth in Cobourg and Cramahe is expected in the forecast period. This results in the system load capacity approaching the maximum allowance and requires additional capacity to accommodate future connections. The station capacity study is attached as Appendix A.

Please provide a copy of Appendix A.

LUI Response:

See "Station Capacity Study" document.

RAVEN ENGINEERING INC.

6251 O'Neil St., Unit 2
Niagara Falls, ON
L2J 1M6
905-357-4413

Station Capacity Study

Town of Cobourg

Prepared for

Lakefront Utilities Inc.

Rev 0

RAVEN ENGINEERING INC.

6251 O’Neil St., Unit 2
Niagara Falls, ON
L2J 1M6
905-357-4413

Revisions		
No.	Date	Description
A	2020-10-09	Issued for client review
B	2020-11-18	Issued for client review
0	2020-12-15	Issued final

Prepared by

Mitchel Brown, EIT

Reviewed by

Andrew Durward, P.Eng.

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Appendix B - Underground System Calculations

1.0 Executive Summary

This study was initiated to review the capacity of the existing 44/27.6 kV substations in the Town of Cobourg and to determine the timing of additional capacity requirements to meet forecast load growth, new developments and the impact of 4kV voltage conversion.

The substations are currently operating at capacity to meet summer peak load under contingency conditions. Additional capacity is required to meet existing and future loads. Some immediate capacity can be created for 2021 by replacing substation cables at MS28-2. Deferring voltage conversion plans will provide time to construct a new 20/32 MVA substation by 2023 which will allow the system to meet projected load growth under contingency condition.

Recommendations for providing increased capacity are included.

2.0 Background

2.1. Supply to the Town of Cobourg

The Town of Cobourg is normally supplied by two 44 kV feeders (M2 & M4) from the Hydro One Port Hope Transformer Station, located 3.7km west of the Town boundary. A third feeder (M17) provides backup supply during contingency conditions.

The 44kV system supplies two 44/27.6kV substations, three 44/4.16kV substations and large commercial and industrial customers.

The majority of new developments are supplied at 27.6kV, causing projected load growth on the two 44/27.6kV substations. A multi-year voltage conversion program is replacing the 4.16kV distribution with 27.6kV distribution, which will further increase the load on the 27.6kV system.

3.0 MS28-1 Victoria Substation (44/27.6kV)

3.1. Description

Located at 28 Victoria St., this station was built in 1990 and has a single 20 MVA transformer supplying an indoor metal-clad switchgear.

The transformer was built in 1990 and is currently 30 years old. Maintenance records show elevated levels of combustible gases in the oil. The gas levels have been relatively constant since 2013.

The station supplies two 27.6kV feeders, F1 and F2.

The relays were replaced in 2011 and the circuit breakers were replaced in 2016.

The station is monitored by SCADA.

3.2. Capacity

The station is supplied from the 44kV feeder by 556mcm AAC conductor and a 1200 amp load break switch.

The 44kV circuit switcher is rated 1200 amps continuous.

The circuit switcher is connected on both sides with 1.25" Al bus.

The transformer nameplate shows a provisional 20/26.6/33.3 MVA rating "when equipped by approved fans". The transformer was retrofitted with fans to provide forced cooling, but the fans are not approved by the manufacturer. A conservative approach would be to consider the fan cooled rating 26.6 MVA.

The transformer secondary cables are parallel 250mcm Cu, installed in 4" ducts, two cables per duct.

The station device capacities are listed in Table 1. The limiting factor for station capacity is the transformer, with a rating of 26.6 MVA.

3.3. Feeders

The feeder breakers are rated for 1250 amps, and the feeder exit cables are 750mcm Al in duct, rated for 428 amps.

The operating limit for the feeders can be conservatively set at 400 amps per feeder.

3.4. Provisions for Expansion

There is provision for a third feeder (F3) consisting of a breaker cell only. There is no F3 breaker, relaying or controls.

The station property is quite large and includes pole and transformer storage for the utility, as well as a water tower. There is adequate room for an additional transformer and metal-clad switchgear. Multiple feeder egress routes are available.

Device	Details	Voltage	Ampacity	Capacity (MVA)
Primary Leads	556 Al	44 kV	680 A[1]	51.8
Primary Switch	N/A	44 kV	600 A	45.7
Circuit Switcher	S&C Series 2000	44kV	1200 A	91.4
Primary Bus	1.25" Ø Alum. Bus	44 kV	859 A[2]	65.4
Transformer	FLA @ 26.6 MVA	44 kV	349 A	26.6*
Transformer	FLA @ 26.6 MVA	27.6 kV	556 A	26.6*
Secondary Cables	250mcm Cu (x2)	27.6 kV	279 A[3](x2)	26.6*
Main Breaker	ABB PowerBloc	27.6 kV	1250 A	59.7
Feeder Cable	750mcm Al	27.6 kV	428 A[4]	20.5 (x2)
Station Capacity				**26.6**

* - Capacity limiting element

<u>Table 1 – MS28-1 Device Capacity</u>

[1] Standard Handbook for Electrical Engineers, Table 4-23
[2] AFL Bus Conductors, Physical & Electrical Properties of Aluminum, Pg. 617
[3] Underground System Calculation, MS28-1 Secondary
[4] Ontario Electrical Safety Code, Table D17C

4.0 MS28-2 Brook Rd. Substation (44/27.6kV)

4.1. Description

Located at 883 Brook Rd. N., this station was built in 1996, and has a single 20/26/32 MVA transformer supplying indoor metal-clad switchgear.

The transformer was installed in 2014 and is 6 years old. It replaced a failed 15/20/25 MVA unit.

The station supplies two 27.6kV feeders, F4 and F6.

The relays were replaced in 2011.

The station is monitored by SCADA.

4.2. Capacity

The station primary cables are #4/0 Cu, installed in direct buried 4” ducts, one cable per duct.

The 44kV circuit switcher is rated 1200 amps continuous.

The circuit switcher supplies the transformer with #2/0 Cu bare conductor.

The transformer is equipped with manufacturer installed fans and is rated for 20/26/32 MVA.

The transformer secondary cables are 1000mcm Cu, installed in direct buried 4” ducts, one cable per duct.

The station device capacities are listed in Table 2. The limiting factors for station capacity are the #4/0 primary cables, with a rating of 26.6 MVA and the overhead leads to the riser pole load break switch, with a rating of 27.4 MVA.

4.3. Feeders

The feeder breakers are rated for 1250 amps, and the feeder exit cables are 750mcm Al in duct, rated for 428 amps.

The operating limit for the feeders can be conservatively set at 400 amps per feeder.

4.4. Provisions for Expansion

There is a spare feeder position (F5) equipped with controls and protective relaying.

The size of the property is not known at this time.

Device	Details	Voltage	Ampacity	Capacity (MVA)
Primary leads	#2/0 Cu	44 kV	360 A[5]	27.4*
Primary Switch	N/A	44kV	600 A	45.7
Primary Cables	#4/0 Cu	44 kV	306 A[6]	23.3*
Circuit Switcher	S&C Series 2000	44kV	1200 A	91.4
Transformer	FLA @ 32 MVA	44 kV	420 A	32.0
Transformer	FLA @ 32 MVA	27.6 kV	670 A	32.0
Secondary Cables	1000mcm Cu	27.6 kV	746 A[7]	35.6
Main Breaker	Merlin Gerlin FG3	27.6 kV	1250 A	59.7
Feeder Cable	750mcm Al	27.6 kV	428 A[8]	20.5 (x2)
Station Capacity				**23.3**
* - Capacity limiting element				

Table 2 – MS28-2 Device Capacity

[5] Standard Handbook for Electrical Engineers, Table 4-27
[6] Ontario Electric Safety Code, Table D17C
[7] Underground System Calculation, MS28-2 Secondary
[8] Ontario Electric Safety Code, Table D17C

5.0 Station Load Forecasts

The station load forecast was developed using the following inputs:

a.) Existing load escalated by percent growth,

b.) Planned developments with estimated load, and

c.) Voltage Conversion program.

5.1. Source Data

The following source data was used:

a.) Historic loads from SCADA,

b.) Load Forecast Study prepared for Lakefront Utilities, Rev 0, Sept. 29, 2020, and

c.) Planned Voltage Conversion schedule.

5.2. Existing Loads

Summer peak load for the utility occurred on August 24, 2020 at 17:00. The 27.6kV total station load at this time was 21.5 MVA.

Station / Feeder	Feeder Load (MVA)	Station Load (MVA)
MS28-1		
F1	9.0	-
F2	6.8	-
Station Total	-	15.7
MS28-2		
F4	3.2	-
F6	2.6	-
Station Total	-	5.8
28kV Total		**21.5**

Table 3 – MS28-1 Existing Loads - System Peak 2020-08-24 17:00

SCADA historical load for the 27.6kV combined station total occurred on July 27, 2020 at 18:00. At this time all of the load was on MS28-2 due to an equipment failure at MS28-1.

Station / Feeder	Feeder Load (MVA)	Station Load (MVA)
MS28-1		
F1	0.0	
F2	0.0	
Station Total		0.0
MS28-2		
F4	15.2	
F6	10.3	
Station Total		25.8
28kV Total		**25.8**

Table 4 – MS28-1 Existing Loads – Station Peak 2020-07-27 17:00

5.3. Load Growth

Load growth was estimated using a 0.5% annual growth rate as per the 2020 Load Forecast Study.

5.4. Planned Developments

The 2020 Load Forecast Study listed the planned developments and their estimated load. The development loads were allocated to feeders and stations based on the existing supply feeder to their location. Where development in-service dates cover more than one year, the load forecast is equally distributed over the in-service time period. A 95% power factor was assumed.

ID	Name	Load (kVA)	Station	Feeder	Timing
1.	DePalma Hotel	215	MS28-1	F1	2021 – 2022
2.	Vandyk CTC Lands	132	MS28-1	F1	2021 – 2025
3.	1111 Elgin St. W.	24	MS28-1	F1	2021 – 2022
4.	Nickerson Woods	42	MS28-2	F4	2021 – 2025
5.	Rondeau Estate	2,763	MS28-2	F4	2021 – 2030
6.	Balder Corp.	130	MS28-1	F1	2021 – 2022
7.	Mason Homes	49	MS28-2	F6	2021 – 2025
8.	East Village Phase 5	615	MS28-2	F6	2021 – 2030
	Total	**3,970**	**(3.970 MVA at 95% pf)**		

Table 5 – Planned Developments

5.5. Voltage Conversion

The voltage conversion program will transfer all of the remaining 4.16kV load to the 27.6kV system. Existing 4.16kV feeder loads were obtained from SCADA historical data.

Feeder	Load (MVA)	Timing
Kerr F19	1.671	2021
D'Arcy F9	0.701	2022
Orr F13	1.307	2024
Orr F14	2.010	2024
Total	**5.689**	**-**

Table 6 – Voltage Conversion

6.0 Adequacy of Existing Facilities

The adequacy of station capacity can be determined by plotting the load forecast against the station planning capacity. Figure 1 shows the total 28kV station load plotted against the substation capacity.

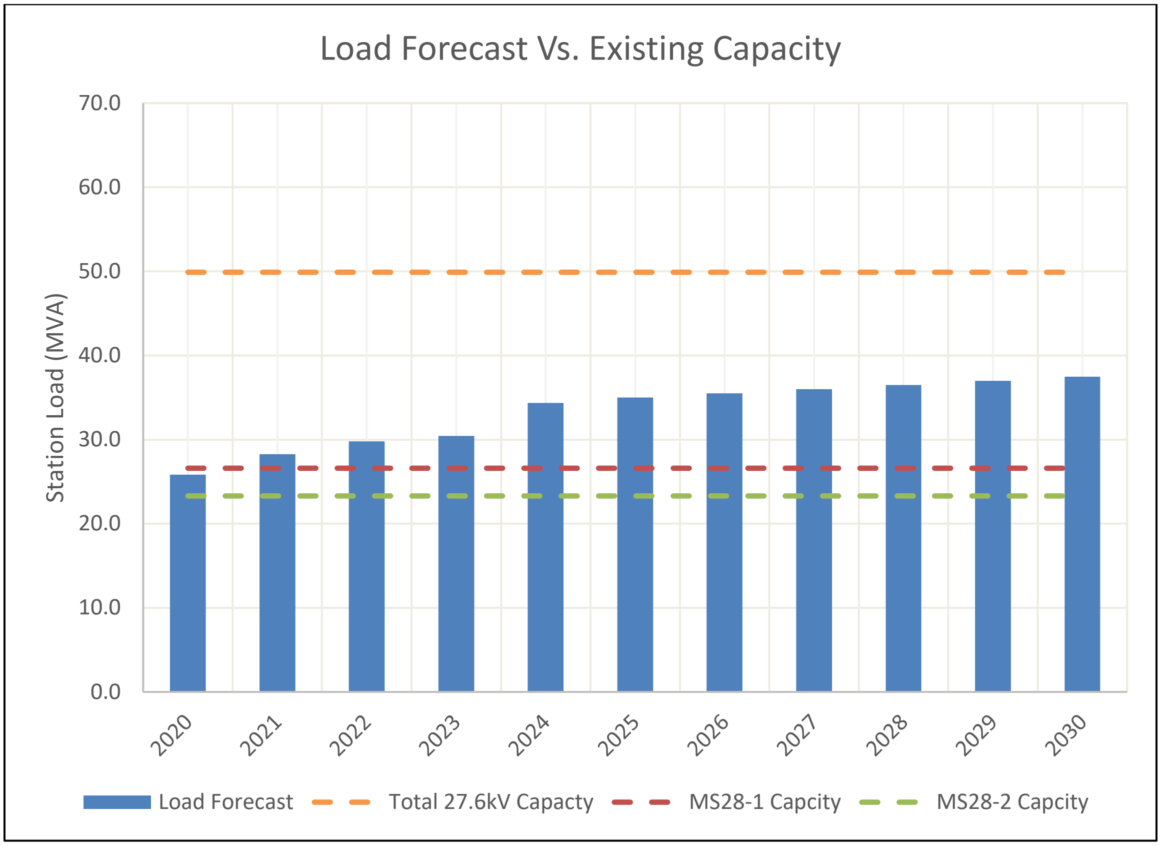


Figure 1: Projected 28kV Load vs. Existing Station Capacity

From the graph it can be seen that the existing facilities are inadequate to supply peak load during the contingency of loss of one station. Anticipated load growth, new connections and voltage conversion will make this situation worse until additional capacity can be brought on line.

7.0 Options for Capacity Relief

There are several options for station capacity relief.

7.1. MS28-2 (Brook) Transformer Cable Upgrade

The station is currently limited below the transformer nameplate capacity by the primary and the overhead leads from the circuit switcher to the transformer. Replacing these cables and conductors with higher rated equipment would increase the station capacity to 32 MVA, providing an additional 8.7 MVA of capacity.

7.2. MS28-1 Feeder F3

The existing two feeders provide up to 40 MVA of capacity, which is more than the station can supply with all elements in service. However, under contingency conditions with the loss of one feeder, the station is limited to 20 MVA.

Adding the F3 feeder would require:

a.) A new circuit breaker, equipped with protection and controls,

b.) New feeder exit cables, and

c.) Overhead feeder egress from the station.

The existing F1 and F2 feeders would be reconfigured as three feeders.

7.3. MS28-1 Transformer Upgrade

The station transformer is 30 years old and is smaller than the MS28-2 transformer. Its capacity is limited by the lack of manufacturer designed and installed cooling fans.

Replacing this transformer with a 20/26/32 MVA unit to match the MS28-2 unit would provide an additional 5.4 MVA of capacity.

7.4. MS28-1 Second Transformer and Metal-Clad Switchgear

This option includes the installation of a third 44/27.6kV substation transformer with associated metal-clad switchgear and feeder exits.

The transformer would be sized at 20/26/32 MVA to match the existing MS28-2 transformer, and the station would have a design capacity of 32 MVA.

The metal-clad switchgear would include a main breaker and three feeder breakers, similar to the existing two stations.

The 44kV system could be reconfigured to provide a normal open point between the M2 and M4 feeders at the MS28-1 location. With the addition of two 44 kV gang operated load break switches, the combined station load could be split between the two feeders, or supplied by either feeder, providing reliability improvements and operational flexibility.

7.5. MS28-2 Feeder F5

The existing two feeders provide up to 40 MVA of capacity, which is more than the station can supply with all elements in service. However, under contingency conditions with the loss of one feeder, the station is limited to 20 MVA.

Adding the F5 feeder would require:

a.) A new circuit breaker,

b.) New feeder exit cables, and

c.) Overhead feeder egress from the station.

The existing F4 and F6 feeders would be reconfigured as three feeders.

7.6. Contingency Analysis

A contingency analysis is recommended to review the various options for capacity relief.

The following contingencies should not result in a permanent loss of customer load:

a.) Loss of any one feeder,

b.) Loss of any one substation transformer or bus, and

c.) Loss of one 44kV supply feeder.

8.0 Recommendations

The following capital upgrades are recommended to provide adequate 27.6kV capacity to supply peak forecasted loads under contingency conditions. These recommendations are shown in Figure 2.

8.1. Upgrade the MS28-2 transformer primary cables to 750mcm Cu and primary drop leads to 350mcm to increase capacity to 32.0 MVA. This could be accomplished before 2021 summer peak loads.

8.2. Construct a new 44/27.6kV 20/32 MVA substation. This could be accomplished before 2023 summer peak loads.

8.3. Defer voltage conversion until after the new transformer station is constructed in 2023.

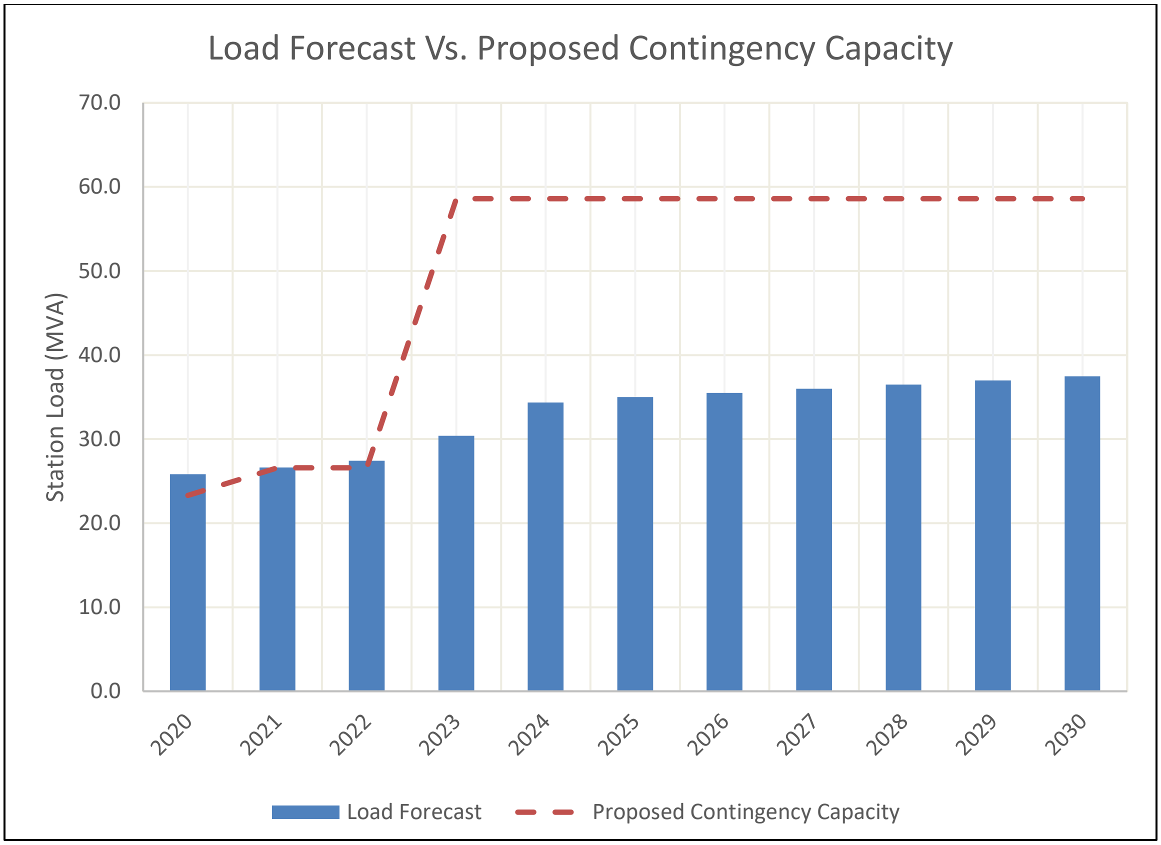
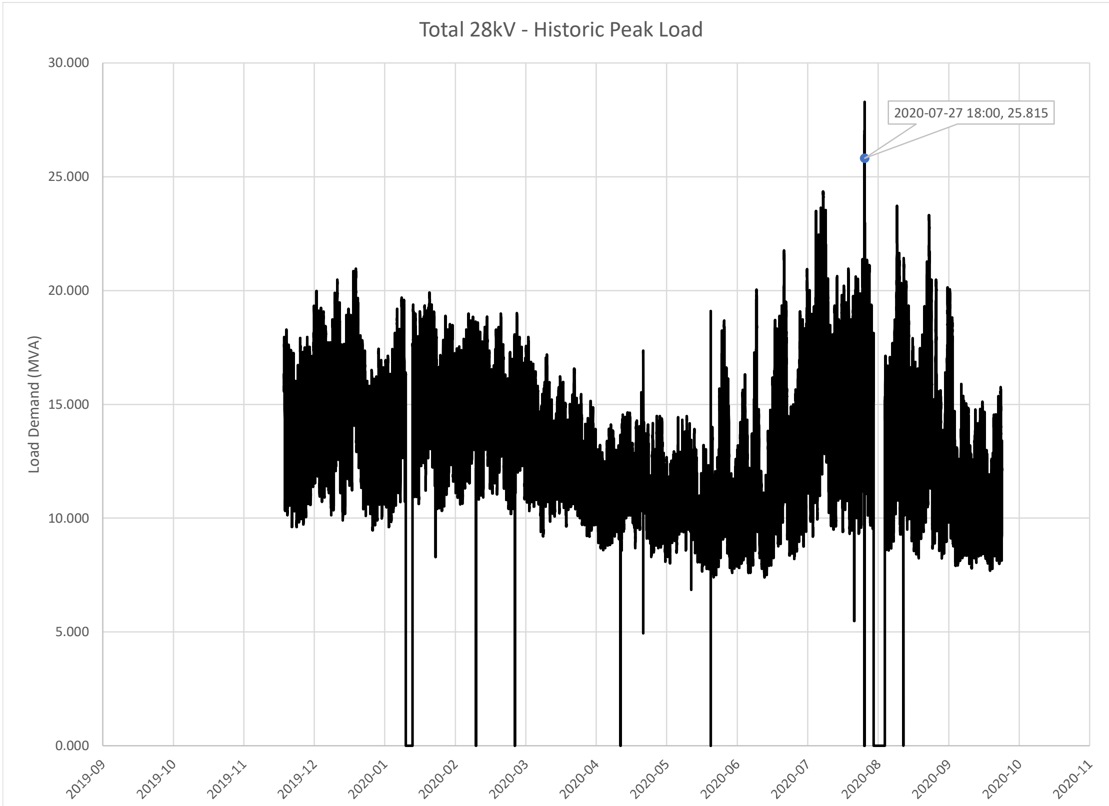


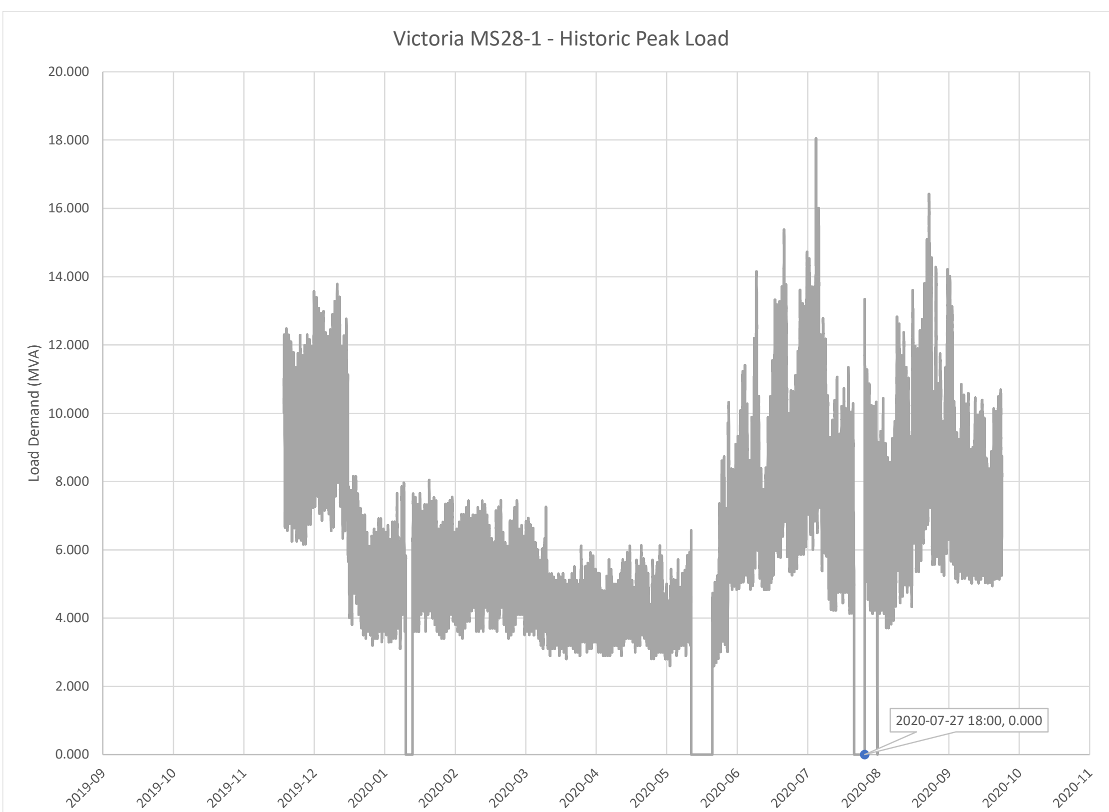
Figure 2: Projected 28kV Load vs Proposed Contingency Capacity

Appendix A - Historic Peak Load Graphs

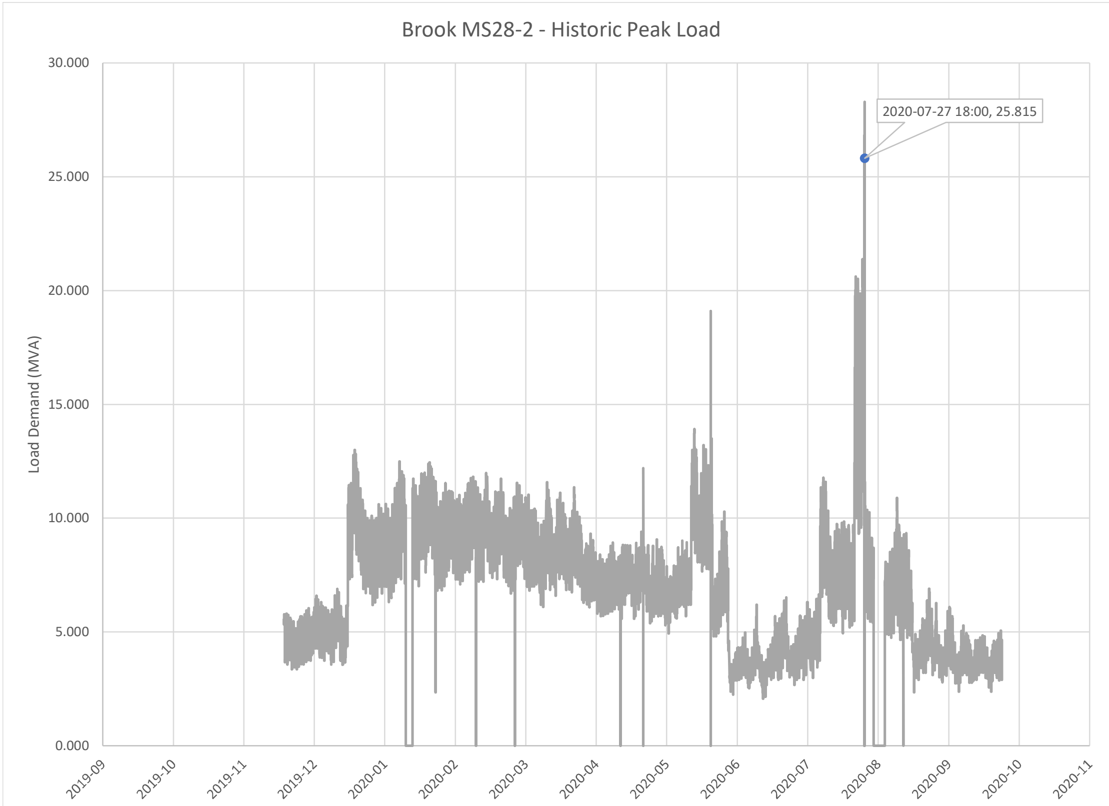
(Attached)

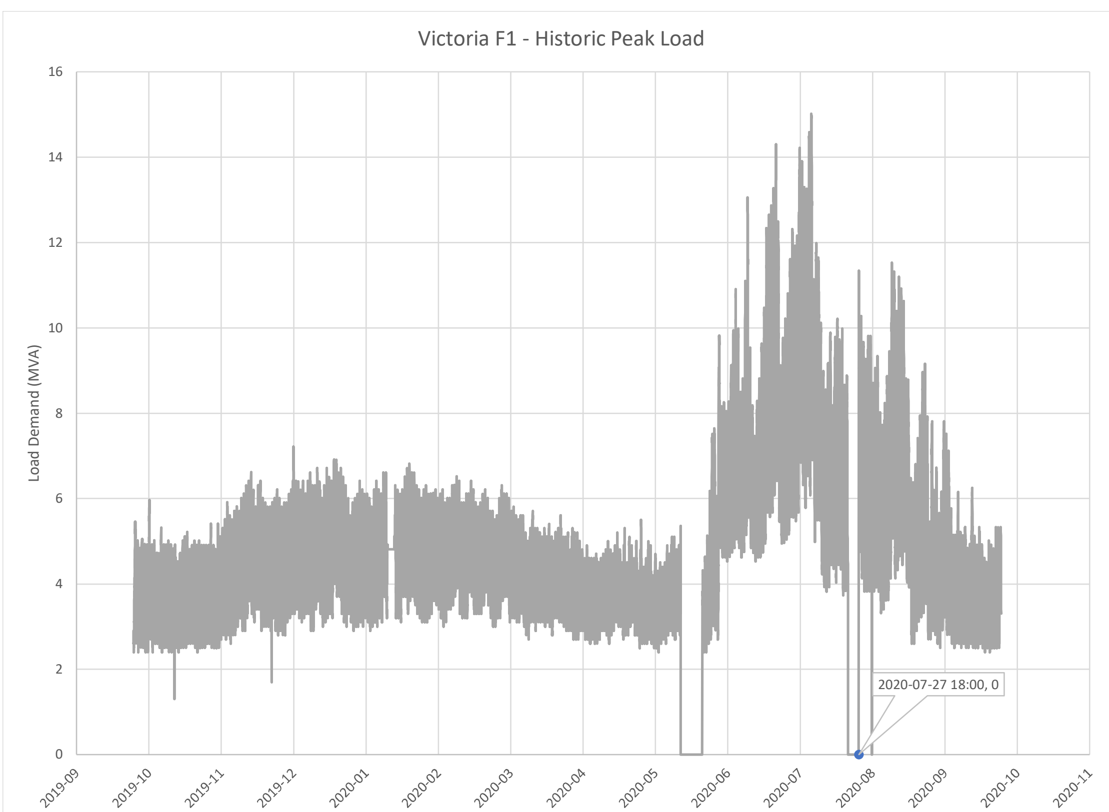


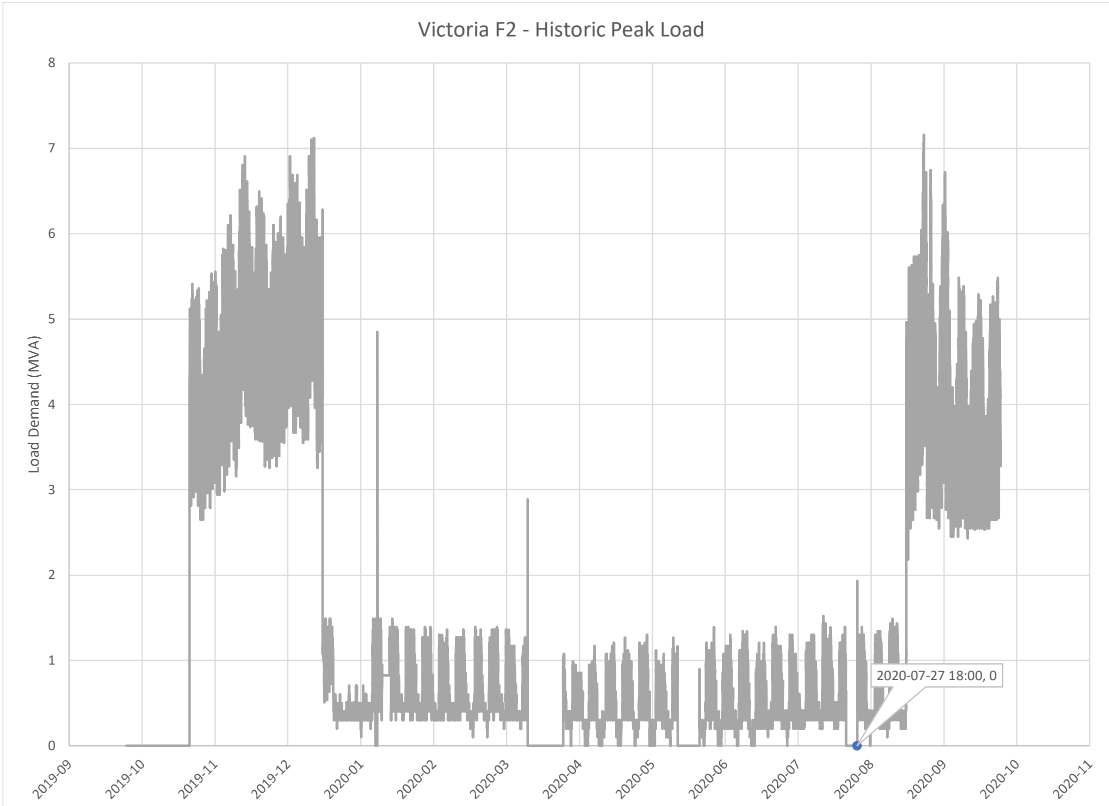
Total 28kV - Historic Peak Load
2020-07-27 18:00, 25.815
Load Demand (MVA)
30.000
25.000
20.000
15.000
10.000
5.000
0.000
2019-09
2019-10
2019-11
2019-12
2020-01
2020-02
2020-03
2020-04
2020-05
2020-06
2020-07
2020-08
2020-09
2020-10
2020-11



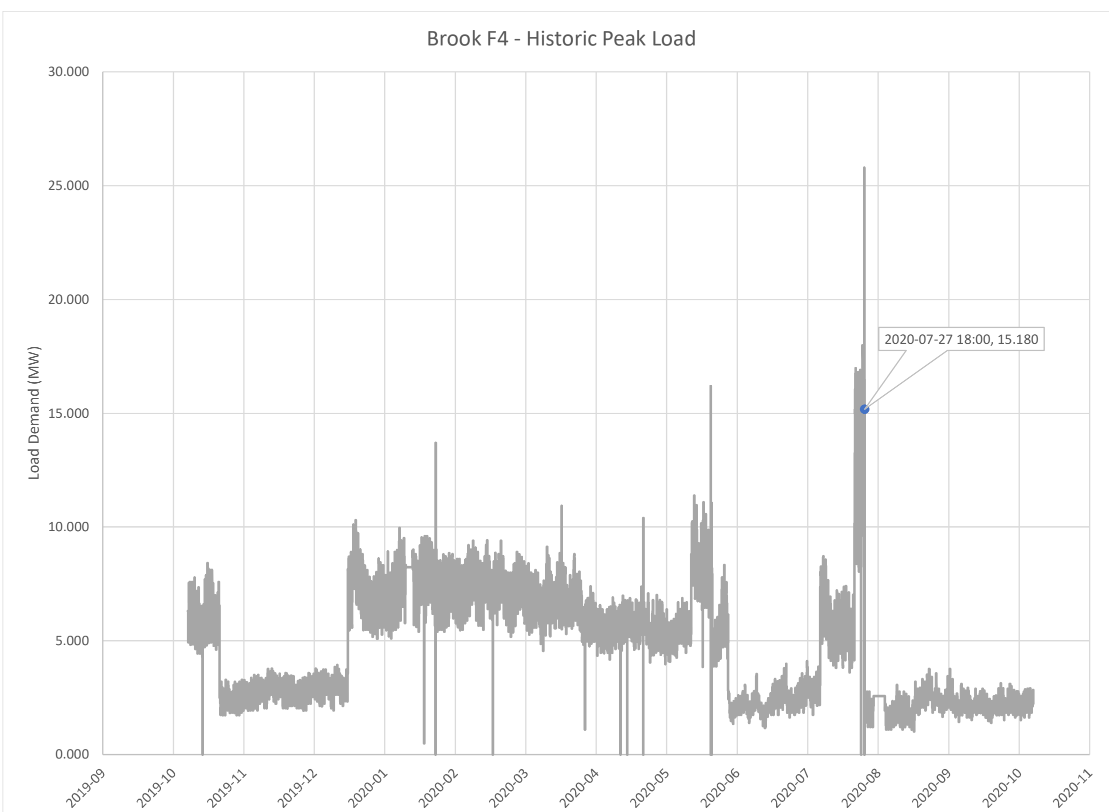
Victoria MS28-1 - Historic Peak Load
2020-07-27 18:00, 0.000
Load Demand (MVA)
20.000
18.000
16.000
14.000
12.000
10.000
8.000
6.000
4.000
2.000
0.000
2019-09
2019-10
2019-11
2019-12
2020-01
2020-02
2020-03
2020-04
2020-05
2020-06
2020-07
2020-08
2020-09
2020-10
2020-11


Brook MS28-2 - Historic Peak Load
Load Demand (MVA)
2020-07-27 18:00, 25.815
30.000
25.000
20.000
15.000
10.000
5.000
0.000
2019-09
2019-10
2019-11
2019-12
2020-01
2020-02
2020-03
2020-04
2020-05
2020-06
2020-07
2020-08
2020-09
2020-10
2020-11

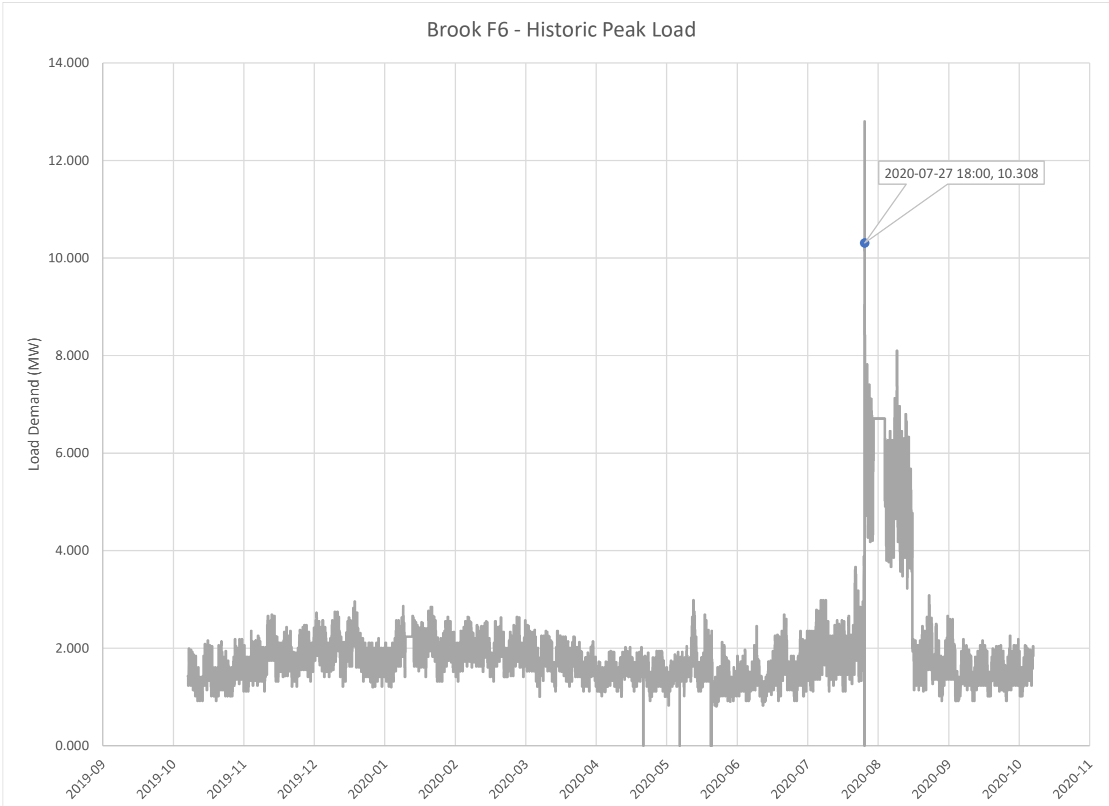

Victoria F1 - Historic Peak Load
Load Demand (MVA)
2020-07-27 18:00, 0
16
14
12
10
8
6
4
2
0
2019-09
2019-10
2019-11
2019-12
2020-01
2020-02
2020-03
2020-04
2020-05
2020-06
2020-07
2020-08
2020-09
2020-10
2020-11

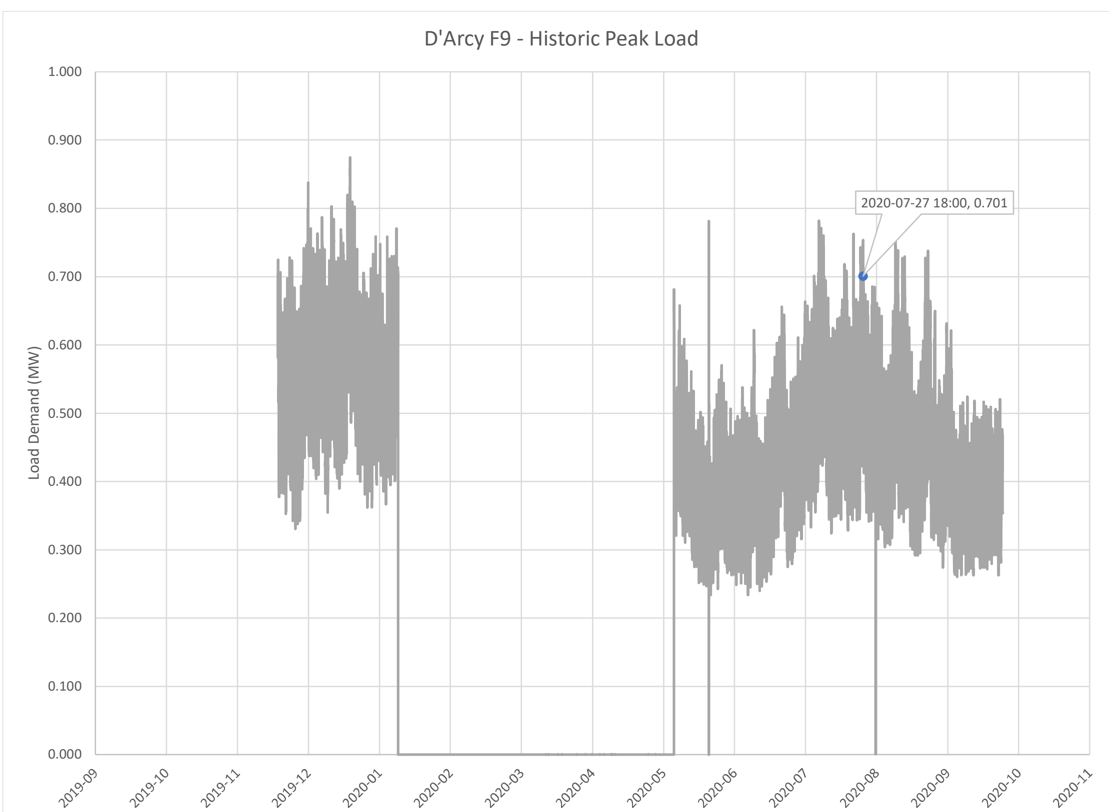


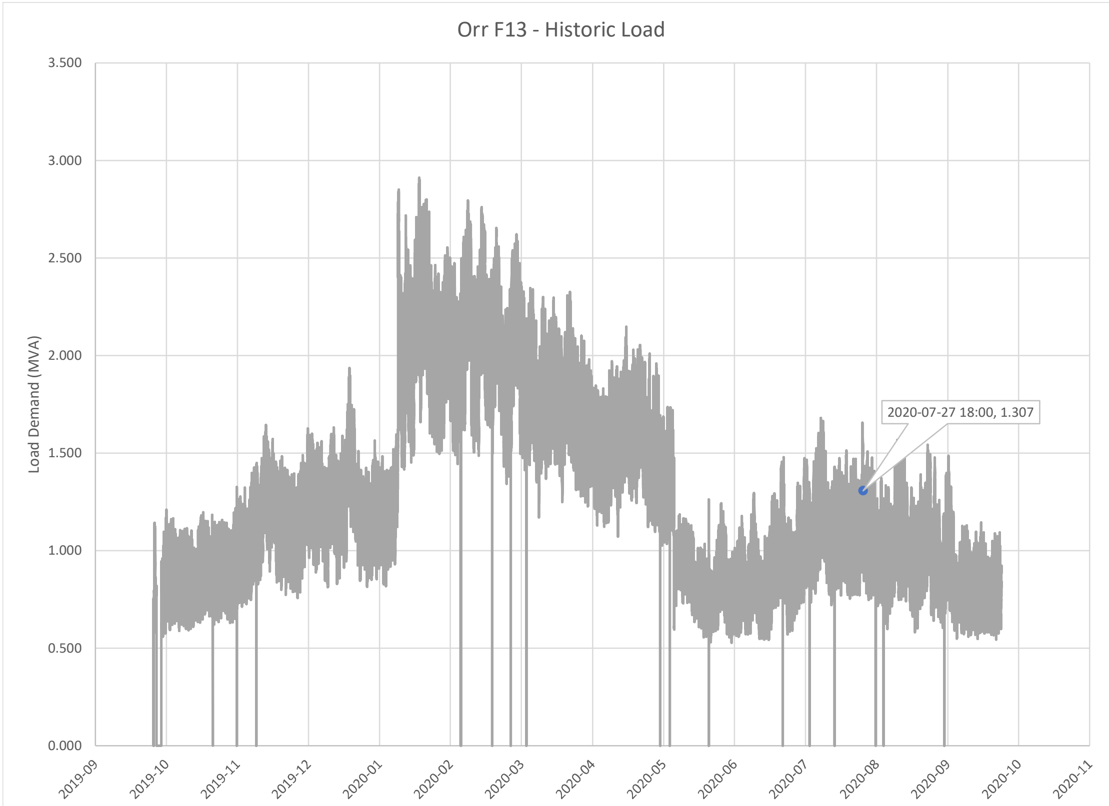
Victoria F2 - Historic Peak Load
Load Demand (MVA)
0
1
2
3
4
5
6
7
8
2019-09
2019-10
2019-11
2019-12
2020-01
2020-02
2020-03
2020-04
2020-05
2020-06
2020-07
2020-08
2020-09
2020-10
2020-11
2020-07-27 18:00, 0

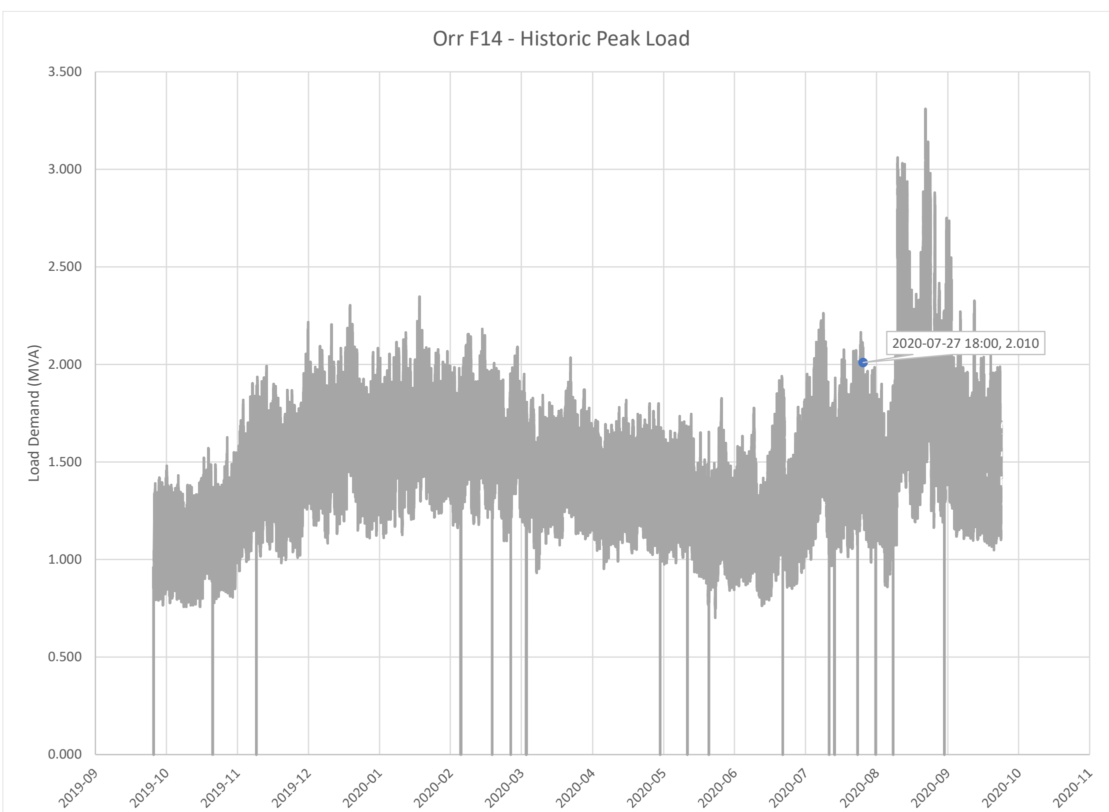


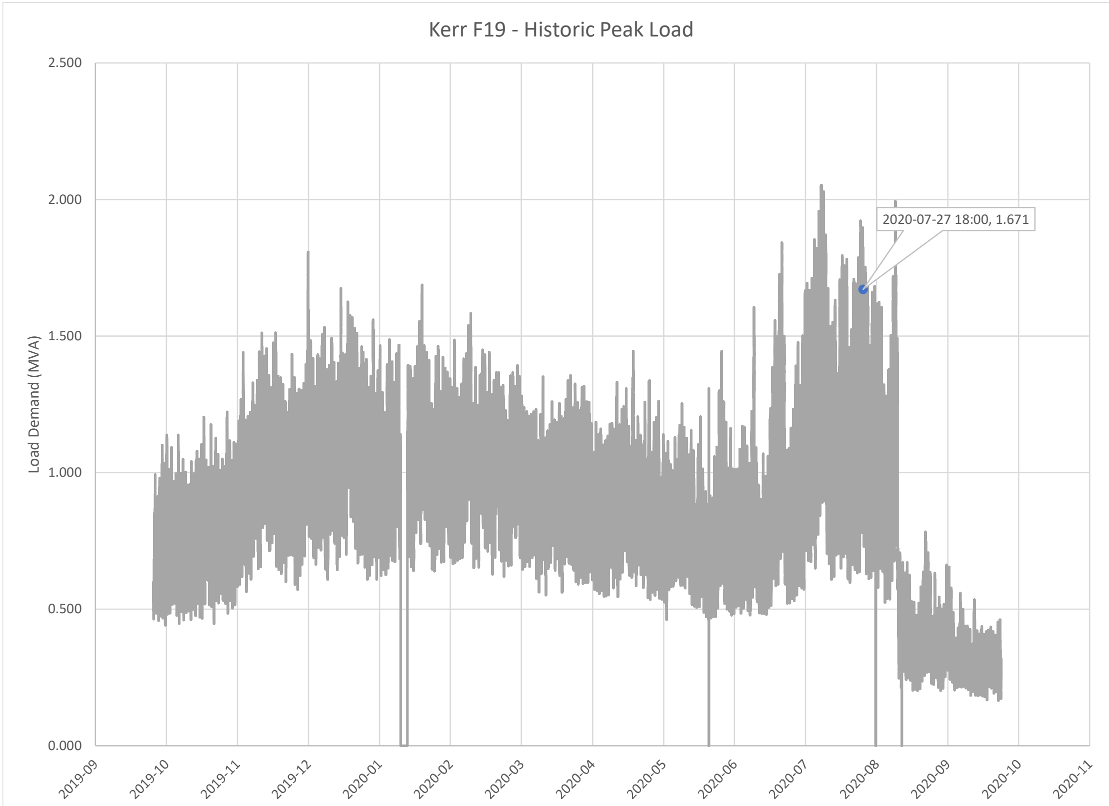
Brook F4 - Historic Peak Load
Load Demand (MW)
0.000
5.000
10.000
15.000
20.000
25.000
30.000
2019-09
2019-10
2019-11
2019-12
2020-01
2020-02
2020-03
2020-04
2020-05
2020-06
2020-07
2020-08
2020-09
2020-10
2020-11
2020-07-27 18:00, 15.180


Brook F6 - Historic Peak Load
Load Demand (MW)
14.000
12.000
10.000
8.000
6.000
4.000
2.000
0.000
2020-07-27 18:00, 10.308
2019-09
2019-10
2019-11
2019-12
2020-01
2020-02
2020-03
2020-04
2020-05
2020-06
2020-07
2020-08
2020-09
2020-10
2020-11


D'Arcy F9 - Historic Peak Load
Load Demand (MW)
1.000
0.900
0.800
0.700
0.600
0.500
0.400
0.300
0.200
0.100
0.000
2020-07-27 18:00, 0.701
2019-09
2019-10
2019-11
2019-12
2020-01
2020-02
2020-03
2020-04
2020-05
2020-06
2020-07
2020-08
2020-09
2020-10
2020-11


Orr F13 - Historic Load
Load Demand (MVA)
3.500
3.000
2.500
2.000
1.500
1.000
0.500
0.000
2019-09
2019-10
2019-11
2019-12
2020-01
2020-02
2020-03
2020-04
2020-05
2020-06
2020-07
2020-08
2020-09
2020-10
2020-11
2020-07-27 18:00, 1.307


Orr F14 - Historic Peak Load
Load Demand (MVA)
3.500
3.000
2.500
2.000
1.500
1.000
0.500
0.000
2019-09
2019-10
2019-11
2019-12
2020-01
2020-02
2020-03
2020-04
2020-05
2020-06
2020-07
2020-08
2020-09
2020-10
2020-11
2020-07-27 18:00, 2.010


Kerr F19 - Historic Peak Load
2.500
2.000
1.500
1.000
0.500
0.000
Load Demand (MVA)
2020-07-27 18:00, 1.671
2019-09
2019-10
2019-11
2019-12
2020-01
2020-02
2020-03
2020-04
2020-05
2020-06
2020-07
2020-08
2020-09
2020-10
2020-11

Appendix B - Underground System Calculations

(Attached)

Electrical Transient Analyzer Program

Underground Cable Raceway Systems

Ampacity Optimization Analysis - Uniform Ampacity

Method: Neher-McGrath

U/G System ID	Number of Cable Raceways	Number of Ext. Heat Sources
MS28-1 Secondary	1	0

Soil			Temperature Limits	
Type	RHO °C-cm/Watt	Ambient Temperature °C	Alarm °C	Warning °C
Average Dry	120.0	20.0	90.0	88.0

Multiplying Factors (MF)

Application MF: Not Considered

Individual Growth Factor: Not Considered

Global Growth Factor: 100 %

Output File: Y:\Lakefront\203110\ETAP\203110\MS28-1 Sec Cable.CD1S

Underground Cable Raceway Systems (RW2)

Duct Bank Raceway Data:

	Reference Distance		Dimension		Fill		Number	Number	Average Distance
	Horizontal	Vertical	Height	Width		RHO	of	of	Center-to-Center
ID	cm	cm	cm	cm	Type	°C-cm/Watt	Conduits	Cables	cm
RW2	100.00	58.50	72.00	152.00	Light Aggregate	120.0	3	2	19.00

Conduit Data:

	Reference Distance			Size	Thickness	OD	RHO	Thermal R	Fill
	Horizontal	Vertical							
ID	cm	cm	Type	mm	cm	cm	°C-cm/Watt	Ohm-m	%
Cond4	57.05	36.00	PVC__40	91	0.574	10.160	600.0	0.374	39.16
Cond5	76.05	36.00	PVC__40	91	0.574	10.160	600.0	0.374	39.16
Cond6	95.05	36.00	PVC__40	91	0.574	10.160	600.0	0.374	39.16

* Warning - Industry representatives recommend avoiding a jam ratio of 2.8 to 3.2.

\# Alarm - Cable jamming may occur when jam ratio is in between 2.74 and 2.8.

Cable Data:

		Rated	Current	Individual Growth Factor	Load Factor	Conductor				Insulation		
								Per			Thickness	Thermal R
ID	Size	kV	Amp	%	%	No.	Type	Phase	Construction	Type	mm	Ohm-m
MS28.1 T1 Sec Cable	250	35.000	0.00	100	100	1/C	CU	2	ConRnd-NT	EPR	9.1	0.525

	Shielding			Sheath	Armor	End	Jacket		Rdc	Outside
			Thickness					Thickness	@ 25°C	Diameter
ID	Status	Type	mm	Type	Type	Connection*	Type	mm	µOhm/m	cm
MS28.1 T1 Sec Cable	Yes	Copper	0.1			Open	PE	2.03	141.40	3.99

* End Connection is flagged as "Grounded" if any of the metallic layers (Shield/Sheath/Armor) is grounded at both ends.

Analysis Results (RW2)

No.	Cable ID	Conduit/Location ID	Conductor per Cable	Energized Conductor per Cable	Rdc @ Final Temp. µOhm/m	Dielectric Losses Watt/m	Yc	Ys	Conductor Losses Watt/m	Current Amp	Temp. °C
1	MS28.1 T1 Sec Cable-1A	Cond4	1	1	174.63	0.385	0.004	0.000	13.648	279.01	85.97
2	MS28.1 T1 Sec Cable-1B	Cond5	1	1	176.82	0.385	0.004	0.000	13.818	279.01	89.99
3	MS28.1 T1 Sec Cable-1C	Cond6	1	1	174.63	0.385	0.004	0.000	13.648	279.01	85.97
4	MS28.1 T1 Sec Cable-2A	Cond4	1	1	174.63	0.385	0.004	0.000	13.648	279.01	85.97
5	MS28.1 T1 Sec Cable-2B	Cond5	1	1	176.82	0.385	0.004	0.000	13.818	279.01	89.99
6	MS28.1 T1 Sec Cable-2C	Cond6	1	1	174.63	0.385	0.004	0.000	13.648	279.01	85.97

Yc = Increment of AC/DC resistance ratio due to AC current skin and proximity effect
Ys = Increment of AC/DC resistance ratio due to losses of circulation and eddy current effect in shield , sheath and armor

Summary (RW2)

No.	Cable ID	Conduit/Location ID	Size	Current Amp	Temp. °C
1	MS28.1 T1 Sec Cable-1A	Cond4	250	279.01	85.97
2	MS28.1 T1 Sec Cable-1B	Cond5	250	279.01	89.99 #
3	MS28.1 T1 Sec Cable-1C	Cond6	250	279.01	85.97
4	MS28.1 T1 Sec Cable-2A	Cond4	250	279.01	85.97
5	MS28.1 T1 Sec Cable-2B	Cond5	250	279.01	89.99 #
6	MS28.1 T1 Sec Cable-2C	Cond6	250	279.01	85.97

F Indicates fixed cable size in cable sizing calculations or fixed cable ampacity in uniform ampacity calculation
* Indicates a cable temperature exceeding its limit
# Indicates a cable temperature exceeding its marginal limit

Electrical Transient Analyzer Program

Underground Cable Raceway Systems

Ampacity Optimization Analysis - Uniform Ampacity

Method: Neher-McGrath

U/G System ID	Number of Cable Raceways	Number of Ext. Heat Sources
MS28-2 Secondary	1	0

Soil			Temperature Limits	
Type	RHO °C-cm/Watt	Ambient Temperature °C	Alarm °C	Warning °C
Average Dry	120.0	20.0	90.0	88.0

Multiplying Factors (MF)

Application MF: Not Considered

Individual Growth Factor: Not Considered

Global Growth Factor: 100 %

Output File: Y:\Lakefront\203110\ETAP\203110\MS28-2 Sec Cable.CD1S

Underground Cable Raceway Systems (RW1)

Duct Bank Raceway Data:

ID	Reference Distance Horizontal cm	Reference Distance Vertical cm	Dimension Height cm	Dimension Width cm	Fill Type	Fill RHO °C-cm/Watt	Number of Conduits	Number of Cables	Average Distance Center-to-Center cm
RW1	100.00	53.50	76.00	152.00	Light Aggregate	120.0	3	1	19.00

Conduit Data:

ID	Reference Distance Horizontal cm	Reference Distance Vertical cm	Type	Size mm	Thickness cm	OD cm	RHO °C-cm/Watt	Thermal R Ohm-m	Fill %
Cond1	57.05	38.00	PVC__40	91	0.574	10.160	600.0	0.374	39.50
Cond3	76.05	38.00	PVC__40	91	0.574	10.160	600.0	0.374	39.50
Cond2	95.05	38.00	PVC__40	91	0.574	10.160	600.0	0.374	39.50

* Warning - Industry representatives recommend avoiding a jam ratio of 2.8 to 3.2.

\# Alarm - Cable jamming may occur when jam ratio is in between 2.74 and 2.8.

Cable Data:

ID	Size	Rated kV	Current Amp	Individual Growth Factor %	Load Factor %	Conductor No.	Conductor Type	Conductor Per Phase	Conductor Construction	Insulation Type	Insulation Thickness mm	Insulation Thermal R Ohm-m
MS28-2 Sec Cable	1000	35.000	0.00	100	100	1/C	CU	1	ConRnd-NT	EPR	9.1	0.315

ID	Shielding Status	Shielding Type	Shielding Thickness mm	Sheath Type	Armor Type	End Connection*	Jacket Type	Jacket Thickness mm	Rdc @ 25°C μOhm/m	Outside Diameter cm
MS28-2 Sec Cable	Yes	Copper	0.1			Open	EPR	2.79	35.43	5.66

* End Connection is flagged as "Grounded" if any of the metallic layers (Shield/Sheath/Armor) is grounded at both ends.

Analysis Results (RW1)

No.	Cable ID	Conduit/Location ID	Conductor per Cable	Energized Conductor per Cable	Rdc @ Final Temp. µOhm/m	Dielectric Losses Watt/m	Yc	Ys	Conductor Losses Watt/m	Current Amp	Temp. °C
1	MS28-2 Sec Cable-1A	Cond1	1	1	43.79	0.640	0.064	0.001	25.951	746.49	86.19
2	MS28-2 Sec Cable-1B	Cond3	1	1	44.31	0.640	0.062	0.001	26.224	746.49	89.99
3	MS28-2 Sec Cable-1C	Cond2	1	1	43.79	0.640	0.064	0.001	25.951	746.49	86.19

Yc = Increment of AC/DC resistance ratio due to AC current skin and proximity effect

Ys = Increment of AC/DC resistance ratio due to losses of circulation and eddy current effect in shield , sheath and armor

Summary (RW1)

No.	Cable ID	Conduit/Location ID	Size	Current Amp	Temp. °C
1	MS28-2 Sec Cable-1A	Cond1	1000	746.49	86.19
2	MS28-2 Sec Cable-1B	Cond3	1000	746.49	89.99 #
3	MS28-2 Sec Cable-1C	Cond2	1000	746.49	86.19

F Indicates fixed cable size in cable sizing calculations or fixed cable ampacity in uniform ampacity calculation

* Indicates a cable temperature exceeding its limit

# Indicates a cable temperature exceeding its marginal limit

Lakefront Utilities Inc.

Specification 2022-01

EPC - 44/27.6 kV Substation

Lakefront Utilities Inc.

Rev 0

RAVEN ENGINEERING INC.

Lakefront Utilities Inc.

Revisions		
No.	**Date**	**Description**
A	2022-07-12	Issued for Review
B	2022-07-26	Incorporated owners comments
0	2022-07-29	Issued Final

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1. GENERAL

1.1 Scope

.1 Lakefront Utilities Inc. (LUI) intends to award an Engineer/Procure/Construct (EPC) contract for a new 20/26/33 MVA 44-27.6 kV Substation.

.2 This is a full EPC specification with the exception of the Material identified in Section 2.5 which will be provided by LUI.

.3 The substation is to be called Ontario Street MS28-3.

.4 The address of the station is 668 Ontario Street, Cobourg, Ontario.

1.2 Reference Codes and Standards

.1 This station is subject to the requirements of the Ontario Regulation 22/04. As such, the station must meet the technical requirements of the OESC or the NEC (based on IEEE standards).

.2 Ontario Building Code.

.3 ANSI/IEEE standards:

a)	IEEE Standard 80	Guide for Safety in Substation Grounding
b)	IEEE Standard 367	Recommended Practice to Determine GPR and Induced Voltage
c)	IEEE Standard 485	Recommended Practice for Sizing Lead-Acid Batteries for Stationary Applications
d)	IEEE Standard 605	Guide for Bus Design in Air Insulated Substations
e)	IEEE Standard 837	Standard for Qualifying Permanent Connections used in Substation Grounding
f)	IEEE Standard 980	Guide for Containment and Control of Oil Spills in Substations
g)	IEEE Standard 1189	Guide for Selection of VRLA Batteries for Stationary Applications
h)	ANSI/IEEE C37.90	Standard for Relays and Relay Systems
i)	ANSI/IEEE C37.91	Standard for Protecting Power Transformers

.4 CSA Standards:

a)	CAN/CSA C68.5	Shielded and Concentric Neutral Power Cable for Distribution Utilities.
b)	CAN/CSA A23.1	Concrete Materials and Methods of Concrete Construction
c)	CAN/CSA A23.2	Methods of Test and Standard Practice for Concrete
d)	CAN/CSA A23.3	Design of Concrete Construction

.5 Canadian Foundations Engineering Manual

1.3 Compliance with Codes and Standards

.1 It is the Bidders responsibility to be knowledgeable of the applicable Standards and Codes. Any changes or equipment alterations required for compliance with the Standards and Codes shall be at the Bidders expense.

1.4 Information Provided by Owner

The following documents are attached:

.1 Preliminary Single Line Diagram

.2 Preliminary Site Plan

.3 Short Circuit Study Report, April 12, 2022.

.4 Lakefront Utilities Grounding Report, 3548760-ELE-RPT-1. April 21, 2022.

.5 Geotechnical Investigation Proposed New Substation, 668 Ontario St., Cobourg. April 7, 2021.

1.5 Glossary

ANSI	American National Standards Institute
IEEE	Institute of Electrical and Electronic Engineers
LUI	Lakefront Utilities Inc.
NEC	National Electrical Code
OESC	Ontario Electrical Safety Code
USF	Utility Standards Forum

2. REQUIREMENTS

2.1 Engineering

.1 Provide complete engineering design including electrical, civil, structural, acoustic and mechanical for the new substation as per the attached preliminary Single Line Diagram.

.2 All drawings and engineering reports are to be sealed by a Professional Engineer, licensed in the Province of Ontario.

.3 The Contractor shall provide, as a minimum, the following detailed engineering drawings:

a) Single Line Diagram (including Protection & Control)

b) Site Plan including grading, drainage, access road and cross sections.

c) Grounding

d) Equipment Arrangement and Elevation Details

e) Foundations and Civil Structures

f) Structural Steel Plan, Elevations and Details

g) Cable Trench and Duct Bank Details

h) Control Building Structural and Architectural Details

i) Control Building Electrical Layout

j) Transformer Oil Containment System

k) Fence Layout and Details

l) 44kV Switch Pole Details

m) Protection & Control Schematics and Wiring Diagrams

n) AC and DC Station Service Distribution

o) Bill of Materials

p) Cable and Conduit Schedule

.4 Procure any municipal and provincial permits required for the project.

.5 Provide sediment and erosion control plan.

.6 Complete grounding design and confirm Step and Touch Potentials are in compliance with OESC Table 52 and IEEE Standards. Provide GPR Study and Grounding Report, signed by a P.Eng.

.7 Provide substation fence design in accordance with OESC requirements.

.8 Provide civil design for foundations including transformer foundation, oil containment, support structure foundations, pad-mount equipment foundations and concrete encased duct banks.

.9 Provide 44kV entrance design including new entrance pole, switches, fuses, circuit switcher and bus to transformer.

.10 Provide 27.6kV design including cables, pad-mount switchgear, pad-mount reclosers, station service transformer and underground feeder exits.

.11 Provide LV design including AC station service distribution, battery bank and charger, DC distribution, protective relaying and SCADA monitoring.

.12 Provide a Short Circuit, Coordination and Relay Setting Study, signed by a Professional Engineer.

.13 Provide programmable relay setting files.

.14 Confirm HV phasing matches existing system. There are two other 44/27.6kV substations in the Town of Cobourg with feeders that will be paralleled with the new station.

.15 Coordinate design review with Hydro One, including:

a) Provide project information and design drawings to Hydro One for design review,

b) Modify design as required to meet Hydro One connection requirements,

c) Prepare, complete and submit COVER document to Hydro One for connection authorization.

2.2 Procurement

.1 Regulation 22/04 requires that all equipment and materials used shall be approved by the Contractors Engineer for use in new construction.

.2 The Contractor shall provide a detailed bill of material, and demonstrate that the requirements of the Regulation have been met.

2.3 Circuit Switcher

.1 Contractor to specify and procure a circuit switcher for 44kV supply to the transformer.

.2 S&C Series 2000, Model 2010, 69kV, 1200A, 20kAIC, with horizontal interrupters and power operated disconnect.

.3 48Vdc control voltage.

.4 Complete with steel pedestal mounting, 120V heater.

2.4 Pad Mount Switchgear

.1 Contractor to select and procure a 5 way pad mount switch. See attached preliminary single line diagram for details.

.2 Reference Standards

IEEE C37.60 Standard for Overhead, Pad-Mounted, Dry Vault and Submersible Automatic Circuit Reclosers and Fault Interrupters for AC Systems up to 38kV.

IEEE C37.74 Standard Requirements for Subsurface, Vault and Pad-Mounted Load-Interrupter Switchgear and Fused Load-Interrupter Switchgear for AC Systems up to 38kV

IEEE C57.12.28	Standard for Pad-Mounted Equipment – Enclosure Integrity
IEEE 386	Standard for Separable Insulated Connector Systems for Power Distribution Systems Above 600V.
IEEE 1247	Standard for Interrupter Switches for AC, Rated Above 1000V.

.3 Switch technical requirements include:

a) 29kV nominal, 125kV BIL,

b) Sufficient continuous rating to permit full utilization of the transformer (FLA = 697 Amps),

c) 12.5kA interrupting rating,

d) Solid dielectric or SF6 insulation,

e) One (1) incoming way with disconnect switch, 900 Amp rated connections,

f) Four (4) outgoing ways with fault interrupters and phase and ground overcurrent protection,

g) 600 Amp dead break elbow connections,

h) Supply to station service transformer can use reducer bushing and 200A load break elbows,

i) PTs or voltage sensors on main bus,

j) SEL-751 protection relay on incoming way,

k) Tamperproof and lockable enclosure.

.4 Acceptable suppliers include S&C Electric, G&W Electric and ABB Elastimold.

.5 Switch to be equipped with sufficient visible open contacts and voltage test points to provide safe switching and isolation of all electrical equipment in accordance with the Utility Work Protection Code. The Contractor shall provide a written switching sequence and isolation plan to LUI for review and acceptance.

.6 Procurement of the selected pad mount switchgear requires approval by LUI.

.7 Switchgear to be installed on a suitable precast concrete base with manhole access for handling cables.

2.5 Pad Mount Reclosers

.1 Refer to the attached preliminary single line diagram.

.2 Reference Standards – See Section 2.3.2.

.3 Recloser technical requirements include:

a) 29kV nominal, 125kV BIL,

b) 600 Amp continuous rating,

c) 12.5kA interrupting rating,

d) Solid dielectric,

e) Internal CTs for protection,

f) Voltage monitoring on line and load sides,

g) SEL-651R recloser control c/w enclosure, battery backup, fused terminal blocks for AC supply,

h) Tamperproof and lockable enclosure.

.4 Acceptable suppliers include S&C Electric, G&W Electric and ABB Elastimold.

.5 Procurement of the selected pad mount reclosers requires approval by LUI.

.6 Reclosers to be installed on a suitable precast concrete base.

2.6 Material Provided by LUI

.1 One (1) main power transformer, 44/27.6kV, 20/26/33 MVA.

a) Transformer has been ordered and will be delivered to site.

.2 One (1) 50kVA Single phase pad-mount distribution transformer for station service.

2.7 Construction

.1 Perform clearing and grubbing, organic soil removal, excavation, bedrock scaling, backfilling and grading for site development as required. Supply all required materials for backfilling.

.2 Supply and install ground grid, including:

a) Grounding connectors shall be Burndy Hy-Ground compression type and shall meet IEEE-837,

b) Landscape fabric to limit vegetation growth,

c) 150mm clear crushed stone extending 1.5m beyond fence,

d) Perform fall of potential testing report to confirm adequacy of ground grid.

.3 Supply and install all concrete footings, precast concrete bases and pads.

.4 Engineer, construct and commission a transformer oil containment system in accordance with applicable regulations.

.5 Supply and install all steel structures.

.6 Supply and install all concrete-encased duct banks, including any necessary surface restoration.

a) Duct shall be DB2,

b) Clean all ducts before installing cable,

c) Spare ducts shall be provided with a pulling rope and capped.

.7 Supply and install 1.8m (6’) chain-link fence. Including:

a) Fence posts to be set in concrete with Sono-tube forms, concrete sloped to allow water runoff,

b) Three (3) strands of barb-wire at top,

c) One (1) 4.8 m wide vehicle gate,

d) Personnel access gate,

e) Tension wire provided at the bottom of the chain link mesh, grounded,

f) Fence grounding to be copper-weld conductor or Aluminum,

g) High voltage warning signs at intervals of at least 10m.

.8 Supply and install the 46 kV manually operated switch and pole.

a) Confirm phasing and install permanent phase markers,

b) Gradient control mat, bonded to the substation ground grid.

.9 Supply and install S&C Circuit Switcher and associated overhead bus.

a) Install permanent phase markers,

b) Switch status, trouble/failure alarms to be wired to SCADA RTU.

.10 Supply and install station class surge arresters.

.11 Receive and offload main power transformer, place on foundation and assemble as per manufacturer's instructions. Provide SFRA testing on arrival at site and after placement on foundation.

.12 Supply and install a pre-fabricated control building, including:

a) concrete slab foundation, sized to allow the building siding to extend beyond the foundation to prevent standing water on the foundation surface,

b) steel exterior siding, grey,

c) steel sloped roof extending 300mm beyond foundation,

d) R-25 insulation, vapour barrier and inside walls of 16mm (5/8") plywood, painted grey,

e) Grounding

i) Interior ground loop (#2/0 minimum) around all four walls,

ii) All metallic components of the building to be bonded,

iii) Bond ground loop to the station ground grid in at least (2) locations,

iv) use PVC sleeves through the concrete foundation as required,

f) Keyed access door lock, keyed to match existing LUI operation key,

g) Magnetic door contact wired to SCADA RTU for building entry alarm.

.13 Supply and install the following within the control building:

a) 200A AC distribution panel,

b) 200A station service auto-transfer switch, c/w auxiliary switch monitored by SCADA,

c) 200A entrance rated fused disconnect, meter base (outdoor) and buried 4" DB2 service duct for alternate station service supply,

d) exhaust fan with thermostat control, fresh air intake,

e) electric baseboard heat with thermostat control,

f) interior LED lighting,

g) interior receptacles,

h) exterior LED lighting

  i) (1) fixture above door,

  ii) (1) fixture facing yard.

i) Exterior GFCI receptacle,

j) 48Vdc battery bank, charger and DC distribution breakers,

k) protection & control rack(s) including transformer main and backup protection,

l) manual controls and indication for circuit switcher

m) SEL RTAC for SCADA monitoring c/w terminal strip and/or cabinet for termination of field cabling,

n) industrial grade, DC powered Ethernet switch,

o) communication to all Ethernet equipped relays and devices,

p) Ethernet communication to existing network switch located in MS28-1.

.14 Supply and install 120Vac distribution panel and cabling, including:

a) Separate ac supply breakers for:

  i) Battery charger,

  ii) Inside receptacles,

  iii) Outdoor receptacles (15A GFI),

  iv) Indoor lighting,

  v) Outdoor lighting,

  vi) baseboard heaters,

  vii) Transformer fans,

  viii) Pad mount switch power supply,

  ix) Pad mount recloser supply (3),

  x) Meter cabinet power supply,

.15 Supply and install station battery system, including:

a) Battery charger, 120/240Vac input, 48Vdc output,

b) 48V battery bank,

c) DC distribution breakers for

  i) relay power supplies,

  ii) circuit switch tripping,

  iii) circuit switcher closing,

  iv) SCADA RTU.

d) Charger trouble/failure alarms wired to SCADA RTU.

.16 Supply and install protection & control rack(s), including:

a) SEL-787 main transformer protection,

b) SEL-751 bus backup protection,

c) FT switches for all PT/CT inputs, digital inputs/outputs,

d) Terminal strips on side of rack for termination of field cables, panel wire from terminal strip to relays and devices,

e) Terminal strips to be mounted vertically with 45° brackets to provide suitable access to both sides of terminal blocks.

.17 Supply and install LV control wiring, including:

a) PT/CT cabling,

b) Trip/close control cabling,

c) Status and alarm cabling.

d) All field cabling to the control shall terminate on terminal strips with all conductors terminated in order. Panel wire to be used to connect field cabling to devices on P&C rack(s).

.18 Supply and install pad-mount switch, including power supply, control and communications cabling.

.19 Supply and install (3) pad-mount feeder reclosers, including power supply, control and communications cabling.

.20 Supply and install (3) feeder exit duct banks to LUI installed riser poles.

a) Feeder exit duct banks to be concrete encased.

b) Preliminary design lengths for tendering purposes:

i) F7 28 m

ii) F8 22 m

iii) F9 37 m

.21 Supply, install and terminate all 28kV underground cable, including feeder exits.

a) Feeder cables to be 1000mcm Al,28kV, 33% CN, XLPE.

b) Supply to 50kVA station service transformer to be #2/0 Al, 28kV, 100% CN, XLPE.

c) Cable terminations to pad-mount switch and reclosers to be IEEE-386 600A dead-break elbows c/w capacitive voltage test points.

d) Cable terminations to bolted connections to be cold-shrink. 3M QuickTerm-III or equivalent.

e) All lugs to be tin-plated copper compression type.

f) Feeder exit cables to be pulled to riser poles with sufficient cable length for LUI to terminate and connect.

.22 Install 50kVA single phase pad-mount station service transformer including primary and secondary conductors. Transformer to be supplied by LUI.

.23 Supply and install two (2) 4” DB2 conduits from Control Building to MS28-1 metalclad building:

a) One (1) for communications,

b) One (1) spare.

.24 Program all relays with approved settings.

2.8 <u>Work by Others</u>

.1 Provision of single phase underground service to the control building by LUI.

.2 Feeder exit riser poles c/w switches to be installed by LUI.

.3 Termination and final connection of feeder exit cables by LUI.

.4 New 44kV feeder tie switch between M2 (MS28-3) and M4 (MS28-1) by LUI.

.5 Master SCADA programming by others.

3. EXECUTION

3.1 Notice of Project

.1 The Contractor shall file a Notice of Project with the local office of the Ministry of Labour.

3.2 Permits

.1 The Contractor will obtain ESA Plan Review, Inspection and Authorization to Connect.

.2 The Contractor will obtain any required Municipal permits.

3.3 Engineering Drawings

.1 All drawings shall use the SI system of measurement. Imperial measurements shall be included in brackets for reference where practical.

.2 Drawings shall be on D size sheets.

.3 All drawings shall be to scale, legible, and in English. Minimum text height 2.5mm.

.4 Issued for Construction drawings shall be checked, stamped and sealed by a Professional Engineer.

.5 Issued for Construction drawings shall have a Certificate of Approval signed by a Professional Engineer, as per Regulation 22/04.

.6 After construction is complete the Contractor shall submit final drawings in both paper and electronic format including both PDF and DWG drawing files. The drawings shall be labelled “As Built” and shall include all changes and modifications made during construction, and commissioning.

3.4 Design Review

.1 The Contractor shall facilitate as a minimum bi-weekly online meetings to communicate project status and project safety. The frequency of the meeting may increase during periods of peak construction or at the Owner’s request.

.2 The Contractor shall submit design review packages to LUI:

a) 30% design including site plan, SLD and major electrical equipment selection,

b) 60% design including electrical arrangements, civil and structural design, oil containment,

c) 90% design including details, interconnections, low voltage, protection & control, SCADA,

d) 100% design – Issued for Construction.

.3 LUI will review the design and provided comments back to the Contractor.

.4 The Contractor will hold an online meeting at each stage of design review to discuss the comments and agree upon direction.

.5 Review and acceptance of design drawings by the Utility shall not relieve the Contractor of responsibility for correctness thereof, or for meeting all of the requirements of the Contract, nor from faults arising from errors, omissions or defects, nor for failure in the matter of warranty, which may become evident during installation or subsequent operation.

3.5 Shop Drawing Approval

.1 The Contractors Engineer shall receive, review and approve vendor shop drawings on behalf of LUI.

.2 Copies of approved shop drawings shall be provided to LUI on request.

3.6 Underground Locates

.1 The Contractor shall obtain locates for all underground plant as required.

3.7 Construction Service

.1 The Contractor shall provide and install a meter base and associated equipment for temporary electrical service.

.2 The utility will provide service layout prior to installation.

.3 The temporary service will require ESA inspection prior to energization.

.4 Electricity usage shall be bill to the contractor.

.5 LUI will supply and install an overhead transformer (if required) and service conductor to the meter base.

3.8 Site Maintenance

.1 The substation site includes an existing substation and water tower, and is used for the storage of transformers, poles and other utility inventory. The Contractor shall use temporary fencing to demarcate and control access to the new substation site.

.2 The Contractor shall keep the site clean and tidy at all times, free from accumulation of waste products and debris.

.3 At the end of each day, the site shall be cleaned and any waste to be placed in waste bins provided by the Contractor.

3.9 Safety

.1 The Contractor will provide and follow a project specific Safety Plan.

.2 The Contractor shall immediately report any safety related incidents or Ministry of Labour orders and visits.

3.10 Commissioning

.1 The Contractor shall provide a detailed Commissioning Plan identifying all tests and verifications required to confirm the installation.

.2 Commissioning Plan to include as a minimum:

a) Recording of nameplate data, ratings, serial #’s etc. for all major equipment,

b) Visual inspection, confirmation of connections including grounding,

c) Confirmation of nomenclature labelling,

d) HV Switch

i) Insulation resistance,

ii) contact resistance.

e) Circuit Switcher

i) Insulation resistance,

ii) Contact resistance,

iii) Opening and closing time measurement.

f) Power Transformer

i) Phasing,

ii) Ratio Test,

iii) Insulation resistance,

iv) Winding resistance,

v) Capacitance test,

vi) Oil analysis including DGA,

vii) Confirm auxiliary devices, gauges, alarms and trips,

viii) Any commissioning tests recommended by the manufacturer,

ix) Sweep Frequency Response testing before unloading and after placement on foundation,

x) CT ratio, polarity and saturation tests.

g) HV Cables

i) VLF testing.

h) LV Cables

i) Continuity testing.

i) Protection Relays

i) Secondary injection testing,

ii) Test trip to all interrupting devices,

iii) Record phasors when loaded and confirm phasing and magnitude.

j) SCADA

i) Confirm communications,

ii) End to end point testing.

k) DC Battery System

i) Confirm correct operation of charger,

ii) Confirm Float and equalize voltages.

.3 The Contractor shall submit copies of all test reports, signed and dated, confirming that the test results are in compliance with the applicable specifications and standards.

END

VECC-3

Ref: Manager's Summary p. 49

Please provide Table 7 on the basis of actuals for 2022 and 2023 and current budgeted amounts for 2024 to 2026.

LUI Response:

Capital Expenditures by Category
000's

	Actual		Projection	Budget	Forecast
Description	**2022**	**2023**	**2024**	**2025**	**2026**
System Access	1,292	3,046	650	990	990
System Renewal	1,889	1,433	724	1,045	1,440
System Service	155	159	125	80	100
General Plant	95	601	140	778	297
Total Expenditures	**3,430**	**5,238**	**1,639**	**2,893**	**2,827**
Capital Contributions	(378)	(765)	(400)	(760)	(760)
Total Net Capital Expenditures	**3,052**	**5,238**	**1,639**	**2,893**	**2,827**

VECC-4

Ref: Manager's Summary p. 49

In the same format as Appendix 2-AA, please provide project details for the years 2022 to 2025.

LUI Response:

LUI respectfully requests an extension to this question, with a response to be submitted by January 17, 2025 through RESS and by email to all required parties.

VECC-5

Ref: Manager's Summary p. 49

The evidence states "The business case for this project is filed as Appendix A." Appendix A contains the Current Tariff sheets.

Please provide the referenced Appendix A for the ICM project.

LUI Response:

See page 52 – 60 of the IRM Application.

VECC-6

Ref: Manager's Summary p. 50

a) Please provide a detailed breakdown of actual costs for the 27.6 kVA Victoria Street Substation for each of the years 2022 and 2023.

LUI Response:

Cost Type	2022	2023	Total
Labour	8,737	45,487	54,224
Materials	-	47,636	47,636
Equipment	-	5,220	5,220
Subcontractors	360,687	2,067,543	2,428,230
	369,424	**2,165,886**	**2,535,311**

b) Please provide the start date of the project.

LUI Response:

The contract with the vendor KPC was dated October 13, 2022.

c) Please compare the costs in part (a) to the approved budget for the project.

LUI Response:

See response for interrogatory CCMBC-8b).

d) Please compare the costs in part (a) to LUI's recent projects of similar scope.

LUI Response:

Lakefront does not have any recent projects of comparable scope for purposes of comparison. While there is a financial system requirement with a cost approximately one-fifth of this project, we will be prudently evaluating costs and adhering to the same approach with an RFP. This process will be conducted in preparation for our upcoming Cost of Service filing for the 2027 rates.

e) Please discuss, based on the approved project budget and the cost of recent projects of similar scope, why LUI believes the final costs for the 27.6 kVA Victoria Street Substation were prudently incurred.

LUI Response:

Lakefront produced the Engineering, Procurement, and Construction (EPC) specifications for the new substation, tendered the specification to several qualified contractors, evaluated the bids received from the qualified contractors and selected the lowest bid for award of contract. Lakefront, along with its external engineer (Raven Engineering), prudently managed any extra / additional costs from the contractor through the construction period. Lakefront purchased the substation transformer directly for the new substation and again followed a prudent approach of producing a specification for the transformer, tendered to several qualified vendors, evaluated the tenders received and awarded to the lowest cost vendor that met the specification.

VECC-7

Ref: Manager's Summary p. 51

LUI’s 2023 regulatory ROE was calculated to be 4.27%, 4.39 basis points below a deemed ROE for LUI of 8.66%.

Please provide the ROE for 2024 and the forecast for 2025.

LUI Response:

See file attached “LUI_2023_to_2025_ROE.xls”

VECC-8

Ref: Manager’s Summary p. 51

Prior to the construction of the MS28-3 Substation, Lakefront identified a need for additional capacity in Cobourg to meet existing and future demand growth in the East area of Cobourg; at the time primarily supplied by the existing Brook Road substation. Lakefront determined that a new substation was required to accommodate demand growth and reduce load at its two (2) existing 27.6 kV substations (MS28-1 and MS28-2). The construction for a new substation (MS28-3) was completed and energized in December of 2023.

a) Please provide a list of LUI’s existing substations in Cobourg at the end of 2021 (prior to the need for MS28-3) and include the feeder #, voltage, number of customers, capacity, and available feeder capacity by feeder.

LUI Response:

See the Station Capacity Study in VECC-2 prepared by Raven Engineering with the final issue dated December 15, 2020, for information related to LUI’s feeders. There were no changes to the feeder related information in the study to the end of 2021. See “Customer Count Per Feeder” table below.

Customer Count Per Feeder - 2022

Feeder Number	Number of Customers
Victoria F1	3133
Victoria F2	1810
Victoria Colb F1	185
Victoria Colb F2	340
Victoria Colb F3	370
Durham Colb F4	195
Durham Colb F5	360
Brook F4	1455
Brook F6	1265
D’Arcy F9	210
Orr F13	340
Orr F14	455
Kerr F19	527

b) Please provide the same information as part (a) at the end of 2023, after the construction of MS28-3.

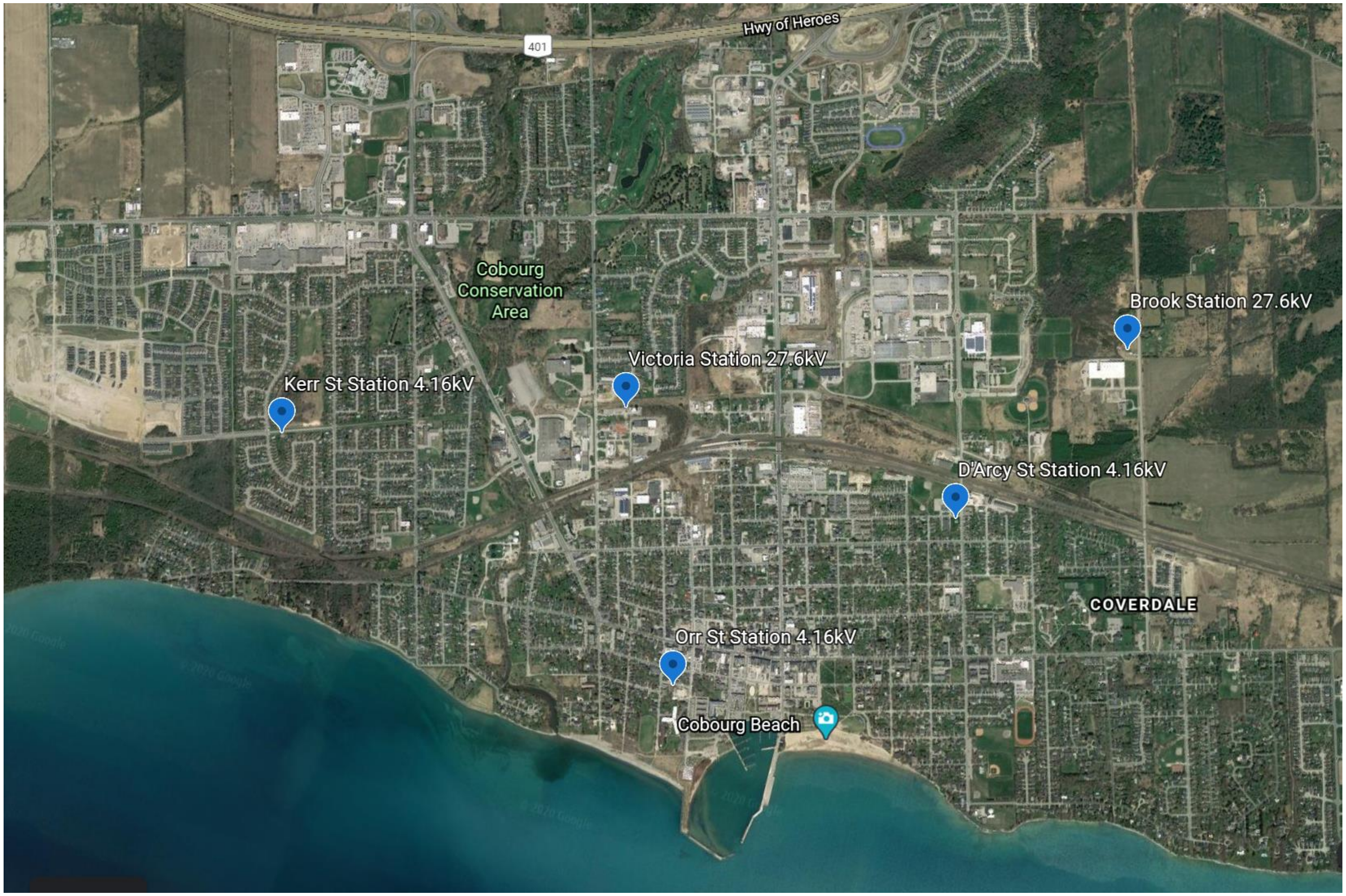
LUI Response:

Following the completion of MS28-3, there are 3 new 27.6 kV feeders available for utilization, each having approximately 10 MVA of capacity. Approximately one half the customers on the existing F1 and F2 feeders were transferred to 2 new feeders from MS28-3. One of the new feeders from MS28-3 is for future use.

c) Please provide a map which shows the location of each substation in Cobourg.

LUI Response:

See the attached “Cobourg Substations Map” below. MS28-3 is located immediately next to the “Victoria Substation” indicated on the map.


Hwy of Heroes
401
Cobourg
Conservation
Area
Brook Station 27.6kV
Victoria Station 27.6kV
Kerr St Station 4.16kV
D'Arcy St Station 4.16kV
COVERDALE
Orr St Station 4.16kV
Cobourg Beach

VECC-9

Ref: Manager's Summary p. 54

With respect to Project Justification, LUI refers to Growing Capacity Requirements and the residential and commercial developments in LUI's service area that have significantly increased the demand for electricity. The new substation adds necessary capacity to manage this growth efficiently.

a) Please provide a summary of LUI's latest residential and commercial development forecasts including the associated load by year by substation.

LUI Response:

LUI does not forecast load growth by category (residential/commercial/etc.) but does forecast overall load growth for its service territory. Please see the attached latest load forecast prepared for the Peterborough to Kingston Regional study during the summer of 2024 with filename "Load_Forecast_Lakefront_Utilities_2024.xls".

b) Please demonstrate how the new substation adds necessary capacity to manage this forecasted growth compared to the status quo.

LUI Response:

There were three main drivers for the construction of the new substation: 1) Load growth, 2) 4.16 kV to 27.6 kV conversion, 3) Reliability/Redundancy. Per the Station Capacity Study in response to VECC-2 prepared by Raven Engineering, the new substation was necessary to facilitate the expected load growth in Cobourg, completion of the 27.6 kV conversion program and to provide additional reliability/redundancy for the 27.6 kV distribution system.

VECC-10

Ref: Manager's Summary p. 54

With respect to Project Justification, LUI indicates the substation improves the overall reliability of the electrical system by reducing the load on existing substations and providing backup options in case of equipment failure or maintenance.

a) Please provide the reduced load on each existing substation.

LUI Response:

The load on the existing MS28-1 has been reduced by approximately 50%. The 27.6 kV distribution system was reconfigured in order to utilize two new feeders from the new substation resulting in the load reduction. There has been no load reduction on MS28-2 as a result of the new substation.

b) Please provide the number of outages and customer minutes of interruption for the MS28-1 and MS28-2 substations for each of the years 2020-2024.

LUI Response:

	MS28-1		MS28-2	
	# Outages	Cust. Hours of Interruption	# Outages	Cust. Hours of Interruption
2020	12	22,687	11	27,189
2021	14	7,683	7	191
2022	14	2,257	11	3,719
2023	32	23,118	16	4,879
2024*	27	11,577	15	19,070

* 11 Months

VECC-11

Ref: Manager’s Summary p. 54

With respect to Project Justification, LUI indicates the substation introduces redundancy, which is crucial for maintaining continuous power supply during unforeseen outages or planned maintenance activities.

Please explain further how the substation provides additional redundancy on the system compared to the status quo.

LUI Response:

The new substation provides a third 44 – 27.6 kV substation transformer versus the two in the status quo scenario. In the status quo scenario, if one substation transformer is forced out of service, all of the 27.6 kV customers are supplied on just one transformer. The new substation provides additional redundancy by providing two transformers to supply 27.6 kV customers in the event one transformer is forced out of service.

VECC-12

Ref: Manager’s Summary p. 54

With respect to Project Justification, LUI indicates the substation provides the necessary capacity for completing the 4.16 kV to 27.6 kV voltage conversion program in Cobourg.

Please explain further how the substation contributes to the completion of the 4.16 kV to 27.6 kV voltage conversion program in Cobourg compared to the status quo.

LUI Response:

In the status quo scenario during peak loading periods, one of the two 44-27.6 kV substation transformers was at 50% of its maximum nameplate capacity limit. In a scenario where one of the substation transformers was forced out of service, the other transformer would be at 100% of its maximum nameplate capacity, indicating that no new load could be added to the 27.6 kV distribution system. Currently there is approximately 5 MW of peak load on the 4.16 kV distribution system in Cobourg. Completing the 4.16 kV conversion and adding the 5 MW of peak load to the 27.6 kV system would create a situation where the one transformer in the above-described scenario would exceed its maximum nameplate capacity. See response to VECC-2 for the Substation Capacity Study prepared by Raven Engineering.

VECC-13

Ref: Manager’s Summary p. 54

The evidence states “Lakefront deliberated on invoking cost-sharing with residential developers, as directed in the Distribution System Code (DSC), to mitigate the financial impact on our existing customers. However, we are persuaded that recent events, including the Ontario government's intervention in overturning an OEB directive regarding Enbridge’s economic evaluation for rural expansion, may override this requirement. Hence, in this application, we are proposing full recovery of the substation costs from our entire customer base. We seek OEB guidance and direction on this matter to ensure compliance and equitable cost distribution.”

a) Please provide the capital contributions and impact on the ICM request if LUI had invoked cost-sharing with the residential developers as per the DSC.

LUI Response:

To address the challenges of cost recovery, it is essential to consider the broader implications of the station's purpose and capacity. Understanding its system-wide role highlights why a narrowly focused recovery model is inadequate.

The new station has a capacity of 33 MVA, with planned loading capped at 26.6 MVA. This conservative approach ensures sufficient headroom to handle unexpected load growth, maintain redundancy, and allow for operational flexibility, thereby preventing overloading scenarios that could compromise system reliability.

Our 4.16 kV to 27.6 kV voltage conversion constitutes 15% of the station's capacity (5 MVA). This upgrade enhances the system's ability to manage higher capacity loads efficiently, reduces energy losses over long distances, and aligns with modern standards to support future growth and operational adaptability.

This leaves approximately 85% of the new station's capacity to supports load growth and redundancy, critical for accommodating regional expansion.

The difficulty we face is in creating a a realistic forecast of how the new station can be reasonably allocated to any distinct expansion plan.

For instance, our current projections estimate that 1,466 new homes will connect to the grid over the next five years. Simplistically allocating station costs based solely on these projections leads to the following distribution:

Subdivision Name	Number of Lots	Projected Load (kVA)	Proportional Split	Potential Contribution ($)	Cost per Unit
Tribute Phase 2	105	315	7.2%	179,058.66	1,705.32
Victoria Meadows	72	216	4.9%	122,783.08	1,705.32
New Amherst Phase 3	135	405	9.2%	230,218.28	1,705.32
Tribute Phase 3	163	489	11.1%	277,967.26	1,705.32
Tribute Phase 4	176	528	12.0%	300,136.43	1,705.32
Tribute Phase 5	233	699	15.9%	397,339.70	1,705.32
Tribute Phase 6	182	546	12.4%	310,368.35	1,705.32
Sunnyside Village	100	300	6.8%	170,532.06	1,705.32
Mistral - Brook Road North	300	900	20.5%	511,596.18	1,705.32
Total	**1,466**	**4,398**	**100%**	**2,500,000.00**	

While this recovery model appears straightforward, it presents significant challenges. For instance, allocating $1,705 per home disregards the station's broader benefits, such as redundancy and system support for existing infrastructure. This approach unfairly burdens a narrow customer group, creating inequities and failing to reflect the shared advantages to all ratepayers.

Also, there is some natural growth in commercial services that come with new homes and also opportunity for new industry if a sufficient labour pool is available. Unfortunately, these cannot be reasonably forecasted. Using a static model such as that above creates issues when applying new contributions which should be collected from unforecasted load and refunding those contributions to the rightful party.

Below are key considerations:

1. Station Design and Purpose

The station was built to address system-wide growth, redundancy, and reliability across the service area. Its capacity supports the entire network, not just discrete projects or customer segments. Thus, attributing costs solely to new customers overlooks its critical role in supporting existing infrastructure and ensuring reliability for all users.

- **Growth and Redundancy Allocation:** The station's design prioritizes system-wide capacity and resilience. Attempting to allocate costs exclusively to new developments would fail to acknowledge the shared benefits of redundancy and reliability for all users.

2. Challenges with Micro-Level Cost Allocation

Electricity distribution systems are inherently complex, making granular cost allocation impractical. Factors such as load diversity, usage patterns, and shared infrastructure introduce significant difficulties in establishing an accurate and fair recovery model.

- **Lack of Granular Data:** The system does not track detailed usage contributions by individual customer groups, making it impossible to justify specific allocations.

- **Interdependencies in Load Growth:** Residential developments indirectly support industrial and commercial growth. Recovering costs solely from new residential customers ignores the broader economic benefits shared across all rate classes.

3. Risk of Overburdening New Customers

Charging $1,705 per home as a recovery mechanism disproportionately impacts new residential developments, with potential negative consequences:

- **Distorted Development Economics:** High upfront costs may deter developers, reduce affordability for homebuyers, and slow regional growth.
- **Neglect of Shared Benefits:** Redundancy and reliability improvements benefit all ratepayers. Charging only new customers ignores these collective advantages, violating principles of fairness.

Conclusion

The station's purpose and design make it unsuitable for a recovery model targeting specific customer groups, such as new residential developments. Its shared benefits and the practical limitations of micro-level cost allocation necessitate a broader, more equitable approach. Utilizing mechanisms like the ICM ensures fair cost distribution, preserves ratepayer fairness, and supports sustainable system growth.

b) Please explain further how the Ontario government's intervention in overturning an OEB directive regarding Enbridge's economic evaluation for rural expansion, may override this requirement.

LUI Response:

Lakefront's reference to the Ontario government's intervention in overturning an Ontario Energy Board (OEB) directive concerning Enbridge's economic evaluation for rural expansion highlights a significant precedent in regulatory decision-making. In December 2023, the OEB mandated that Enbridge Gas require developers to pay the full costs of new natural gas connections upfront, aiming to mitigate the risk of stranded assets amid the energy transition. This decision was based on concerns that amortizing these costs over 40 years, as previously practiced, could leave future ratepayers responsible for underutilized infrastructure.

However, the Ontario government swiftly intervened, expressing concerns that the OEB's decision would increase housing costs and impede development. Energy Minister Todd Smith announced plans to introduce legislation to reverse the OEB's ruling, emphasizing the government's commitment to keeping energy costs down and supporting housing construction.

This governmental action effectively attempts to override the OEB's directive, reinstating the practice of spreading connection costs over an extended period, thereby reducing immediate financial burdens on developers and promoting development. Lakefront interprets this intervention as indicative of the government's willingness to modify or overturn regulatory decisions to align with broader policy objectives, such as housing affordability and economic growth.

Consequently, Lakefront is concerned that adhering strictly to the Distribution System Code's cost-sharing requirements with developers might be superseded by similar governmental interventions. By proposing to recover the substation costs from the entire customer base on a hybrid basis, Lakefront seeks to align with current governmental priorities and avoid potential conflicts between regulatory compliance and overarching policy directives. This approach aims to ensure both compliance and equitable cost distribution in a dynamic regulatory environment.

VECC-14

Ref: Manager's Summary p. 60

Please provide the bill impacts for the typical customer, resulting from the ICM approvals sought in this proceeding.

LUI Response:

This has been provided in the IRM Rate Generator Model.

OEB Staff Interrogatories

Staff-1
Ref. 1: Lakefront Utilities Inc. Scorecard

Preamble:
The following table was created from the information in the Lakefront Utilities' 2023 Scorecard.

Table 1: Return on Equity (ROE)

	2019	2020	2021	2022	2023
Deemed	8.78%	8.78%	8.78%	8.66%	8.66%
Achieved	7.58%	5.49%	5.93%	10.87%	4.27%
Diff	-1.20%	-3.29%	-2.85%	2.21%	-4.39%

Question(s):

a) What drivers were responsible for the increased ROE in 2022?

LUI Response:

The drivers responsible for the increased ROE in 2022 are due to staffing vacancies from attrition.

b) What drivers contributed to the decreased ROE in 2023?

LUI Response:

The drivers contributing to the decreased ROE in 2023 are due to infrastructure investments and consulting costs covering staffing vacancies.

Staff-2
Ref. 1: 2025 IRM Application, p. 54

Preamble:
Lakefront Utilities states “The construction of new substation (MS28-3) was completed and energized in December of 2023”.

Question(s):
Please list the amounts, by asset class (i.e. OEB USoA) that were

a) Capitalized for MS28-3 in 2022.

   LUI Response:

   This is non-applicable as the substation was not capitalized in 2022.

b) Capitalized for MS28-3 in 2023.
   LUI Response:

   This is responded with **Staff-2 d)**

c) Depreciated for MS28-3 in 2022.

   LUI Response:

   This is non-applicable as the substation was not capitalized in 2022.

d) Depreciated for MS28-3 in 2023.

LUI Response to Staff-2 b) and d):

APH		Total Cost	Depreciation rate (Years)	Annual Depreciation 2023	2024	NBV
1820 - Distribution Station		2,239,342.25	45	24,881.58	49,763.16	2,164,697.51
1830 - Poles and Fixtures		17,860.42	45	198.45	396.90	17,265.07
1835 - OH Conductors and Devices		59,905.08	55	544.59	1,089.18	58,271.31
1840 - UG Conduit		169,452.27	50	1,694.52	3,389.05	164,368.70
1845 - UG Conductors and Devices		41,022.27	35	586.03	1,172.06	39,264.17
1850 - Line Transformers		7,229.51	35	103.28	206.56	6,919.67
1855 - OH Services		499.05	55	4.54	9.07	485.44
	Total	2,535,310.85		28,012.99	56,025.98	2,451,271.87

Staff-3
Ref. 1: EB-2021-0039, Exhibit 2, Appendix B, p. 50
Ref. 2: 2025 IRM Application, p. 52

Preamble:
The project-related business case in Ref. 2 describes the project as “27.6 kV substation MS28-3 on Ontario Street, Cobourg Project System Access”.

The following image is a table from the Lakefront Utilities 2022-2026 Distribution System Plan.

Table 9: Municipal Substation Listing

Cramahe			
Station	Voltage	Capacity (MVA)	Feeders
MS 1 - Victoria	4.16 kV	5	F1, F2, F3
MS 2 - Durham	4.16 kV	5	F4, F5
Cobourg			
Station	Voltage	Capacity (MVA)	Feeders
MS 2 – D’Arcy	4.16 kV	5	F10
MS 3 – Orr	4.16 kV	5	F13, F14, F15
MS 5 – Kerr	4.16 kV	5	F19, F20
MS 28-1 - Victoria	27.6 kV	20	F1, F2
MS 28-2 - Brook	27.6 kV	20/26/32	F4, F6

Question(s):

a) Please confirm that the information in Table 9 is correct or revise as required.

LUI Response:
LUI is confirming Table 9 is correct.

b) Please confirm that the Victoria Street Substation, the subject of this application, MS 28-3, is an additional substation in Cobourg.

LUI Response:
LUI is confirming MS28-3 is an additional substation.

i. When did Lakefront Utilities purchase the land for the substation?

LUI Response:

The land for MS28-3 was previously owned by Lakefront Utilities. The land was purchased from the former Hydro One in the 1950's and is also used for MS28-1 and a material storage yard.

c) Please describe the tendering processes used for material acquisition and construction services that Lakefront Utilities undertook for this project.

Lakefront Utilities produced a Substation Specification document and placed the document out for an EPC tender (see VECC-1 c for documentation). A number of tender responses were received and evaluated (see "Summary of Bids" document below) and the project was awarded to the lowest cost bidder.

RAVEN ENGINEERING INC.

6251 O'Neil St., Unit 2
Niagara Falls, ON
L2J 1M6
905-357-4413

Summary of Bids

New Substation MS28-3 (Ontario Station)

Lakefront Utilities

Rev 0

1.0 Background

Lakefront Utilities Inc. (LUI) intends to award an Engineer/Procure/Construct (EPC) contract for a new 20/26/33 MVA 44-27.6 kV Substation.

This is a full EPC specification with the exception of the main power transformer, 44/27.6kV, 20/26/33 MVA and 50kVA Single phase pad-mount distribution transformer for station service which will be provided by LUI.

Competitive prices were obtained and summarized below for the supply, fabrication, installation and connection of the annunciator panel and associated cables.

2.0 Recommendation

We recommend that Lakefront Utilities proceed with the procurement of services from **KPC Power Electrical Ltd.** for the engineering, procurement and construction of New Substation MS28-3 (Ontario Station), for the price of **$1,368,000**.

3.0 Quotes

A Request for Pricing (RFP) was issued to seven pre selected vendors.

The following pricing was received:

• KPC.	$1,368,000.00	190 days
• Black & McDonald limited.	$1,615,000.00	262 days
• K-LINE.	$1,985,201.56	256 days
• Kroon.	No Bid	
• Westmore Pole Line and Electric	No Bid	
• Dundas Power.	No Bid	
• Synergy Power	No Bid	

4.0 Analysis

The bids were reviewed and compared to the Request for Pricing and Scope of Work documents.

KPC had the lowest bid price, shortest schedule, and has a long history of working with Lakefront Utilities.

KPC submitted an alternative price for the use of SorbWeb fabric for oil containment with a cost savings of $15,525. The preferred design is a concrete containment pit which has lower remediation costs in the event of an oil spill. We don't feel the costs savings provided are significant enough to offset these costs.

Dundas Power and Synergy Power dropped out of the bidding process while Kroon and Westmore Pole Line and Electric did not submit a bid.

Prepared by Shola Akinrinade, EIT

Reviewed by Andrew Durward, P. Eng.

d) What was the time between purchase and delivery of the substation transformer?

LUI Response:

The substation transformer was ordered during July 2022 and delivered during August 2023 (13 months).

e) What party(s) performed the substation construction and commissioning?

LUI Response:

KPC High Voltage Utility Solutions Group.

f) Please provide the initial estimate and business case for the project.

LUI Response:

- For the initial estimate see CCMBC-8a response.
- For the business case see VECC-5 response.

g) Please describe the cost controls that were put in place throughout the project to contain the project costs.

LUI Response:

MS28-3 was constructed under a fixed-price Engineering, Procurement, and Construction (EPC) contract. Extra charges were reviewed and vetted by LUI and Raven Engineering and approved / disapproved on a case-by-case basis. The substation transformer was purchased directly by Lakefront Utilities through a specification/tendering process.

h) Please fill out the following table.

Table 2: MS 28-3

Item	
Power Transformer Nameplate Data:	**LUI Response:**
Manufacturer	PTI Transformers
Year of Manufacture	2023
kVA rating (nominal and extended)	20/26.7/33.3 MVA
Are transformer fans installed	Yes
Primary and secondary voltages	44,000 – 27,600 Y / 15,935 V
Low Voltage Amperes	697
Station kVA rating	20/26.7/33.3 MVA
Number of secondary feeders	3
Amperage Rating of secondary feeders	384 A (80% of 480 A pickup)

Staff-4
Ref. 1: 2025 IRM Application, p. 47

Preamble:
Lakefront Utilities states "the sudden need for the project in 2023 was driven by unforeseen residential developments, notably influenced by the Provincial Government's incentives to encourage faster home construction".

Question(s):
OEB staff are looking for specific details of the load growth in Cobourg which lead to the need for the substation construction.

a) For MS28-1, MS28-2, MS28-3, MS 2, MS 3, and MS 5, please provide:
   i. Planning limit for each of the stations

LUI Response:

See below figure showing 27.6 – 4.16 kV Stations Loads 2018 – 2024. Note: Historical loading information is only available from 2018 for 27.6 kV stations and 2019 for 4.16 kV stations.

Lakefront 27.6 / 4.16 kV Station Loads (2018/2019-2024)

27.6 kV

2018 Peak (MW)		2019 Peak (MW)		2020 Peak (MW)		2021 Peak (MW)		2022 Peak (MW)		2023 Peak (MW)		2024 Peak (MW)			Planning Limit (MW)		
MS28-1	MS28-2	MS28-1	MS28-2	MS28-1	MS28-2	MS28-1	MS28-2	MS28-1	MS28-2	MS28-1	MS28-2	MS28-1	MS28-2	MS28-3*	MS28-1	MS28-2	MS28-3
16.10	12.00	13.70	12.80	17.40	28.10	19.80	17.70	18.30	23.20	23.00	22.10	19.70	19.60	20.52	21.28	18.64	26.64

* Peak was on December 5th;
Only feeders F7 and F9 were online.

4.16 kV

2019 Peak (MW)	2020 Peak (MW)	2021 Peak (MW)	2022 Peak (MW)	2023 Peak (MW)	2024 Peak (MW)	Planning Limit (MW)
D'Arcy	D'Arcy	D'Arcy	D'Arcy	D'Arcy	D'Arcy	
0.80	1.50	1.80	2.40	1.70	0.90	3.46

2019 Peak (MW)	2020 Peak (MW)	2021 Peak (MW)	2022 Peak (MW)	2023 Peak (MW)	2024 Peak (MW)	Planning Limit (MW)
Kerr	Kerr	Kerr	Kerr	Kerr	Kerr	
1.75	2.03	2.99	3.29	2.12	2.01	3.46

2019 Peak (MW)	2020 Peak (MW)	2021 Peak (MW)	2022 Peak (MW)	2023 Peak (MW)	2024 Peak (MW)	Planning Limit (MW)
Orr	Orr	Orr	Orr	Orr	Orr	
3.20	3.48	3.50	3.20	3.37	3.73	3.46

ii. Station peak load from 2013-2023

LUI Response:

See response in Staff-4 a) i)

iii. Projected peak load that Lakefront Utilities had for 2023-2028, at the time when it decided to undertake this project.

LUI Response:

See VECC-2 response for Station Capacity Study prepared by Raven Engineering.

b) Please provide the following information on new connections in Cobourg for each year from 2020 through 2023, and 2024 to date.

i. Number of new connections by customer class

LUI Response:

See CCMBC-3 Figure 1 for response.

ii. For residential connections, the average load assumptions per unit

LUI Response:
Lakefront utilizes an average diversified load of 3 KVA per residential connection.

iii. List of the additional peak loads for new general service connections.

LUI Response:

Street #	Street Name	Peak Load (kVA)	Substation	Feeder
1125	ELGIN WEST	880	MS28-1	F1
555	COURTHOUSE ROAD	650 (Est)	MS28-1	F1
1025	ELGIN WEST	120	MS28-1	F1
702	ONTARIO STREET	7	MS28-1	F1
941	CHARLES WILSON PKWY	16	MS28-1	F1
1154	DIVISION STREET	34	MS28-2	F4
8950	DANFORTH ROAD	5	MS28-2	F4
990	DIVISION STREET	75	MS28-2	F4
1043	DIVISION STREET	25	MS28-2	F4
160	DENSMORE ROAD	1	MS28-2	F4
163	ELGIN EAST	8	MS28-2	F4
299	ELGIN EAST	120	MS28-2	F4
155	DODGE STREET	245	MS28-2	F6
432	KING EAST	65	MS28-2	F6
428	KING EAST	14	MS28-2	F6
135	ORR STREET	194	MS28-3	F9
82	MUNROE STREET	54	MS28-3	F9
114	DIVISION STREET	35	MS28-3	F9

iv. For each of the items above, indicate what station they would be connected to.

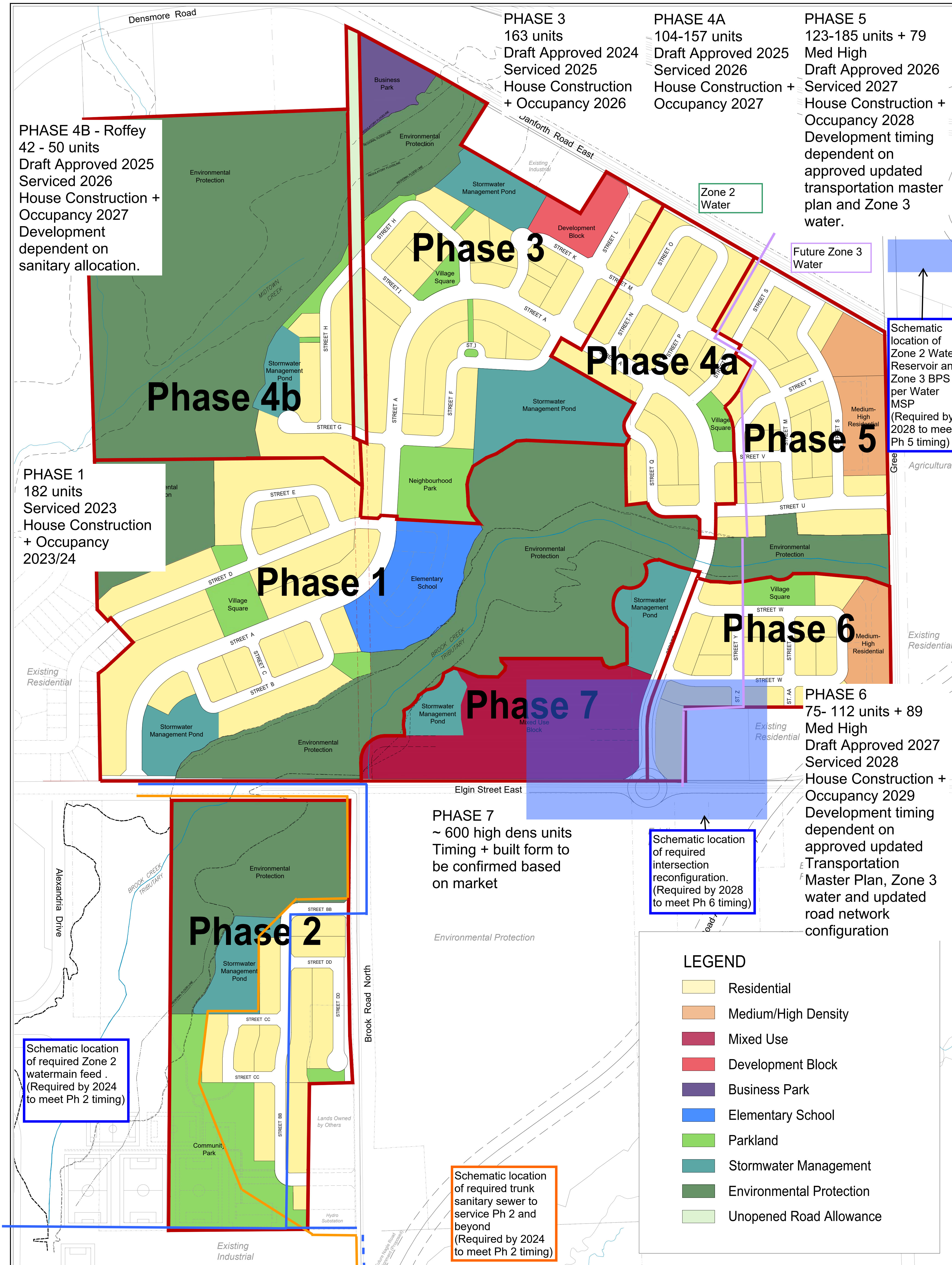
LUI Response:

See Staff-4 b) iii) response.

c) Please provide evidence of increased residential and commercial development planning activity in Lakefront Utilities' Cobourg service area in 2020-2022.

LUI Response:

The north-east area of Cobourg (Brook Road from King Street to Elgin Street East and Elgin Street East north and east of Brook Road) is mostly vacant land. Currently there are two large developers (Tribute and Mistral) that have purchased land in this area and are currently developing the land for residential use. See Tribute Phasing Plan” below for reference.



COBOURG TRAILS

Composite Land Use Plan

Feb. 2024

Staff-5
Ref. 1.: **Electricity Reporting & Record Keeping Requirements (RRR): Section 2.1.2 Market Monitoring Information | Ontario Energy Board**

Preamble:
OEB staff has prepared the tables below from Lakefront Utilities' RRR filed data.

Table 3: Customer Numbers

Customer Class	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
General Service < 50 kW	1,082	1,085	1,116	1,123	1,136	1,113	1,128	1,134	1,156
General Service >= 50 kW	126	128	116	114	110	102	104	100	100
Residential	8,917	9,001	9,117	9,213	9,300	9,424	9,524	9,601	9,825
Sentinel Lighting Connections	48	48	48	49	46	67	51	51	51
Street Lighting Connections	2,725	2,929	3,182	3,082	3,082	3,082	3,082	3,082	3,082
Unmetered Scattered Load Connections	86	84	84	84	82	80	82	86	91

Table 4: Yearly Customer Count Change

Customer Class	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
General Service < 50 kW	0.3%	2.9%	0.6%	1.2%	-2.0%	1.3%	0.5%	1.9%
General Service >= 50 kW	1.6%	-9.4%	-1.7%	-3.5%	-7.3%	2.0%	-3.8%	0.0%
Residential	0.9%	1.3%	1.1%	0.9%	1.3%	1.1%	0.8%	2.3%
Sentinel Lighting Connections	0.0%	0.0%	2.1%	-6.1%	45.7%	-23.9%	0.0%	0.0%
Street Lighting Connections	7.5%	8.6%	-3.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Unmetered Scattered Load Connections	-2.3%	0.0%	0.0%	-2.4%	-2.4%	2.5%	4.9%	5.8%

Question(s):

a) Please verify the information in the two tables above, or correct as required.

LUI Response:

LUI confirms the accuracy of the two tables above.

Staff-6
Ref. 1: 2025 IRM Application, p. 54

Preamble:
Lakefront Utilities includes increased redundancy on the 27.6kV system and capacity for 4.16kV to 27.6kV voltage conversion program as project justifications.

Question(s):

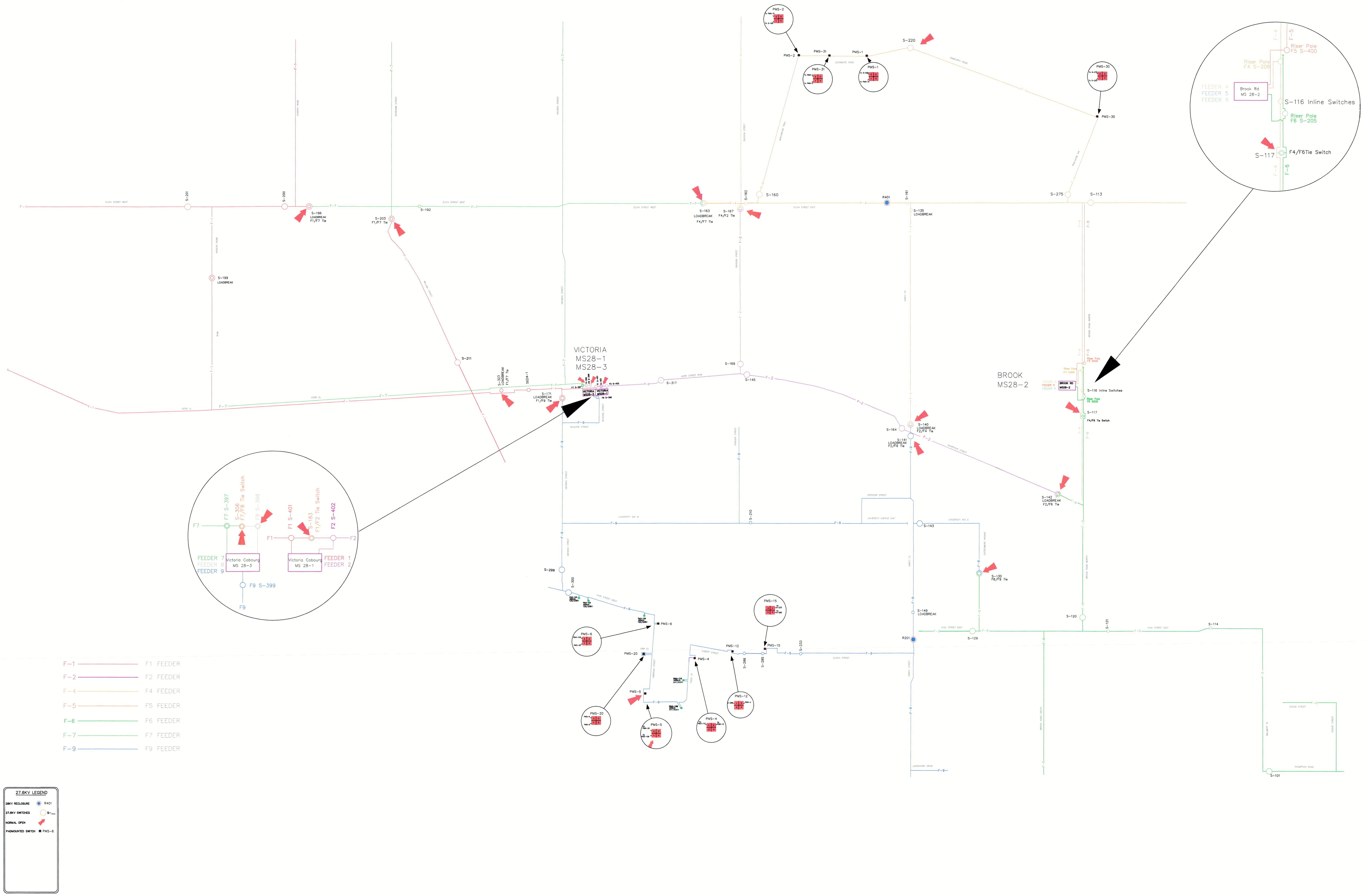
a) Are the feeders from MS 28-1, MS 28-2 and MS 28-3 able to transfer load between stations?

LUI Response:
Yes, load transfers can be done between stations.

i. If so, please identify the specific feeders and associated station.

LUI Response:

See Feeder Routing Map.



COBOURG-27.6KV 3-PH FEEDER ROUTING
December 10, 2024

LAKEFRONT UTILITIES INC. COBOURG 27.6 kV 3-PH FEEDER ROUTING
DATE: DEC 10/2024
SCALE: NOT TO SCALE

ii. If not, when will Lakefront Utilities be installing ties between the feeders?

LUI Response:

See Staff-6 a) i. response.

b) Please provide a distribution map or one line drawing showing the interties between the stations.

LUI Response:

See Staff-6 a) i. response.

c) What is the projected retirement year for each of the 4kV stations MS 2, MS 3 and MS 5?

LUI Response:

MS2, MS3 and MS5 are projected to be completely retired in 2029.

d) What amount of previously 4kV connected load was placed on MS 28-3 in each year 2023 and 2024, and forecast for 2025 through 2027?

LUI Response:

2023: 0 MW
2024: 0 MW
2025: 0 MW
2026: 0 MW
2027: 2.5 MW

Staff-7
Ref. 1: 2025 IRM Application, pp. 54-55

Preamble:
Lakefront Utilities states:

> Lakefront deliberated on invoking cost-sharing with residential developers, as directed in the Distribution System Code (DSC), to mitigate the financial impact on our existing customers. However, we are persuaded that **recent events**, including the Ontario government's intervention in overturning an OEB directive regarding Enbridge's economic evaluation for rural expansion, may override this requirement. Hence, in this application, we are proposing full recovery of the substation costs from our entire customer base. We seek OEB guidance and direction on this matter to ensure compliance and equitable cost distribution. [**Emphasis added**]

Lakefront Utilities explained that planning and design for the project was completed in Q1 2022, construction began in Q2 2022, and the substation was energized in Q4 2023.

The OEB issued the decision referenced by Lakefront Utilities regarding the economic evaluation for rural expansion for Enbridge Gas Inc. on December 21, 2023[1], and the Ontario government released a statement regarding the decision on December 22, 2023.

Question(s):

a) What agreements did Lakefront Utilities have in place prior to December 2023 for contributions in aid of construction, per the DSC, related to the new substation? Include all types of development, for example, residential subdivisions, industrial or commercial development, and unmetered loads.

   LUI response:

   One agreement was in place with a residential subdivision developer.

b) Please provide copies of the economic evaluation models for contributions to be collected from new connections, that were prepared prior to December 2023, related to the new substation.

   i. If Lakefront Utilities did not prepare economic evaluations for new customer loads connected to the substation, please prepare the evaluations retroactively as if they had been prepared prior to connecting the loads. OEB staff wishes to see what capital contributions would have been collected if Lakefront Utilities had followed the DSC.

[1] Decision and Order, EB-2022-0200, Enbridge Gas Inc., December 21, 2023

LUI Response:

LUI did prepare an economic evaluation prior to December 2023

c) Please provide a list of new developments and/or customers supplied by the 27.6kV system since 2020 and include:

LUI Response:

Subdivision

Year	Subdivision Name
2020	None
2021	New Amherst Stage 2, Phase 2
2022	Nickerson Woods
	Gates of Camelot Stage 5, Phase 1
2023	Densmore Meadows
	Tribute Phase 1
	Gates of Camelot Stage 5, Phase 2
	Mason Homes 425 King St. E
2024	None

Commercial

Street #	Street Name
1125	ELGIN WEST
555	COURTHOUSE ROAD
1025	ELGIN WEST
702	ONTARIO STREET
941	CHARLES WILSON PKWY
1154	DIVISION STREET
8950	DANFORTH ROAD
990	DIVISION STREET
1043	DIVISION STREET
160	DENSMORE ROAD
163	ELGIN EAST
299	ELGIN EAST
155	DODGE STREET
432	KING EAST
428	KING EAST
135	ORR STREET
82	MUNROE STREET
114	DIVISION STREET

i. The corresponding economic evaluation model for contributions to be collected from these developments and/or customers if Lakefront Utilities did apply the DSC (and identify proportion that would be allocated to substations).

LUI Response:

The economic evaluation model for contributions to be collected from the one development prior to December 2023, is highlighted below.

TOTAL REVENUE OVER REVENUE HORIZON (BEFORE TAX)				$1,129,631.46	PV	$ 634,747.65
Taxes, Tax Credits, and Other Adjustments:						
		Rate				
	PV Income Taxes	26.50%	$ (20,074.90)			
	CCA Tax Shield	8.00%	$ 12,100.44			
	PV Working Capital (PV of revenue less O&M)		$ 75,754.33			
	PV of Taxes, Tax Credits and Other Adjustments		$ (7,974.46)			$ (7,974.46)
	Discount Rate for PV	Year 1	Year 2-25			
		4.9237%	4.9237%			
REVENUE AFTER TAX					PV	$ 626,773.19
Expansion deposit - This connection will require an expansion deposit and a capital contribution						
	Forecasted Revenues			$ 634,747.65		$ 634,747.65
	Projected Capital Costs			$ 371,336.65		
	Ongoing Maintenance			$ 558,993.32		
			Total	$ 930,329.97		$ -
TOTAL EXPANSION DEPOSIT REQUIRED (BEFORE TAX)						$ 634,747.65
Summary of Costs and Revenues:						
	Total Cost of Connection (Capital and O&M)			$ 930,329.97		
	Less Revenue After Tax			$ 626,773.19		
	Capital Contribution			$ 303,556.78		$ 303,556.78
	Expansion deposit			$ 634,747.65		$ 634,747.65
	Expansion Deposit to be retained for two year warrantee period (if applicable)			$ 63,474.77		
TOTAL AMOUNT TO BE PAID BY CUSTOMER (PLUS HST)						$ 938,304.43
Net Due to Developer upon energization						
	Developer Capital Costs					$ 371,336.65
	Capital Contribution					$ (303,556.78)
	Capital Contribution - substation					$ (32,343.75)
	Net Due to Developer upon energization (Plus HST)					$ 35,436.12

ii. The amount of contribution collected by Lakefront utilities from the developers and/or customers.

LUI Response:

For this developer the amount is $32,343.75

d) Please provide a forecast of developments that are in the planning or construction stages for the five years after the substation commissioning date (December 2023), including the project loads, and the potential contributions if the DSC was followed (the current version of the DSC).

LUI Response:

Subdivision Name	Number of Lots	Projected Load (kVA)	Proportional Split	Potential Contribution ($)
Tribute Phase 2	105	315	7.2%	179,058.66
Victoria Meadows	72	216	4.9%	122,783.08
New Amherst Phase 3	135	405	9.2%	230,218.28
Tribute Phase 3	163	489	11.1%	277,967.26
Tribute Phase 4	176	528	12.0%	300,136.43
Tribute Phase 5	233	699	15.9%	397,339.70
Tribute Phase 6	182	546	12.4%	310,368.35
Sunnyside Village	100	300	6.8%	170,532.06
Mistral - Brook Road North	300	900	20.5%	511,596.18
Total	**1,466**	**4,398**	**100%**	**2,500,000.00**

Staff-8
Ref. 1: 2025 IRM Application, p. 55
Ref. 2: System Expansion For Housing Developments Consultation | Engage with Us

Preamble:
Lakefront Utilities states:

> Hence, in this application, we are proposing full recovery of the substation costs from our entire customer base. We seek OEB guidance and direction on this matter to ensure compliance and equitable cost distribution.

The OEB has initiated a stakeholder consultation to explore different cost recovery approaches for system expansion for housing developments. On October 24, 2024, after the filing of this application, a report to the Minister of Energy and Electrification

(Minister) was published on the consultation web page, which also contains a reply from the Minister.

On November 5, 2024, the OEB released a Bulletin regarding Connection of New Load[2] that states:

> OEB staff would like to remind distributors of their obligations under the DSC to provide customers with information on connection costs and economic evaluation of any system expansion work. Distributors must ensure customers receive complete and timely details on the costs, inputs and assumptions used in the economic evaluation.

On November 18, 2024, the OEB released a notice regarding a proposal to amend the DSC[3], which includes changing the revenue horizon for residential connections to 40 years for and outlines expectations prior to the amendments coming into force.

Question(s):

a) What consideration did Lakefront Utilities give to the OEB's consultation *System Expansion for Housing Developments* in preparing this application.

LUI Response:

In preparing this application, Lakefront Utilities considered the Ontario Energy Board's (OEB) ongoing System Expansion for Housing Developments consultation, initiated in March 2024. This consultation aims to review and potentially revise policies related to the connection and revenue horizons for housing developments, aligning with the provincial goal of constructing 1.5 million new homes.

We acknowledge the OEB's efforts to explore alternative cost recovery approaches that balance the financial responsibilities between developers and existing ratepayers. However, given that the consultation is still in progress and no definitive policy changes have been implemented, Lakefront Utilities has proceeded with this application based on the current regulatory framework incorporating a hybrid solution.

We are committed to staying informed about the outcomes of the OEB's consultation and will adjust our practices accordingly to ensure compliance and equitable cost distribution once new guidelines are established.

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[2] Bulletin: Expectations for Distributors to Support Timely Connection of New Load
[3] Notice of Proposal to Amend the Distribution System Code

b) At this time, and considering the recent communications on the consultation page, is Lakefront Utilities still requesting guidance from the OEB? Please explain.

LUI Response:

Considering the recent communications from the Ontario Energy Board (OEB) regarding the System Expansion for Housing Developments consultation, Lakefront Utilities acknowledges the evolving regulatory landscape. Notably, the OEB's Report to the Minister on System Expansion for Housing Developments, published on October 24, 2024, outlines recommendations to support the government's housing objectives. Additionally, the OEB's Bulletin on Load Connections issued on November 5, 2024, emphasizes distributors' obligations under the Distribution System Code (DSC) to provide customers with comprehensive and timely information on connection costs and economic evaluations. Furthermore, the OEB's Notice of Proposal to Amend the DSC, released on November 18, 2024, proposes extending the revenue horizon for residential connections to 40 years, among other changes.

In light of these developments, Lakefront Utilities remains committed to ensuring compliance with current regulations and aligning with the OEB's evolving policies. We recognize that the proposed amendments and guidance aim to facilitate housing development while maintaining equitable cost distribution. Therefore, we continue to seek the OEB's guidance to navigate these changes effectively and to implement cost recovery approaches that are both compliant and fair to all stakeholders.

By engaging with the OEB and adhering to the latest directives, Lakefront Utilities aims to support the timely connection of new load customers and contribute to the province's housing development goals, all while ensuring that cost allocations are just and transparent.

c) What impact will the change in revenue horizon for residential connections have to Lakefront Utilities operations on a go forward basis, if the DSC is amended as proposed?

LUI Response:

The Ontario Energy Board (OEB) has proposed amendments to the Distribution System Code (DSC) to facilitate housing development connections. These amendments include extending the revenue horizon for residential connections from 25 to 40 years and, for qualifying housing developments, extending the connection horizon to a maximum of 15 years.

Implications for Lakefront Utilities:

1. Economic Evaluations:
   - Extended Revenue Horizon: With a 40-year revenue horizon, Lakefront can account for a longer period of customer contributions when evaluating the financial viability of system expansions. This extension reduces the immediate capital contributions required from developers, as the anticipated revenue over a more extended period offsets the initial costs. Consequently, Lakefront may experience a decrease in upfront capital from developers, necessitating careful financial planning to manage cash flows and ensure sufficient funding for infrastructure projects.

2. Cost Allocation:
   - Broader Cost Distribution: The extended revenue horizon allows for the distribution of expansion costs over a more extended period and among a larger customer base. This approach aligns with the government's objective to reduce barriers to housing development by lowering initial costs for developers. However, it also implies that existing and future ratepayers will share the financial responsibility for new infrastructure, potentially leading to slight increases in rates to cover the long-term recovery of expansion costs.

3. Operational Planning:
   - Infrastructure Investment: Lakefront must strategically plan infrastructure investments to accommodate anticipated growth, considering the extended timelines for cost recovery. This planning involves forecasting future demand accurately to ensure that investments are prudent and align with both regulatory expectations and community needs.
   - Regulatory Compliance: Adapting to the amended DSC requires updates to internal policies and procedures to ensure compliance. Lakefront will need to train staff on the new requirements and possibly invest in systems to manage the extended revenue and connection horizons effectively.

4. Financial Management:

- Revenue Forecasting: The longer revenue horizon necessitates robust forecasting models to predict customer growth and usage patterns over 40 years. Accurate forecasts are crucial to ensure that the anticipated revenues materialize, thereby supporting the financial sustainability of expansion projects.
- Risk Mitigation: Extending the period over which costs are recovered introduces risks related to changes in market conditions, customer behaviors, and technological advancements. Lakefront will need to implement risk mitigation strategies, such as regular reviews of forecasts and flexible investment plans, to adapt to unforeseen changes.

In summary, the proposed amendments to the DSC will require Lakefront Utilities to adjust its financial and operational strategies to align with the extended revenue and connection horizons. While these changes aim to facilitate housing development and distribute costs more equitably, they also introduce complexities in financial planning and operational execution that Lakefront must manage proactively.

Staff-9
Ref. 1: LUI_2025_ACM_ICM_Model_1.0_20240906

Preamble:
Lakefront Utilities has submitted the ICM Excel model filled out as if the asset was placed in service in 2025. OEB staff would like to see the model completed, as if it were completed in advance of the substation being commissioned, that is, as if it were completed as part of the 2023 IRM application that was filed in the fall of 2022.

Question(s):

a) Please prepare and submit an updated ICM model as if it had been prepared in the fall of 2022. To assist, OEB staff have prepared a list of items to change below, that is not meant to be comprehensive.
   i. Tab 1. Information Sheet. Please change Rate Year = 2023
   ii. Tab 3. Growth Factor-NUM_CALC1. Please change all values in the table labelled “2022-Board Approved Distribution Demand” and change the data in the table “Current Approved Distribution Rates” to the rates that were approved for 2023.
   iii. Tab 6. Growth Factor – DEN_CALC. Please change all values in the table labelled “2021 Actual Distribution Demand”

iv. Tab 9b. Proposed ACM ICM Projects. Please change the Proposed value for “Year 1” to $2,165,886. Also please change the related Amortization Expense and CCA expense due to the 2023 portion of the project CAPEX.

LUI Response:

See completed model submitted as file name “LUI_2025_ACM_ICM_Model_1.0_20240906_as_directed_OEB_Q9a.xlsm”.

b) Please prepare and submit a second ICM model with only the changes requested in i) through iii) above.

LUI Response:

See completed model submitted as file name “LUI_2025_ACM_ICM_Model_1.0_20240906_as_directed_OEB_Q9b.xlsm”.

c) If Lakefront Utilities is of the opinion that another model for the ICM revenue calculation is more appropriate that what has been provided in a),
   i. Please explain why Lakefront Utilities is of the opinion that their scenario is more appropriate.
   ii. Please submit the Excel version of the ICM model, if it has not already been submitted.

LUI Response to Staff-9 ci and cii:

LUI respectfully submits that the models suggested by Board Staff are not a true reflection of the reality of revenue growth. The 2022 Cost of Service load forecast, as utilized in these models, is evidently not reasonable and has undervalued LUI’s resultant rate calculations. While the appropriateness of the 2022 load forecast is not the subject of this discussion, we feel it is important to highlight its implications on the current analysis.

As demonstrated in the attached analysis and supported by our submitted Excel file “LUI_2025_ACM_ICM_support OEB Q9c.xlsm”, LUI’s position remains unchanged: the original model, as filed, provides a more accurate representation of revenue growth and rate impacts. Specifically:

- The **2022 Board-Approved (BA)** values overstate revenue growth at 7.3%, compared to the actual growth of 0.9%.

- The deviation between **2022 Actual** and **2022 BA** results in an inflated view of LUI's revenue performance, undermining the validity of projections based on these assumptions.

Applying 2023 Rates				
	2021	2022 BA	2022	2023
Revenues from Rates	$ 5,059,825	$ 5,429,578	$ 5,104,617	$ 5,177,397
	A	B	C	D
Change in Revenue		$ 369,754	$ 44,793	$ 72,779
		B - A	C - A	D - C
Growth		7.3%	0.9%	1.4%

This table illustrates a key point in the analysis regarding the impact of using the 2022 Board-Approved (BA) values from the cost of service. Specifically:

1. Revenues from Rates:
   - 2021: $5,059,825
   - 2022 BA: $5,429,578
   - 2022 Actual: $5,104,617
   - 2023: $5,177,397

2. Change in Revenue:
   - Between 2021 and 2022 BA: $369,754 (a 7.3% increase)
   - Between 2021 and 2022 Actual: $44,793 (a 0.9% increase)
   - Between 2022 and 2023: $72,779 (a 1.4% increase)

Analysis:
The use of the 2022 BA (Board-Approved) value introduces a disparity compared to actual revenue data for 2022.

The significant growth rate of 7.3% (2022 BA) does not align with the 0.9% growth seen in actual revenues.

This discrepancy emphasizes that using BA values may not accurately reflect the financial reality, as they overstate revenue growth when compared to actual data.

By extension, projections or analyses based on BA values could misrepresent financial performance or expected outcomes.

Given these findings, LUI strongly supports the continued use of its originally filed model, which aligns more closely with actual data and provides a realistic framework for future rate-setting discussions.

Staff-10

Preamble:
Lakefront Utilities last filed a cost of service application for 2022 rates, and is currently scheduled to file its next cost of service application for 2027 rates.

Question(s):

a) At this time, does Lakefront Utilities foresee filing a cost of service application for 2027 rates?

LUI Response:

Yes.

b) What is the revenue requirement for the substation project each year 2023 through 2027 under the scenario(s) in Staff-9?

LUI Response:

LUI respectfully submits that we do not agree with the assumptions and methodology outlined in Staff-9. As such, we do not believe that calculating and presenting a revenue requirement under the specified scenario is a responsible or meaningful exercise.

The assumptions underlying Staff-9 fail to align with LUI’s understanding of the substation project’s financial and operational realities. Proceeding with calculations based on these assumptions would likely misrepresent the true costs and revenue requirements associated with the project. Furthermore, adopting such a scenario would undermine the integrity of the rate-setting process by introducing a distorted view of future revenue needs.

As previously stated, LUI maintains its position as outlined in our original filing. This position reflects a more accurate and responsible framework for addressing the substation project's revenue requirement over the 2023–2027 period. We stand ready to provide further clarity or alternative scenarios based on mutually agreed assumptions that align with the realities of the project.

Staff-11
Ref. 1: 2025 IRM Application, pp. 45-46

Preamble:
Lakefront Utilities states the actual ROE for 2023 was 4.27% which represents an under-earning compared to the OEB approved ROE of 8.66% in the 2022 cost of service proceeding.

Question(s):

a) Please file a copy of the 2023 RRR 2.1.5.6 ROE filing on the record.

   LUI Response:

   See submitted file "LUI_2023_ROE.xls"

b) Please explain the variance between the approved and the achieved ROE and quantify the main drivers.

   LUI Response:

   The variance between the approved ROE and the achieved ROE is $348k shortfall based on the approved ROE of $794k and the achieved 2023 ROE of $446k. The main drivers effecting the 2023 ROE shortfall are:

   a. Infrastructure investment of the new sub station costs $79K
   b. Staffing vacancies supported by consultants $223k

Staff-12
Ref. 1: 2025 IRM Application, p. 55

Preamble:
Lakefront Utilities outlined the project timeline that planning and design for the project was completed in Q1 2022, Construction began in Q2 2022, and the substation was energized in Q4 2023.

Question(s):

a) Please confirm in which year the MS 28-3 substation was capitalized on Lakefront Utilities' Audited Financial Statements (AFSs). Please provide a copy of the AFSs and show which line items is/are related to this substation. Please provide a detailed breakdown of the project costs and the respective CCA class.

   LUI Response:

   Please see response in Staff-12 a) i).

   i. Please submit an Excel version of the CCA schedule (Schedule 8) to support the calculated CCA amount of $194,712.

      LUI Response:

      See submitted file "Staff_12a_CCA.xls"

Staff-13
Ref. 1: LUI_2025-IRM-Rate-Generator-Model_V4_20240906, Tab 6: Class A Consumption Data

Preamble:
Lakefront Utilities outlined in 2b that they have customers who transitioned between Class A and Class B during the period the Account 1580, sub-account CBR Class B balance accumulated, and in 3b mentioned that there are 3 rate classes in which there were customers who were Class A for the full year during the period the Account 1589 GA or Account 1580 CBR B balance accumulated.

Question(s):

a) Please confirm that the response in 2b is accurate.

   LUI response:

   LUI changed response to 2b in the updated IRM Rate Generator Model, attached.

b) Please fill out the table for question 3b.

LUI response:

The response provided in Staff-13a) indicates that this question is not applicable.

Staff-14
Ref. 1: LUI_2025-IRM-Rate-Generator-Model_V4_20240906, Tab 8: STS – Tax Change

Preamble:
Lakefront Utilities has provided a value of $22,913,016 as the OEB-Approved Rate Base (Cell H16) and has not provided any value for the OEB-Approved Regulatory Taxable Income (Cell H18).

Question(s):

a) As per the Revenue Requirement Workform from Lakefront Utilities' last cost of service, the OEB-Approved Rate Base was $22,919,093. Please confirm the source of Cell H16.

   LUI response:

   LUI has updated the Rate Base to $22,919,093 in the model.

b) Please fill out the value for Cell H18.

   LUI response:

   LUI has updated the value in the model.

Staff-15
Ref. 1: LUI_2025-IRM-Rate-Generator-Model_V4_20240906, Tabs 11, 15, and 20

Preamble:
On November 1, 2024, the OEB issued a letter regarding 2025 Preliminary Uniform Transmission Rates (UTRs) and Hydro One Sub-Transmission Rates. The OEB determined to use of preliminary UTRs to calculate 2025 Retail Service Transmission rates (RTSR) to improve regulatory efficiency, allowing for this data to feed into the rate applications including annual updates for electricity distributors on a timelier basis. The OEB also directed distributors to update their 2025 application with Hydro One

Networks Inc.'s (Hydro One) proposed host RTSRs. Any further updates to Hydro One's proposed host RTSRs will be reflected in the final Rate Generator Model.

On November 19, 2024, the OEB issued a letter outlining that the fixed microFIT Generator Service Classification charge (microFIT charge) would be increased from $4.55 to $5.00 for the 2025 rate year.

OEB staff has updated Lakefront Utilities' Rate Generator Model with the preliminary UTRs, proposed host RTSRs by Hydro One, and microFIT charge as follows:

UTRs

Uniform Transmission Rates	Unit	2023 Jan to Jun	2023 Jul to Dec	2024 Jan to Jun	2024 Jul to Dec	2025
Rate Description		Rate		Rate		Rate
Network Service Rate	kW	$ 5.60	$ 5.37	$ 5.78	$ 6.12	$ 6.25
Line Connection Service Rate	kW	$ 0.92	$ 0.88	$ 0.95	$ 0.95	$ 1.00
Transformation Connection Service Rate	kW	$ 3.10	$ 2.98	$ 3.21	$ 3.21	$ 3.39

Hydro One Sub-Transmission Rates

Hydro One Sub-Transmission Rates	Unit	2023	2024	2025
Rate Description		Rate	Rate	Rate
Network Service Rate	kW	$ 4.6545	$ 4.9103	$ 5.2172
Line Connection Service Rate	kW	$ 0.6056	$ 0.6537	$ 0.6537
Transformation Connection Service Rate	kW	$ 2.8924	$ 3.3041	$ 3.3041
Both Line and Transformation Connection Service Rate	kW	$ 3.4980	$ 3.9578	$ 3.9578

microFIT Charge

Rate Class	Current MFC	MFC Adjustment from R/C Model	Current Volumetric Charge	DVR Adjustment from R/C Model	Price Cap Index to be Applied to MFC and DVR	Proposed MFC	Proposed Volumetric Charge
RESIDENTIAL SERVICE CLASSIFICATION	26.8				3.60%	27.76	0.0000
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	27.71		0.0102		3.60%	28.71	0.0106
GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	100.83		4.0251		3.60%	104.46	4.1700
GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION	6037.86		2.235		3.60%	6,255.22	2.3155
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	10.76		0.016		3.60%	11.15	0.0166
SENTINEL LIGHTING SERVICE CLASSIFICATION	6.49		14.7818		3.60%	6.72	15.3139
STREET LIGHTING SERVICE CLASSIFICATION	2.04		5.3511		3.60%	2.11	5.5437
microFIT SERVICE CLASSIFICATION	4.55					5.00	

Question(s):

a) Please confirm the accuracy of the Rate Generator Model updates, as well as the accuracy of the resulting Retail Transmission Service Rates following these updates.

LUI Response:

LUI is confirming accuracy of the Rate Generator Model updates.

Staff-16
Ref. 1: LUI_2025-IRM-Rate-Generator-Model_V4_20240906, Tabs 18 and 21

Preamble:
On October 18, 2024, the OEB issued a letter regarding updated Regulated Price Plan (RPP) prices effective as of November 1, 2024. Also, effective November 1, 2024, the Ontario Government's Ontario Electricity Rebate (OER) was changed to 13.1%.

OEB staff has updated Lakefront Utilities' Rate Generator Model with the updated RPP and OER values as follows:

Time-of-Use RPP Prices and Percentages

As of	November 1, 2024		
Off-Peak	$/kWh	0.0760	64%
Mid-Peak	$/kWh	0.1220	18%
On-Peak	$/kWh	0.1580	18%

Ontario Electricity Rebate (OER)

Ontario Electricity Rebate (OER)	$	13.10%

Question(s):

a) Please confirm the accuracy of the Rate Generator Model updates for the RPP and OER values.

   LUI Response:

   LUI is confirming the accuracy of the Rate Generator Model updates for the RPP and OER values.

Staff-17
Ref. 1: LUI_2025-IRM-Rate-Generator-Model_V4_20240906, Tab 3, Continuity Schedule

Preamble:
On September 13, 2024, the OEB published the 2024 Q4 prescribed accounting interest rates applicable to the carrying charges of deferral, variance and construction work in progress (CWIP) accounts of natural gas utilities, electricity distributors and other rate-regulated entities.

Question(s):

a) Please update Tab 3 (Continuity Schedule) as necessary to reflect the Q4 2024 OEB-prescribed interest rate of 4.40%.

LUI Response:

LUI has updated the values in the model.

Staff-18
Ref. 1: LUI_2025-IRM-Rate-Generator-Model_V4_20240906, Tab 21: Bill Impacts

Preamble:
Lakefront Utilities has provided bill impacts which include the effect of both ICM and Group 1 DVA rate riders.

Question(s):

a) Please provide a table with bill impacts for each rate class that only accounts for the ICM component (i.e., the Group 1 DVA element is not included).

LUI Response:

Table 2

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 1.74	6.5%	$ (2.99)	-7.5%	$ (2.83)	-5.3%	$ (2.83)	-2.1%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 3.56	6.7%	$ (12.94)	-13.7%	$ (12.16)	-8.9%	$ (12.15)	-3.0%
GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 59.08	6.5%	$ (474.24)	-25.0%	$ (454.70)	-14.2%	$ (513.81)	-3.9%
GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 805.28	6.5%	$ (9,742.23)	-32.0%	$ (9,443.38)	-18.4%	$ (10,671.02)	-4.8%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh	$ 1.37	6.7%	$ (2.65)	-8.6%	$ (2.53)	-5.9%	$ (2.52)	-2.4%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kW	$ 0.62	6.5%	$ 0.12	1.1%	$ 0.13	1.1%	$ 0.13	0.7%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 0.16	6.4%	$ (0.04)	-1.2%	$ (0.03)	-0.9%	$ (0.03)	-0.4%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ 1.74	6.5%	$ (2.99)	-7.5%	$ (2.83)	-5.3%	$ (3.20)	-2.0%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 1.74	6.5%	$ (0.14)	-0.4%	$ (0.08)	-0.2%	$ (0.08)	-0.1%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ 1.74	6.5%	$ (0.14)	-0.4%	$ (0.08)	-0.2%	$ (0.09)	-0.1%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ 3.21	6.7%	$ (9.99)	-12.2%	$ (9.37)	-8.1%	$ (10.58)	-2.7%

Staff-19
Ref. 1: 2025 IRM Application, p. 7
Ref. 2: LUI_2025_ACM_ICM_Model_1.0_20240906, Tab 1, Information Sheet

Preamble:
Lakefront Utilities states, “LUI acknowledges that the Board released an update on June 20, 2024, for an Input Price Index of 3.60%.”

In the ICM Excel Model, Lakefront Utilities has provided a value of 3.7% for Cell F40 (Current IPI).

Question(s):

a) Please update the ICM model to reflect the correct value of 3.6%.

LUI Response:

LUI updated the ICM model with 3.6%.

Staff-20
Ref. 1: LUI_2025_ACM_ICM_Model_1.0_20240906, Tab 3, Growth Factor – NUM_CALC1

Preamble:
Lakefront Utilities has provided Units as $/KWh in Cells B21 and B22.

Question(s):

a) Please confirm the accuracy of the units reported in Cells B21 and B22. If incorrect, please revise accordingly.

LUI Response:

In Tab 6, cells B21 and B22 are revised, accordingly.

Staff-21
Ref. 1: LUI_2025-IRM-Rate-Generator-Model_V4_20240906, Tab 6, Class A Consumption Data

Preamble:
As per the data provided by Lakefront Utilities, there are 3 rate classes in which there were customers who were Class A for the full year during the period the Account 1589 GA or Account 1580 CBR B balance accumulated.

Rate Classes with Class A Customers - Billing Determinants by Rate Class

	Rate Class		2023
Rate Class 1		kWh	
		kW	
Rate Class 2		kWh	
		kW	
Rate Class 3		kWh	
		kW	

Question(s):

a) Please fill out the table under section 3b (snapshot above included for reference).

LUI Response:

In Tab 6, section 3b should have been 0 as to not constitute entering the values for Class A kWh.